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Flexibility as a Service

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Authors:

This paper is the result of a collaborative work of ETIP SNET WG3 "Flexible Generation", led by Rosaria Volpe (University of Catania, Italy).

Editors:

Rosaria Volpe (University of Catania, Italy), Olaf Bernstrauch (Siemens Energy AG, Germany), Anders Stuxberg (Siemens Energy AB, Sweden)

Lead Authors:

Rosaria Volpe (University of Catania, Italy)

Olaf Bernstrauch (Siemens Energy AG, Germany)

Anders Stuxberg (Siemens Energy AB, Sweden)

Federico Bianchi (RSE, Italy)

Titouan Chilou (Think Smartgrids, France)

Kamalanathan Ganesan (R&D Nester, Portugal)

Nikos Hatziargyriou (National Technical University of Athens, Greece)

Contributing Authors:

Hossein Ameli (Imperial College of London, UK)

Grazia Barchi (EURAC, Italy)

Rasmus Bramstoft (Technical University of Denmark, Denmark)

Jose Pablo Chaves (Comillas Pontifical University, Spain)

Xavier de Beauffort (Luminus, Belgium)

Do Thai Phuong (CEA-INES, France)

Nickolas Frydas (IPTO S.A.- ADMIE, Greece)

Mathieu Gallisot (CEA, France)

Albana Ilo (TU Wien, Austria)

Rishabh Jain (Siemens Energy AG)

Oleksandr Novykh (Universidad de La Laguna, Spain)

Klaus Payrhuber (INNIO Jenbacher GmbH & Co OG, Austria)

Ricardo Pastor (R&D Nester, Portugal)

Vito Ponzo (Enel Grids, Italy)

Stavros Spyridakos (IEECP, Netherlands)

Goran Strbac (Imperial College of London, UK)

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Unit B5 – Digitalisation, Competitiveness, Research and Innovation

Contact: Mugurel-George Paunescu
E-mail: Mugurel-George.PAUNESCU@ec.europa.eu

European Commission
B-1049 Brussels

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1. EXECUTIVE SUMMARY

Europe's energy system is undergoing rapid transformation, with growth perspectives that are different from the logic on which it was built. In 2025, wind and solar technologies together generated more EU electricity than all fossil fuels for the first time[1]. By 2030, renewables are expected to account for more than 60% of EU electricity consumption[2]. With the progressive substitution of dispatchable capacity by variable generation, managing the residual load, which is defined as the net demand to be covered by controllable resources, becomes difficult to predict and more expensive to manage.

Flexibility is crucial in modern power systems, especially as grids integrate renewable energy sources that are inherently variable. Flexible assets help balance the grid by dispatching power to cover the difference between supplied renewable power and total demand, i.e., what is generally referred to as "residual load"[3]. Flexibility is therefore a system resource that must be explicitly organised, procured and remunerated. ENTSO-E estimates that flexibility needs across all timeframes will roughly double between 2025 and 2033[4] and, where it is missing, the most significant consequences can be read in renewable curtailment, higher balancing costs and price volatility and also in potential risks in terms of security of supply. Distributed flexibility resources are key to reducing grid stress since peak transmission need can be reduced, both by adaptive demand and by power provided where needed, instead of being transferred. Long-term this means less required investment in grid reinforcement and short term it can help in accelerating dispatch of renewable power as well as enable faster electrification of e.g. industry than what is possible if only grid expansion is undertaken.

Meeting these needs is not only a matter of owning flexible assets, but of organising flexibility as a service that can be specified, procured, delivered, measured and remunerated. Flexibility as a Service (FaaS) reframes flexibility from an intrinsic property of certain technologies into a tradable service whose value depends on when and where it is delivered. Three layers make this possible: a contractual layer that defines what is requested and how it is paid; a digital layer of interoperable communication, metering and data exchange that allows activation to be triggered and delivery to be verified; and a market layer that sends price signals reflecting the real-time, location-specific value of flexibility.

The flexibility resources available to Europe are diverse and, to a large extent, already in place. They span flexible generation and storage, demand-side response across buildings, district heating and industry, and distributed assets aggregated into market-relevant volumes. Turning these into reliable services requires coordinated operation: workable TSO–DSO coordination models, cross-vector strategies that link electricity with heat and gas, and resilience and cybersecurity safeguards as control becomes more distributed and data-dependent. Trust in delivery rests on transparent modelling, data interoperability and validation methods that make performance measurable and comparable.

Historically, growing demand and new generation have been accommodated mainly through capital-intensive reinforcements and expansion of network assets. The pace of electrification in transport, heating and industry,

[1] Ember. (2025). *Wind and solar generated more power than fossil fuels in the EU for the first time in 2025*. [Online]. Available: https://ember-energy.org/latest-updates/wind-and-solar-generated-more-power-than-fossil-fuels-in-the-eu-for-the-first-time-in-2025/

[2] European Commission. (n.d.). *Electricity market design*. [Online]. Available: https://energy.ec.europa.eu/topics/markets-and-consumers/electricity-market-design_en

[3] ENTSO-E. (2024). *System Flexibility Needs for the Energy Transition*. Brussels: European Network of Transmission System Operators for Electricity. [Online]. Available: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/System_Needs/entso-e_System_Needs_Energy_Transition_v10.pdf

[4] ENTSO-E, System Flexibility Needs for the Energy Transition, op. cit.

however, cannot be sustained by grid infrastructure expansion alone. System operators are therefore increasingly expected to test non-traditional alternatives, such as demand management, storage, flexible agreements and data-driven network management, before committing to reinforcement, and to contract flexibility as an operational resource through local flexibility markets and bilateral agreements. Directive (EU) 2024/1711 codifies this logic while bounding it, as reinforcement remains the structural solution and flexible connections are converted to firm once the network is ready, becoming permanent only where reinforcement is not the efficient option. The shift implies a better use of existing assets, and it is what turns flexibility from a system property into a procurable service.

On the market and regulatory side, the 2024 reform of the EU electricity market design (Regulation (EU) 2024/1747) marks a turning point. It allows Member States to introduce non-fossil flexibility support schemes and requires regular national assessments of flexibility needs. This confirms that flexibility is now treated as a system resource to be planned and procured rather than a by-product of operation. Realising this in practice depends on opening markets to new actors, aggregators, energy communities and small-scale assets, and on transitional instruments such as regulatory sandboxes.

This white paper investigates FaaS as a contributor to a net-zero, high-RES European energy system. Its main recommendations, intended for system operators, regulators and industry, are to standardise flexibility products and interfaces, to invest in the digital infrastructure that makes delivery verifiable, and to design remuneration that reflects the true temporal and locational value of flexibility.

2. INTRODUCTION AND MOTIVATION

The European energy landscape is undergoing a structural transformation characterised by different challenges, the most visible of which is flexibility. As variable renewables displace dispatchable generation, the system needs to compensate more frequently and quickly, and from more distributed sources than before. This challenge is already visible in negative price events or in rising dispatch volumes, with more demanding operation for local grids.

The role of flexibility in the energy system has changed. Previously, flexibility was considered as an implicit by-product of how a small number of large plants were operated; now, it has to be procured deliberately, from many more and smaller providers, and across timeframes ranging from seconds to seasons. This is the shift that motivates this study, in which flexibility is treated as a service, with explicit products, contracts, data exchange and remuneration. The remainder of this chapter sets out why the need for flexibility is growing, what "Flexibility as a Service" means in this context, and what the paper sets out to achieve.

The scope of FaaS as used in this paper is deliberately broad. It covers flexibility from all asset types, generation, storage, demand-side management, distributed and aggregated resources, and across all relevant time horizons, from real-time frequency response to seasonal balancing. It spans the full chain of actors, from individual consumers and prosumers through aggregators and energy communities to distribution and transmission system operators. It also encompasses both the technical and the institutional dimensions, recognising that a flexible asset should rely on precise rules and contracts, as well as a reliable infrastructure to allow its activation.

2.1 Energy system transformation and the growing need for flexibility

The power system that most European countries built over the twentieth century was designed around the logic that large and controllable generators follow load, with frequency managed centrally. The concept of flexibility already existed and was embedded in the ramping capability of gas power plants, in the management of hydro plants and in interconnections between national systems. In this sense, flexibility was not conceived as a system property that needed to be explicitly organised as a market resource.

Renewables, especially wind and solar, have grown from a marginal share to a structurally dominant position in the EU generation mix in less than a decade, with a combined share that rose from around 17% of EU electricity in 2019 to roughly 30% in 2025, the year in which wind and solar together overtook fossil generation[5].

Europe installed more than 77 GW of RES in 2024 alone (84% of this capacity is solar PV) and plans to reach more than 1,200 GW of RES capacity by 2030, from around 800 GW today, which means 100 GW of new renewable capacity every year[6].

The following figure shows the electricity in the EU-27 by generation source for previous and following years:

[5] Ember. (2025). *European Electricity Review 2025*. Ember. [Online]. Available: https://ember-energy.org/app/uploads/2025/01/EER_2025_22012025.pdf

[6] International Renewable Energy Agency. (2024). *Solar PV supply chains: Technical and ESG standards for market integration*. IRENA, Abu Dhabi. [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2024/Sep/IRENA_Solar_PV_supply_chains_technical_ESG_standards_2024.pdf

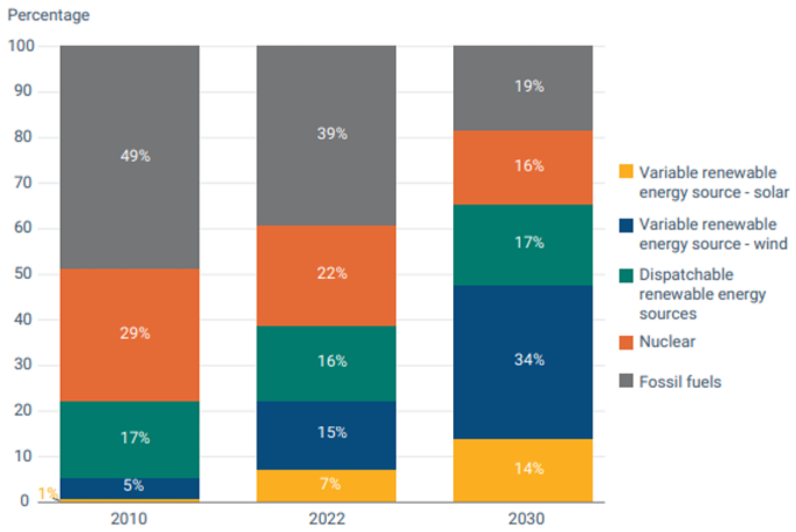

Figure 1 - Electricity in the EU-27 by generation source

One side effect is that grid connections are typically sized to accommodate peak generation output, even though such peaks are infrequent and of limited market value (redundancy built inherently in networks). As a result, network infrastructure is often underused, and the grid cost share of the electricity bill is expected to increase by 66% for household consumers by 2050.

By 2030, renewables are expected to account for more than 60% of EU electricity consumption[7]. The operational consequence is that as dispatchable capacity diminishes and variable generation expands, the residual load, i.e., the net demand that must be covered by controllable resources, becomes harder to predict. The system needs more frequent adjustments over shorter timeframes and from a broader set of sources. According to the ENTSO-E, flexibility requirements across all relevant timeframes will approximately double between 2025 and 2033, with daily needs ranging anywhere from 0.7 to 2.6 TWh[8].

One of the most important effects of the current lack of "flexibility" is that more and more frequent periods of high renewable output combined with low demand are driving electricity prices to very low or negative levels. This is closely linked with a structural challenge in modern power systems known as the 'duck curve', high shares of variable solar generation flood the system around midday, followed by steep ramps in residual load in the evening as solar output falls and demand rises. In some months of 2025, certain regions saw more than 18% of hours with negative prices, while daily price swings have increased five-fold since 2020. ACER expects flexibility needs to double already by 2030, with significant seasonal flexibility needs[9].
Therefore, system operators face a dual operational challenge:

- Very low or negative prices, which makes investments in RES unattractive to investors.
- Local grid congestion, where available network capacity is insufficient to transport electricity to where it is needed.

A growing need in a market is always manifested through increased prices, as demonstrated by the energy and ancillary services price spikes. For example, the European electricity market, a system with 50% RES generation, exhibited daily price swings 6 and 4 times higher in 2022 and 2025 respectively than in 2020[10].

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[7] European Commission, Electricity market design, op. cit.
[8] ENTSO-E, System Flexibility Needs for the Energy Transition, op. cit.
[9] European Environment Agency and European Union Agency for the Cooperation of Energy Regulators. (2023). *Flexibility solutions to support a decarbonised and secure EU electricity system* (EEA/ACER Report 09/2023). Publications Office of the European Union, Luxembourg. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Publications/EEA-ACER_Flexibility_solutions_support_decarbonised_secure_EU_electricity_system.pdf
[10] European Union Agency for the Cooperation of Energy Regulators. (2025). *Progress of EU electricity wholesale market integration – 2025 Monitoring Report*. ACER. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-2025-Electricity-market-integration.pdf

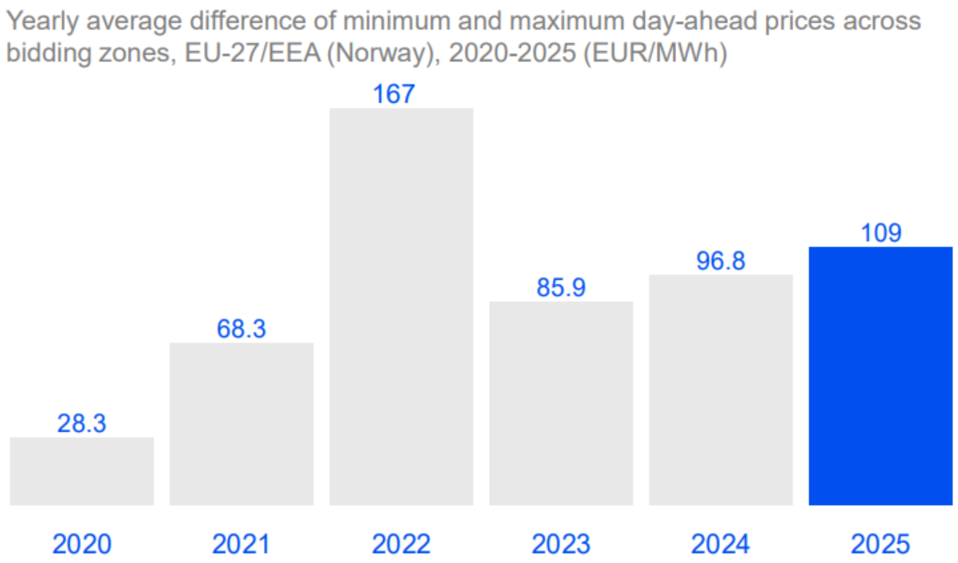

Figure 2 - Volatility of electricity market prices because of increasing stochasticity [11]

Value of flexibility: By adding even modest amounts of flexibility, the power system could significantly reduce grid buildout needs, ease congestion, reduce volatility of prices and therefore lower costs for consumers. Flexibility solutions, and especially demand-side response, can also be implemented much faster than large infrastructure projects, which often face years of planning, permitting and construction. The cost of insufficient flexibility, on the other hand, is already visible: RES curtailment volumes increased by around 55 % in 2024, and by 2030 Europe could need to redispatch volumes equivalent to the annual electricity consumption of the Iberian Peninsula in 2024. EU redispatch costs amounted to EUR 5.2 billion in 2022 and could rise to as much as EUR 26 billion by 2030, costs that are ultimately passed down to consumers through the electricity bill. Storage is part of the answer: European battery storage capacity doubled from 8 GW in 2022 to 16 GW in 2023, reaching around 35 GW by the end of 2024, and combined with 53 GW of pumped hydro, Europe now has at least 89 GW of energy storage capacity[12]. Yet storage and transmission alone cannot meet all flexibility needs cost-effectively, which is why energy storage and demand response are becoming increasingly prominent in the broader portfolio of strategies for enhancing flexibility.

At the same time, the demand side is changing in parallel. The electrification of transport, heating and parts of industry is adding new loads to the system, but it is also creating, for the first time at scale, a demand side that is technically capable of responding to system signals. An EV fleet, a portfolio of heat pumps, a district heating network with thermal storage are not conventional consumers, but all of them can shift consumption in time, reduce load at peak or absorb excess generation when prices are low. This is also supported by a study of the European Parliament's on flexibility in the EU energy system, where it is noted that promoting flexible demand can materially reduce the additional capacity investments that electrification would otherwise require[13].

Where flexibility is insufficient, the system faces challenges like renewable curtailment, elevated balancing

[11] Figure taken from: European Union Agency for the Cooperation of Energy Regulators. (2025). *Progress of EU electricity wholesale market integration – 2025 Monitoring Report*. ACER. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-2025-Electricity-market-integration.pdf

[12] European Commission, Directorate-General for Energy. (n.d.). *Key facts on energy storage*. European Commission. [Online]. Available: https://energy.ec.europa.eu/topics/research-and-technology/energy-storage/key-facts-energy-storage_en

[13] European Parliament. (2025). *Increasing Flexibility in the EU Energy System – Technologies and policies to enable the integration of renewable electricity sources*. Brussels: European Parliament, Policy Department for Economic, Scientific and Quality of Life Policies. [Online]. Available: https://www.europarl.europa.eu/RegData/etudes/STUD/2025/769347/ECTI_STU(2025)769347_EN.pdf

costs, price volatility and, in extreme cases, lack of supply during prolonged periods of low wind and solar output.

2.2 From network reinforcement to flexibility-enabled network development

The above-described underutilisation follows from the way networks have historically been developed. Growing demand and new generation capacity have been accommodated primarily through capital-intensive reinforcement and expansion of network assets, dimensioned on infrequent peaks and on a deterministic view of future load. This approach remains indispensable, and no realistic pathway to a decarbonised European system avoids substantial grid investment, but it cannot be conceived as the only sufficient strategy. The European Commission's Action Plan for Grids estimates that around EUR 584 billion of grid investment is required by 2030, at a time when roughly 40% of EU distribution grids are more than forty years old[14]; and, as noted above, reinforcement projects face multi-year planning, permitting and construction lead times that the pace of electrification in transport, heating and industry does not accommodate.

System operators are therefore increasingly required to assess non-network alternatives before committing to reinforcement. These include demand-side management and demand response, storage solutions (distributed and grid-scale), non-firm or "flexible" connection agreements, and active network management to change from static, worst-case dimensioning towards dynamic, data-driven control of power flows in near-real time. Such solutions avoid an upgrade at acceptable cost and risk, since they release capacity from the existing infrastructure rather than adding new infrastructure. In parallel, distribution system operators have increasingly started considering flexibility as an operational resource, through local flexibility markets and bilateral agreements with consumers, aggregators and distributed energy resources.

The regulatory framework has moved in this direction incrementally. Article 32 of Directive (EU) 2019/944 already requires Member States to enable and incentivise DSOs to procure flexibility services, including congestion management, through transparent, non-discriminatory and market-based procedures, unless the regulatory authority establishes that such procurement is not economically efficient[15]. Article 6a, introduced by Directive (EU) 2024/1711, adds flexible connection agreements in areas where network capacity is limited or unavailable[16]. The significance of these provisions lies primarily in their combined effect rather than in their individual impact. A flexible resource is rarely viable on the strength of a single service: the same asset may contribute by many different values simultaneously. For example, relieve a distribution constraint, deliver a balancing product, hedge exposure to wholesale prices and reduce a network charge. It may be the ability to combine these value streams that determines whether both the investment and the participation are justified. New market places therefore create value not only by opening an additional revenue opportunity, but by making that opportunity compatible with the ones a resource already serves. The coordination requirement is that combined value streams must be reconciled so that a resource is neither activated twice for conflicting purposes nor remunerated twice for the same delivery. With regard to the regulatory framework, Regulation (EU) 2024/1747, adopted in June 2024, formally introduces non-fossil flexibility support schemes in the form of capacity payments. They are specifically designed to remunerate flexible assets other than conventional generation and mandates that Member States conduct regular national flexibility needs assessments[17].

[14] European Commission, Directorate-General for Energy. (n.d.). *Electrification*. European Commission. [Online]. Available: https://energy.ec.europa.eu/topics/eus-energy-system/electrification_en#electrification-action-plan

[15] European Union. (2019). *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*. Official Journal of the European Union. [Online]. Available: https://eur-lex.europa.eu/eli/dir/2019/944/oj/eng

[16] European Union. (2024). *Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design*. Official Journal of the European Union. [Online]. Available: https://eur-lex.europa.eu/eli/dir/2024/1711/oj/eng

[17] European Union. (2024). *Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design*. Official Journal of the European Union. [Online]. Available: https://eur-lex.europa.eu/eli/reg/2024/1747/oj/eng

2.3 From “flexibility” to Flexibility as a Service: rationale and scope

Flexibility as a technical concept is well established. This paper, however, is primarily concerned with how flexibility gets turned into something that can actually be procured, delivered, verified and paid for at the scale that the energy transition requires.

Europe already holds substantial latent flexibility potential in its building stock, growing EV fleet, industrial processes and distributed storage. Despite the potential, the conditions for its delivery are less advanced. A building operator willing to reduce HVAC load during a system stress event cannot do so unless there is a contract defining what is expected, a communication infrastructure that sends the signal, a metering system that records what was actually delivered, and a market mechanism that compensates for it.

Rather than treating flexibility as an intrinsic property of certain assets, FaaS treats it as a service having a value that can be recognised in a contract or a market. In this sense, the ENTSO-E's working definition captures this logic and defines flexibility as the power system's ability to manage variability and uncertainty across timeframes from seconds to years, considering also the availability of sufficient capacity under any condition [cit]. FaaS operationalises this ability by providing a service architecture in which products, standardised interfaces, measurable outcomes and remuneration mechanisms that reflect actual system value are defined.

There are different aspects that need to be considered with FaaS. First, the existence of a contractual layer, in which service agreements specify what flexibility is being requested, over what timeframe, with what notice, and under what remuneration structure. This is what makes investment in flexible assets economically rational and helps providers to quantify the revenue and justify the capital. Secondly, a digital layer must be implemented to ensure for interoperable communication protocols, smart metering and data exchange infrastructure that make it possible to activate flexibility reliably and verify delivery. Without this, markets cannot function as it is impossible to pay for a service that is unmeasurable. Third, in line with the definition, a market layer is fundamental to provide the price signals and procurement mechanisms that reflect the actual value of flexibility at a given time and location, incentivising providers to make their resources available when and where they are needed most.

2.4 Aims and objectives of the paper

In the technical and operational fields, there is already substantial literature on flexibility. In addition, there is also a growing body of research from EU-funded projects on TSO-DSO coordination, local flexibility markets and distributed resource integration. What still deserves attention is how flexibility is organised, how transitions take place, and how it is practically delivered in the European energy system. This paper aims to contribute to filling that gap by providing a structured study connecting the conceptual, operational, and policy dimensions of FaaS.

Different aspects and characteristics of FaaS are discussed in this paper. The first consists of the adoption of a shared and precise definition of FaaS and its constituent elements, distinguishing it from demand response, ancillary services or capacity mechanisms, and defining the technical boundaries within which flexibility services can be specified and delivered (Chapter 3). The second consists of the asset and resource mapping by providing a systematic overview of the flexibility resources available in the European system, along with their technical characteristics, current market readiness and potential contribution across different service types and time horizons (Chapter 4). The third provides a detailed operational analysis, i.e. examining how FaaS is integrated into system operations in practice, including TSO-DSO coordination frameworks, cross-vector strategies, cybersecurity requirements, and lessons from ongoing demonstration projects (Chapter 5). Going further, market and policy assessment are addressed by identifying the data infrastructure, market design features, regulatory provisions and transitional mechanisms that determine whether FaaS can scale beyond pilots and isolated national markets (Chapters 6, 7, and 8).

3. CONCEPTUAL FRAMEWORK OF FLEXIBILITY AS A SERVICE

FaaS represents a fundamental transformation in how flexibility is conceptualised, traded and deployed within modern energy systems. Unlike traditional approaches, such as fixed demand response programs or centralised storage solutions, FaaS introduces a service-oriented, market-driven framework that leverages digitalisation, real-time data exchange and stakeholder collaboration to unlock latent flexibility across the energy ecosystem *(ENTSO-E, 2020; Lund et al., 2021)*. This shift is critical for two reasons:

1. The Energy Transition Imperative: As the share of variable renewable energy (VRE), such as wind and solar, continues to grow, energy systems face increasing challenges related to intermittency, variability and grid stability *(IEA, 2023).* FaaS provides a mechanism to balance supply and demand in real time, reducing the need for costly grid reinforcements or fossil-fuel-based backup generation.
2. The Rise of Digital Energy Systems: The proliferation of smart meters, IoT devices and AI-driven analytics has enabled granular, real-time monitoring and control of energy assets. FaaS capitalises on these technologies to create flexibility markets in which flexibility is no longer a by-product of system operation but a service that can be contracted, measured and, finally, remunerated *(Eurelectric, 2022; JRC, 2022).*

This section defines flexibility and FaaS, outlines its core principles and articulates its systemic value within a net-zero, high-RES energy system. By doing so, it sets the foundation for the definition and technical boundaries of flexibility (3.1), flexibility as a systemic action (3.2), time horizons of flexibility (3.3), and role of FaaS in a net-zero and high-RES energy system (3.4).

3.1 Definition of flexibility: technical boundaries and glossary

Flexibility is not a new concept in energy systems. Historically, it has been provided by conventional generators that could ramp up or down their output to match demand. However, the transition to high shares of renewable energy sources (RES) and the push towards net-zero emissions have transformed the role of flexibility. Today, flexibility is no longer confined to large-scale power plants but is increasingly provided by distributed resources, including:

- Demand-side flexibility: Consumers adjusting their consumption patterns (e.g., shifting the use of appliances, electric vehicles, or heating systems).
- Storage systems: Batteries, pumped hydro, thermal storage or buffering energy by production of synthetic fuels or e-fuels that can absorb or release energy on demand.
- Intermittent generation: Flexibility can also come from renewable generators, which can curtail output or, in some cases, be asked to increase production when conditions allow.

This shift has introduced new technical, economic and regulatory challenges, as well as opportunities to rethink how flexibility is procured, valued and delivered.

Because several established concepts overlap with flexibility, it is useful to state precisely what FaaS adds. FaaS is not a synonym for any single existing mechanism; it is the organising layer that turns a technical capability into a contracted and remunerated service, whatever the underlying resource.

- Demand response is one source of flexibility (consumers shifting or reducing load). FaaS is the broader service framework through which that response, alongside storage, generation and sector-coupled assets, is specified and activated, and finally also verified and paid.
- The concept of FaaS is wider as it covers non-frequency ancillary services, energy and congestion services across markets and time horizons, not only the system-security products procured by the TSO.
- Capacity mechanisms remunerate availability during scarcity. They target a single service and have historically favoured conventional plants. FaaS instead values flexibility wherever and whenever it has

system value, and is technology-neutral by design.

Technical boundaries of flexibility

The technical boundaries of flexibility are determined by the physical and operational constraints of the resources providing it. These boundaries include:

1. Power Capacity Limits

Each flexible resource has a maximum and minimum power output or consumption that it can provide. For example, a battery storage system with a 1 MW rating can charge and discharge within this limit, thus operating at a power range of -1 MW to 1 MW; a heat pump can modulate its consumption between 0 kW (off) and its rated capacity (e.g., 10 kW); demand response programs may require consumers to reduce their load by a certain percentage (e.g., 20 %) during peak hours. The available flexibility of a resource is thus constrained by its rated power, ramp rates (how quickly it can adjust), and state of charge (for storage systems).

2. Energy Capacity Limits

Beyond instantaneous power, each resource is bounded by the energy it can store or shift: a battery by its usable capacity (kWh) and state of charge, a thermal store by its volume and temperature range, a demand-response action by how long a load can be deferred before comfort or process limits are reached. These energy limits, together with the temporal characteristics, determine which services a resource can credibly offer.

3. Ramp rates and response times

The ability of a resource to respond to a flexibility request is determined by its ramp rate (how quickly it can adjust its power output or consumption) and response time (the delay between receiving a signal and action):

- Fast ramp rates (e.g., batteries) are critical for ancillary services like frequency regulation.
- Slow ramp rates (e.g., thermal storage) are more suited to longer-term planning and seasonal balancing.

Resources with slow ramp rates may require pre-heating, pre-cooling or pre-charging to be ready for activation, which introduces additional complexity in planning and operation.

4. Operational constraints

Flexible resources must operate within system constraints, including:

- Grid constraints: The resource must not overload local networks or violate voltage limits.
- Regulatory constraints: Compliance with grid codes, market rules and environmental regulations.
- Economic constraints: The cost of providing flexibility must be competitive with alternative solutions.
- Other local constraints: Demand side requirements such as user discomfort, user behaviour, appliance availability or process continuity requirements.

5. Data and communication requirements

Flexibility requires real-time data exchange and communication infrastructure to:

- Monitor the state of flexible resources (e.g., battery state of charge, EV charging status).
- Send control signals to activate or deactivate flexibility.
- Verify that flexibility has been delivered (e.g., through metering and telemetry).

This communication is typically enabled by IoT devices, smart meters and centralised control platforms (e.g., aggregator platforms or energy management systems).

Glossary of key terms

To clarify the terminology used throughout this chapter, the following glossary provides definitions for key terms related to flexibility and FaaS:

Flexibility	The ability of a resource to adjust its power output or consumption in response to external signals or system needs across relevant market timeframes. Flexibility can be provided by generation, consumption or storage resources; at system level, the power system's ability to manage variability and uncertainty across timeframes from seconds to years.
Flexibility as a Service	A service framework in which flexibility from generation, storage, demand or

(FaaS)	sector-coupled assets is specified, procured, activated, verified and remunerated through contractual, digital and market layers.
Aggregator	An entity that collects and bundles flexibility from multiple resources (e.g., households, businesses or storage systems) to provide it as a single service to the grid or market. Aggregators play a critical role in enabling large-scale flexibility.
Demand response (DR)	A mechanism where consumers reduce or shift their electricity consumption in response to grid needs or price signals. DR can be price-based (e.g., time-of-use tariffs) or incentive-based (e.g., direct payments for load reduction).
Energy storage system (ESS)	A technology that stores energy for later use, including batteries, pumped hydro, thermal storage or flywheels. ESS can provide flexibility by discharging stored energy during high demand or absorbing excess energy during low demand.
Energy vector	Energy vectors as the carriers that physically link energy systems, namely electricity, thermal and fuels, enabling coordination across infrastructure including water, data and transport networks.
Ramp rate	The speed at which a resource can adjust its power output or consumption. Fast ramp rates are critical for ancillary services, while slow ramp rates are suited to longer-term flexibility.
Ancillary service	Services provided by flexible resources to maintain grid stability, such as frequency regulation, voltage control and black-start capability. Ancillary services are essential for integrating high shares of RES.
Grid constraints	The physical and operational limits of the electricity grid, including voltage limits, thermal limits and congestion. Flexible resources must operate within these constraints to avoid grid instability or outages.
Net-zero energy system	Net-zero emissions energy system is achieved when anthropogenic emissions of greenhouse gases are balanced by anthropogenic removals over a specified period (IPCC, 2018) so that human activity no longer adds to warming. Net-zero CO_2 emissions are also called carbon neutrality. The main issue is to reduce emissions by deploying RES including biomass, energy conservation and efficiency, clean electrification (RES and/or nuclear – direct and indirect (hydrogen) electrification), CCUS, but also remaining emissions are offset through afforestation, direct air capture or soil sequestration (negative emissions).
High renewable energy system (High-RES)	An energy system with a high share of renewable energy sources (e.g., solar, wind) in its generation mix. High-RES systems require flexibility to balance supply and demand, as RES are inherently intermittent and variable.
Congestion management	Actions taken by system operators to relieve overloads of network elements, by redispatching generation, activating flexibility or structurally, reinforcing the grid. In distribution networks congestion is inherently local, which makes locational flexibility particularly valuable.
Prosumer	An end user that simultaneously consumes and produces electricity (e.g. a household or business with rooftop PV), and may additionally store it or offer flexibility to the system, directly or through aggregation.
Virtual power plant (VPP)	A portfolio of distributed generation, storage and controllable loads operated through a common control platform so that it can be dispatched and marketed as a single resource.
Local flexibility market (LFM)	A market-based mechanism through which a DSO procures flexibility services from distributed resources within its network, as an alternative or complement to grid reinforcement.

Energy community	A legal entity, recognized under EU law in several forms (e.g. Renewable Energy Communities, Citizen Energy Communities), through which citizens, SMEs and local authorities jointly produce, share, store or sell energy, with environmental, economic or social benefit, rather than financial profit, as its primary purpose.
Vehicle-to-Grid (V2G)	The bidirectional use of electric-vehicle batteries, allowing energy to be returned from the vehicle to the grid or building in addition to smart (unidirectional) charging control.
Building energy management systems (BACS / BEMS / EMS)	Building automation and control systems and building/customer energy management systems: the digital control layers that monitor and modulate building loads (HVAC, hot water, charging), enabling buildings to deliver flexibility within comfort constraints.
Rebound effect	The partial or full return of consumption after a demand-response activation (e.g. deferred heating or EV charging recovering afterwards). Rebound must be anticipated in scheduling, baselining and settlement, since it reduces the net system benefit of an activation.
Dark doldrums (or “Dunkelflaute”)	An extended period of typically several days of simultaneously low wind and solar output, often combined with cold temperatures, which stresses system adequacy and requires long-duration flexibility resources.
Power-to-X	The conversion of electricity into another energy carrier or product (heat, hydrogen, synthetic fuels), used to absorb surplus renewable generation and couple the power system to other sectors.
Residual load	The net demand that must be covered by controllable resources, i.e. total electricity demand minus generation from variable renewable sources. As the share of wind and solar grows, the residual load becomes more volatile and harder to forecast, driving the need for flexibility across all time horizons.
Curtailment	The deliberate reduction of output from a generation unit (typically wind or solar) below its available production, either for system reasons (over-supply, congestion, frequency) or by market instruction. Curtailment provides dependable downward flexibility; upward flexibility from renewables exists only when plants are already operating curtailed.
Sector coupling	The integration of the electricity sector with heating and cooling, transport, gas, hydrogen and industry, so that demand can be shifted between energy carriers as well as in time. Sector coupling expands the flexibility envelope and reduces balancing costs (e.g. power-to-heat, power-to-hydrogen, smart EV charging).
Explicit flexibility	Flexibility committed and activated against a defined product, instruction or event, so that delivery can be verified and settled. It is the form of flexibility that FaaS contracts and remunerates.
Implicit flexibility	A consumer or asset response to prices or tariffs without a firm dispatch obligation. Valuable, but not interchangeable with explicit flexibility: a probabilistic response to a price signal cannot be counted as a firm reserve unless product rules and verification make it dependable.
Baseline	The counterfactual consumption or generation profile that would have occurred in the absence of a flexibility activation. Delivered flexibility is measured as the difference between metered data and the baseline; baseline methodology is therefore integral to service definition, validation and remuneration (see Chapter 6).
Balancing reserves (FCR, aFRR, mFRR)	The standardised European products for frequency management: Frequency containment reserve (FCR) (activation within 30 s), automatic and manual

	frequency restoration reserves (aFRR/mFRR), each with defined activation times and delivery requirements, traded on pan-European platforms.
Inertia / synthetic inertia	Inertia is the kinetic energy stored in the rotating masses of synchronous generators, which resists frequency changes after a disturbance. Synthetic (or virtual) inertia is a fast power response delivered through power electronics by inverter-based resources to emulate this behaviour.

3.2 Flexibility as a systemic action

Recent literature[18] defines energy system flexibility through three complementary dimensions:

- **spatial flexibility**, enabled by transmission and distribution networks;
- **intraday flexibility**, provided by batteries, demand-side response, and operational load shifting; and hydrogen used as an industrial energy carrier;
- **seasonal flexibility**, ensured by long-duration storage and sector coupling mechanisms. In practice, this category requires nuance: most thermal storage operates on intraday to weekly timescales rather than seasonal ones, and hydrogen's contribution to seasonal storage is conditional on the availability of large-scale underground caverns, as tank-based storage is limited to intraday applications.

This broader perspective highlights that flexibility is fundamentally a coordination problem. The value of flexibility depends less on the isolated technical potential of an asset than on the ability of the system to activate, aggregate, and optimize that flexibility at the right time and location.

Flexibility beyond the electricity sector

A systemic approach requires moving beyond the electricity-only perspective toward an integrated "multi-vector" view of the energy system. Sector coupling between electricity, heating, cooling, gas, hydrogen and mobility creates additional flexibility resources and significantly reduces balancing costs.[19]

Sector coupling includes:

- Power-to-Heat (heat pumps, electric boilers)
- CHP (Combined Heat and Power)
- Power-to-Gas / Power-to-Hydrogen
- hydrogen storage
- smart EV charging and Vehicle-to-Grid (V2G)
- thermal storage in buildings and district heating
- hybrid systems combining generation, storage, and controllable loads

For example, a commercial building equipped with BACS/EMS, heat pumps, thermal inertia, PV generation, batteries and EV charging stations does not simply provide demand response: it becomes an active node of system balancing. Its flexibility contributes simultaneously to congestion management, peak shaving, carbon optimisation, and wholesale market participation.[20]

Multi-actor coordination

Because flexibility is systemic, it requires coordination between actors with different objectives and operational horizons:

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[18] Lund, H., Østergaard, P.A., Connolly, D., & Mathiesen, B.V. (2017). **Smart energy and smart energy systems.** Energy, 137, 556–565. https://doi.org/10.1016/j.energy.2017.05.123

[19] European Parliament (2018).
Sector coupling: how can it be enhanced in the EU to foster grid stability and decarbonise?
Directorate-General for Internal Policies.
https://www.europarl.europa.eu/RegData/etudes/STUD/2018/626091/IPOL_STU(2018)626091_EN.pdf

[20] IEA (2023). **Electricity Market Report 2023**. International Energy Agency. https://www.iea.org/reports/electricity-market-report-2023

- TSOs procure balancing reserves (FCR, aFRR, mFRR) and ensure system-wide frequency stability and adequacy
- DSOs manage local congestion voltage profiles and distribution constraints, increasingly through market-based local flexibility procurement
- suppliers and balance responsible parties optimise portfolio balancing and imbalance exposure
- aggregators pool and monetize distributed flexibility across multiple value streams
- consumers, prosumers and building operators preserve comfort, process continuity and self-consumption objectives.

Flexibility in this sense is distinct from, but complementary to, non-frequency ancillary services such as steady-state voltage control, short-circuit current contribution and inertia for local grid stability [EU Directive 2019/944], which system operators must also secure as synchronous generation retires. This procurement category should not be confused with system inertia at synchronous-area level: because frequency is a variable common to all interconnected systems, dynamic stability is an area-wide concern rather than a local network need[21]. Injection of a frequency stabilization services still need to consider coordination with grid congestion issues. A coherent FaaS framework should therefore be designed so that flexible resources can stack value across both categories where technically feasible, rather than being locked into a single service. Without interoperable governance frameworks and standardised interfaces, the same asset may receive conflicting signals from different actors, thus reducing efficiency or even undermining system stability. This is precisely where the concept of FaaS becomes relevant: it transforms flexibility from a hidden technical potential into an organised service layer that can be activated, contracted, measured and remunerated.

From technical flexibility to service flexibility
Flexibility as a systemic action rests on the technical capability to modulate consumption, production or storage. To become a service, it must be wrapped in the three layers introduced in Chapter 2:

- a contractual layer that defines what is requested and how it is remunerated;
- a digital layer to exchange data and control signals securely and to verify delivery;
- a market layer that values flexibility according to its time- and location-specific worth.

Without these layers, technical potential does not translate into a usable, bankable service.

This systemic vision explains why standards such as interoperable APIs, cybersecurity requirements and validation procedures are becoming strategic enablers of flexibility markets. The challenge is not only to create flexibility, but to make it measurable and bankable.

In this respect, FaaS should be understood as the operational framework that connects technical flexibility to system needs. It is not simply a market product, but a coordination architecture for the future net-zero energy system.

3.3 Time horizons of flexibility (short-, medium- and long-term)

Flexibility must be considered across multiple time horizons, as system needs, activation mechanisms and regulatory frameworks differ significantly depending on whether the objective is immediate balancing, operational optimisation or long-term system planning. In the context of accelerated electrification, increasing renewable penetration and the implementation of the European Green Deal, flexibility is no longer limited to short-term balancing markets: it has become a structural pillar of energy system design.

Recent European legislation reinforces this vision. The reform of the EU electricity market design (Regulation

[21] European Union Agency for the Cooperation of Energy Regulators. (2025). *Methodology for the type and format of the data and for the transmission and distribution system operators' flexibility needs analysis*. ACER. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-flexibility-needs-assessment-methodology-2025.pdf

(EU) 2024/1747 and Directive (EU) 2024/1711), the revised Electricity Regulation, the EPBD recast and the growing development of local flexibility markets all recognise flexibility as a strategic resource for security of supply, affordability and decarbonisation. Similarly, national mechanisms, for example the NEBCO scheme in France, which builds on the earlier NEBEF DR mechanism, illustrate the transition from historical demand response schemes toward broader and more permanent flexibility frameworks.

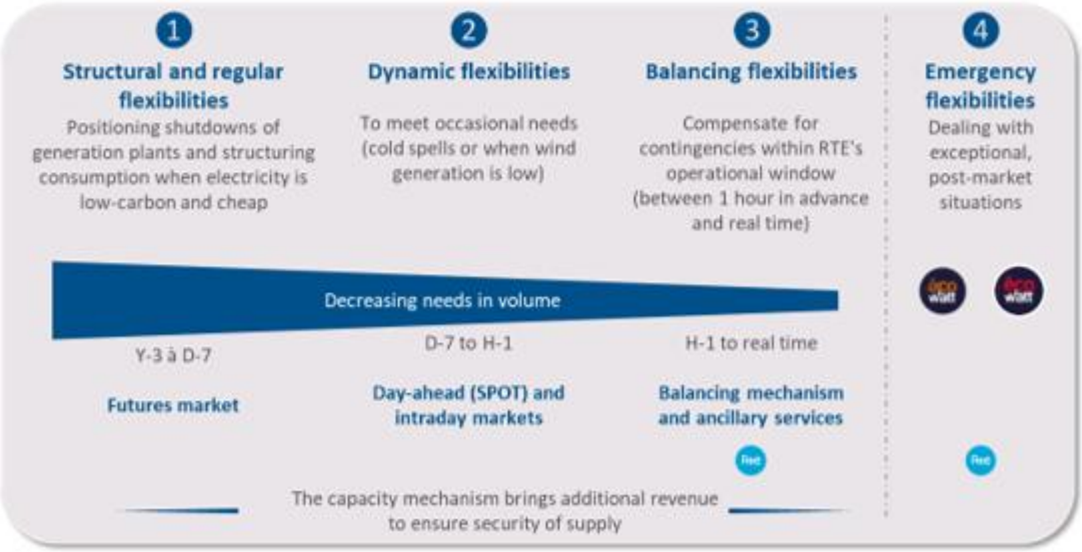

Figure 3 - The four different types of flexibility for supply and demand balance[22]

A FaaS approach must therefore integrate flexibility over three complementary horizons: short-term, medium-term and long-term.

Short-term flexibility: operational balancing and grid security

Short-term flexibility covers timeframes from seconds to intraday operations, typically ranging from frequency response to day-ahead and intraday balancing. Its main purpose is to preserve the real-time balance between generation and consumption and to manage local or national network constraints. This includes:

1. balancing reserves and frequency control, including fast ramping capability from dispatchable assets
2. congestion management
3. demand response activation, including from new flexible loads such as data centres and electrolysers
4. intraday portfolio optimisation
5. local flexibility activation by DSOs

Historically, these services were mainly provided by dispatchable thermal generation. Today, batteries, industrial demand response, smart EV charging, thermal inertia in buildings and aggregated tertiary loads increasingly participate in these mechanisms. For example, a commercial building equipped with a building energy management system (BEMS) can temporarily reduce HVAC consumption during a grid stress event, while an EV fleet can shift charging to avoid transformer congestion at distribution level.

This short-term layer is strongly linked to recent market evolution, particularly the increasing role of aggregators and the opening of balancing services to smaller distributed assets under EU market reform. It is also where interoperability standards and cybersecurity become critical, since activation depends on reliable and secure communication.

[22] Figure taken from: Réseau de Transport d'Électricité (RTE). (2024). *Barometer of demand-side flexibility: Monitoring of the plan to scale up flexibility*. RTE. [Online]. Available: https://assets.rte-france.com/prod/public/2025-08/2024-10-21-barometre-flexibilites-consommation_eng-GB.pdf

Medium-term flexibility: forecasting, optimization and economic valorisation

Medium-term flexibility generally covers horizons from one day to several weeks or months. It focuses on operational planning rather than immediate response, with the objective of optimising energy costs, asset usage and market positioning.

This includes:

- day-ahead and week-ahead optimisation
- seasonal specific thermal storage management
- maintenance scheduling
- flexibility portfolio aggregation
- supplier and aggregator hedging strategies

At this horizon, flexibility is strongly connected to dynamic tariffs, capacity mechanisms and market anticipation. It allows actors to prepare activation strategies based on expected prices, weather conditions, renewable generation and local constraints. For example, a district heating operator may optimise heat production over several days according to electricity prices and renewable availability, while a building portfolio manager may pre-heat or pre-cool assets based on forecasted system peaks.

This layer becomes increasingly important with the deployment of dynamic retail contracts encouraged by EU regulation and with the development of local flexibility mechanisms. It is also central to the economic viability of FaaS, since flexibility revenues are often determined before the actual activation occurs. For aggregators and suppliers, medium-term flexibility is where the business model is mostly built.

Long-term flexibility: structural resilience and investment planning

Long-term flexibility covers horizons from several months to decades and refers to structural decisions that determine the future capacity of the system to integrate renewables and electrified demand without excessive infrastructure costs. This includes:

- grid reinforcement and planning
- electrification strategies
- construction of seasonal storage and balancing (with hydro reservoirs very valuable on this)
- deployment of flexible buildings
- investment in batteries, thermal storage, and hydrogen
- dynamic network tariff and market designs (for example flexibility embedded in home appliances and operated by aggregators via beneficial tariffs) and regulatory reforms
- flexibility-oriented procurement and building requirements.

This dimension is particularly relevant under the EPBD recast, which strengthens requirements for smart-ready buildings, BACS deployment and building interaction with the energy system. Similarly, flexibility is increasingly integrated into network planning strategies to avoid unnecessary grid reinforcement. For example, installing interoperable customer energy management systems (CEMS), thermal storage and EV-charging infrastructure in a commercial building does not create immediate market revenue, but it creates the technical foundation for future flexibility services.

Likewise, the large-scale deployment of compatible systems can be seen as a long-term flexibility infrastructure policy: the objective is not only today’s activation, but tomorrow’s system readiness, as pushed by EU standards such as IEC 62 746-4. Long-term flexibility is therefore closely linked to investment decisions, public policy and standardisation frameworks.

These three horizons are deeply interconnected. A long-term investment, such as installing a battery or upgrading a building automation and control system (BACS), creates the technical capability for short-term activation. Medium-term optimisation determines when this asset should be used and under which economic conditions. Short-term activation then delivers the actual service to the system. Under a systemic perspective, the long-term can be considered as the enabler, the medium-term as the optimiser and the short-term as the activator. Therefore, flexibility can be considered a balancing mechanism, but more importantly, it is a cross-temporal system function that connects infrastructure planning, operational optimisation and real-time activation into a single service model for the future net-zero energy system.

3.4 Role of FaaS in a net-zero and high-RES energy system

The transition toward a net-zero energy system built on high shares of renewable energy sources (RES) fundamentally reshapes the operating logic of European electricity grids. As wind and solar displace dispatchable thermal generation, the ability to balance supply and demand across all time horizons from sub-second frequency response to multi-week seasonal adequacy can no longer rest on a handful of large, centrally dispatched plants. It must be sourced from a broad portfolio of distributed, responsive and commercially organised assets. This is the systemic function that FaaS is designed to fulfil.

In a high-RES system, the residual load, the net demand that must be covered by controllable resources, becomes increasingly volatile and difficult to forecast. It can swing from very high levels to near-zero or even negative within hours, creating both surplus and scarcity events. Prolonged periods of low wind and solar output, sometimes lasting several days across large parts of the continent, create adequacy risks that short-duration batteries or simple demand response programmes cannot address in isolation. Simultaneously, the retirement of synchronous generation reduces the inertia, reactive power support and short-circuit current that grids have historically taken for granted. According to the ENTSO-E report System Flexibility Needs for the Energy Transition (2024[23]), flexibility requirements across all relevant time frames will approximately double between 2025 and 2033. FaaS responds to this challenge by transforming flexibility from an incidental by-product of conventional plant operation into an explicit, contracted and remunerated system service. It creates the institutional, market and technical conditions under which diverse assets: batteries, heat pumps, electrolysers, flexible CHP plants, pumped hydro and virtual power plants can be mobilised, aggregated, and dispatched in a coordinated manner.
Across a high-RES system, FaaS performs four functions that conventional plants used to provide implicitly:

1) **Enabling renewable integration:**

One of the most direct roles of FaaS is to absorb surplus renewable generation that would otherwise be curtailed. In France, RTE (Réseau de Transport d'Électricité[24]) has addressed this through the NEBEF (Notification d'Échanges de Blocs d'Effacement) mechanism, which allows aggregators and large industrial consumers to sell blocks of demand reduction directly into the wholesale market. Large flexible industrial loads such as cement plants, steelworks, cold storage facilities and others can reduce consumption within minutes and be compensated at market rates. A notable participant is Aluminium Dunkerque, one of Europe's largest aluminium smelters, capable of reducing consumption by several hundred megawatts on short notice, offering the grid a flexibility equivalent to a mid-size peaking plant. At the distribution level, Enedis is piloting local flexibility markets through the procuring flexibility from commercial buildings, agricultural cold storage and aggregated residential loads to relieve congestion on medium-voltage feeders, with cost savings exceeding 30% compared to conventional cable upgrades in test cases.[25]

[23] European Network of Transmission System Operators for Electricity (ENTSO-E). (2024). *System Flexibility Needs for the Energy Transition*. ENTSO-E, Brussels. [Online]. Available: https://www.entsoe.eu/system-flexibility/
[24] Commission de Régulation de l'Énergie (CRE). *Effacements de consommation*. Available at: https://www.cre.fr/electricite/reseaux-delectricite/effacements.html
[25] CORDIS project page: https://cordis.europa.eu/project/id/731289

2) **Maintaining frequency stability:**

As synchronous generators retire, the rate of change of frequency (RoCoF) following a fault increases, leaving less time for governors to respond. FaaS must therefore create liquid markets for fast frequency response and synthetic inertia. The frequency containment reserve (FCR) market, co-operated by 12 TSOs across 9 countries in the Continental European Synchronous Area, is one of the most mature examples. Battery storage, responding within 200 milliseconds, well within the 30-second activation window, has progressively displaced gas turbines as the dominant FCR provider in Germany and is growing in France.[26] EDF's battery installations on Corsica[27], combined with wind and solar, already operate the island's grid in near-islanded mode during periods of very high renewable penetration, demonstrating what the continental system will increasingly require.

3) **Cross-vector sector coupling:**

A net-zero system extends well beyond electricity. District heating networks with thermal storage are a particularly powerful source of cross-vector flexibility. Dalkia, a subsidiary of EDF, operates heating networks in more than 80 French cities[28]. By pre-heating networks overnight and drawing down from storage during evening peaks, Dalkia can offer RTE guaranteed load reductions of several tens of megawatts across its portfolio converting thermal inertia into an electrical flexibility service. Hydrogen electrolysis is emerging as another cross-vector resource: France's national hydrogen strategy envisages 6.5 GW of electrolysis[29] capacity by 2030, which, if operated under FaaS-type agreements, could represent several gigawatts of dispatchable demand flexibility.

4) **Long-duration adequacy:**

The most challenging role for FaaS is addressing multi-day adequacy gaps, for example during “Dunkelflaute” events: extended periods of low wind, overcast skies and cold temperatures. The Compagnie Nationale du Rhône (CNR), operating a cascade of 19 hydropower plants along the Rhône with approximately 3 GW of installed capacity, participates in aFRR, mFRR and the French capacity mechanism under agreements with RTE. During the energy crisis of winter 2022–2023, when French nuclear availability was reduced, CNR assets were a critical adequacy resource, illustrating how large hydro under a FaaS framework can serve multiple markets across multiple time horizons simultaneously.

5) **Prosumers and aggregators:**

FaaS also unlocks flexibility from actors previously invisible to system operators. Voltalis, a French company, has installed smart load controllers on more than 200,000 French households[30], representing approximately 1.5 GW of controllable electric heating load. This portfolio is offered to RTE across FCR and aFRR markets, with individual reductions mostly imperceptible to occupants due to building thermal inertia. This is one of Europe's largest residential aggregation programmes and a leading demonstration of how FaaS principles: standardised service specifications, independent aggregation, market-based remuneration can reach assets that conventional grid management frameworks would never access.

As another example, France exploits the flexibility provided by thermal storage by deploying “Time-of-use” electricity tariffs for water heaters. Deployments of electric water heaters alongside ToU tariffs provide the

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[26] ENTSO-E. *Frequency Containment Reserve (FCR) Cooperation*. Available at: https://www.entsoe.eu/network_codes/eb/fcr/

[27] Ministère de la Transition écologique. *Programmation Pluriannuelle de l'Énergie de la Corse (PPEM) 2019–2028*. Available at: https://www.ecologie.gouv.fr

[28] RTE. *Bilan électrique* (annual). Available at: https://www.rte-france.com/analyses-tendances-et-prospectives/bilan-electrique

[29] Ministère de la Transition écologique et solidaire. *Stratégie nationale pour le développement de l'hydrogène décarboné en France*. September 2020. Available at: https://www.gouvernement.fr/sites/default/files/document/document/2020/09/dossier_de_presse_-_strategie_nationale_pour_le_developpement_de_lhydrogene_decarbone_en_france_-_08.09.2020.pdf

[30] Voltalis. *Communiqué de presse — Voltalis clôture le financement de 1,4 GWc de capacité d'effacement pour un montant total de 215 M€*. September 2025. Available at: https://group.voltalis.com/fr/communiques-de-presse/financement-capacite-effacement-215-me-7954

possibility of flattening the household demand curve. Consumers see savings in electricity bill by switching on the water heater during off-peak periods. Using an on/off control, they shift the demand of their electric water heaters to off-peak periods, flattening the demand curve and easing stress on the power system.
Taking it further, aggregators in the future (and in some countries already, like the UK) offer the option to switch on/off domestic appliances in exchange for a beneficiary tariff.

Aggregators in particular have a big role to play in FaaS. Controlling a wide portfolio of small-scale consumers or producers of energy for heating or cooling, they can lower costs, maximise efficiencies and provide valuable flexibility services to system operators. The aggregator remotely controls the clients' appliances on their behalf, aiming to maximise the efficiency of their use and minimise the clients' energy expenditure.

- ***Clients:*** Households which allow the aggregator to control their appliances
- ***Benefit for aggregator*****:** Creation of a virtual power plant which can compete in the electricity market (Demand Response) and provide grid flexibility services.
- ***Benefit for clients:*** By having the use of the appliances optimized by the aggregator, the clients are able to see substantial benefits in their utility bills.
- ***Why aggregator:*** The flexibility that individual heat pumps or rooftop solar arrays can provide is far too limited to have an impact on the grid. However, aggregating many units together creates a major source of flexibility that can be marketed to grid operators.

For example, in Belgium, demand response operations using 40 000 residential heat pumps can provide 100 MW of upward reserve at a cost of EUR 0-14/MWh, lower than the local historical price of EUR 32/MWh offered conventional reserves (Georges et al., 2017). FaaS is therefore not an optional complement to the energy transition. It is a structural prerequisite for a net-zero, high-RES system that is simultaneously reliable, affordable and decarbonised. The Electricity Market Regulation (EU) 2024/1747 requires Member States to carry out regular flexibility needs assessments and enables them to establish non-fossil flexibility support schemes, creating the regulatory foundation on which FaaS must now be built at scale. Member States differ widely in their flexibility equipment, so deployment paths will vary, but the regulatory direction is now common across the EU.

4. PORTFOLIO OF FLEXIBLE ASSETS AND RESOURCES

A portfolio of flexible power generation assets and storage devices is needed to respond quickly to changes in electricity residual demand, grid congestion management, spinning reserves, supply of ancillary services and resilience as described in the introduction. Since many of these services should preferably be located near where constraints occur, or near the cause of disturbance, a priority for distributed / localised flexibility resources is essential. To preserve energy efficiency, a sector coupling perspective of these resources should also be prioritised. For example, if a flexible power generation unit creates a waste heat stream, then that heat could be used for process heating or district heating, possibly enhanced by using thermal heat storage. The need for a flexible resource for grid services to be localised often goes hand in hand with the need for localisation to enable waste heat capture.

Not all flexible resources need to be able to respond in the fastest time frames of parts of seconds. Neither is it reasonable, or even possible, to allow a many-hour discharge time for all flex resources. But, by having slightly more fast-responding capacity than the shortest time frame strictly requires, these fast resources can assist such resources that are otherwise too slow and contribute usefully. The fact that different types of flex resources have different characteristics and different economic time windows of dispatch presents an opportunity for a more optimal structure by blending resource types in the system than by using just one type of resource.

At a high level, for power balancing, flexibility resources can be divided into flexible dispatchable power generation, including flex-CHP and energy storage (see chapter 4.1) and demand-side management, demand-response and consumer-centric flexibility (see chapter 4.2).

These groups present somewhat different characteristics; power generation can operate continuously; increased duration of operation is just at an added running cost of fuel (fossil or renewable origin). Energy storage saves electricity from the grid for later dispatch and has fast activation, but suffers from limited duration where an increase in duration comes at added investment for storage size. Demand response comes at very low cost when it is just a recovery of energy use, but it is typically limited to within day-scale due to the demands of energy users. Demand response by temporarily reducing or stopping industrial production is however a costly option to use as a last resort.

Examples of flexible power generation assets, detailed in 4.1, include gas-fired peaker plants, including gas engines and turbines, which can start and stop rapidly to meet sudden spikes in demand in power or other services. Combined cycle gas turbines including hydrogen gas turbines are another example, offering both high efficiency and fast response times. Hydroelectric plants, particularly those with pumped storage capabilities, can store energy and release it when needed, acting as both generators and reservoirs. Battery energy storage systems are increasingly important, enabling storage / time-shift of excess electricity and contribution to frequency balancing. V2G solutions are expected to contribute significantly in future; already today vehicle charging is to some extent managed as demand response. Throughout this chapter, each resource class is described from its physical and economic characteristics and, specifically, by how flexibility can be made available as a service. Table 1 maps the main resource classes to their response time, usable duration and the time horizons introduced in Chapter 3.

Table 1 - Indicative mapping of flexible-resource classes

Resource class	Response time	Usable duration	Time horizon	Primary FaaS services
Flexible thermal and CHP	minutes (gas engines <3–5 min)	fuel-limited, sustained	short–long	residual load, reserves, inertia, black-start
Reservoir and pumped hydro	seconds–minutes	hours–seasonal	short–long	balancing, reserves, inertia, adequacy
Batteries (Li-ion / LFP)	< 1 s	typ. 1–4 h	short (sub-second–intraday)	FCR/aFRR, peak shaving, congestion, voltage
Long-duration storage (CAES, LAES, thermal/Carnot, H_2)	seconds–minutes	many hours–days/seasonal	medium–long	multi-day balancing, adequacy, Dunkelflaute
Demand response – buildings/HVAC	minutes	minutes–hours (comfort-limited)	short–medium	peak shaving, congestion, balancing
Demand response – industry	minutes	process-limited	short–medium	reserves, peak, large-volume balancing
EV smart charging / V2G	seconds–minutes	hours (availability-limited)	short–medium	congestion, balancing, local support
Electrolysers / power-to-X	seconds–minutes	demand/storage-limited	medium–long	surplus absorption, cross-vector, long-duration
Aggregation / VPP / energy communities	inherits underlying assets	inherits underlying assets	all	makes small assets market-relevant (see Ch.7)

4.1 Generation and energy storage-based flexibility

There is always a need for a merit order so that the most efficient resources are prioritised. Considering that renewable wind and solar generation may exceed the total demand, the first action is to charge storage systems as much as possible and only thereafter curtail (shut down) part of the renewable power generation. When the share of renewable generation in the system is moderate, this is not requested, and therefore, many existing solar and wind generators lack automated responses to over-supply situations except for trip circuits that react to excessive voltage. Future assets will need to be actively controlled to a larger extent to avoid frequency and / or voltage disturbances; for wind farms and very large PV installations this is less of an issue than for small-scaled PV.

Furthermore, when the demand is greater than the supply from wind and solar, hydro and energy storage discharge come into play. The dispatch order between these resources may be a strategic game to minimise the energy supply needed from the last categories of thermal power that is finally dispatched when power capacity or energy content of renewables plus storage approaches the limits.

Since thermal power generation will be last in dispatch order, the flexibility requirements for load variations as well as for frequent starts and stops are expected to increase with the increasing share of renewables. However, the situation will be more complex than the provision of flexible residual load. There will be situations where thermal power generation will be required to handle grid congestion even if there is ample supply of renewable power. For example, if a region has a large share of PV power at a certain instant, then voltage control need to be handled and possibly also short circuit capability needs to be provided. When there is a high share of renewable power in dispatch systems, some injection of inertia might be needed to keep the system stable. Ideally, a thermo-mechanical storage can provide both: balancing and system stability services (e.g. with rotating inertia). Of course, only if the storage is sufficiently charged.
The future role of thermal power generation can be structured into the following four different groups:

1.1 **Residual load provision,** power supply being managed through a number of marketplaces, day-ahead and intraday, split up in different time frames spanning from frequency stabilization in second frames up to weeks.
2.1 **Grid congestion management** which will be difficult to handle through marketplaces since it is a local issue where localised power supply is needed. Compensation for these services will probably best be by agreements between DSO and power plant operators and secondly between TSO and DSO.
3.1 **System services,** of which inertia [31] is a synchronous area-wide issue, since frequency is a variable common to all interconnected systems, whereas voltage control is to a large extent a local issue that is also growing by the increased connection of solar PV. The ability to supply short circuit current is also to large extent a local issue; a proper distribution of this ability should be governed so that it is sufficient for any short circuit event at any position in the grid at all times.
4.1 **Resilience and ability to restore grid operation** are qualities that one would prefer never to have to use, but which must be present to a sufficient degree to ensure that, in the event of a blackout, the consequences are minimised and normal operations are restored relatively quickly. The emergency power supply is also an essential component of this category.

The ability to switch automatically to island-mode operation or to black-start directly into island mode is particularly important for critical infrastructure. One example is the continuous operation of an industrial CHP plant, even where most process heat is supplied by electrified heating. If the grid connection is lost, the CHP can remain online, the electrified heating can be adjusted and the plant can immediately transition to island mode. The CHP then ramps up rapidly and takes over both power and heat supply. In sensitive industries, this is already an established strategy. In some cases, the CHP load is continuously balanced with internal demand so that a transition to island mode does not require any additional load increase. Once in island mode, the plant must also be capable of absorbing sudden load changes, for example, when additional industrial sites or districts are connected as the power island expands. When reconnecting the island to a neighbouring island or to a restarted main grid, phasing equipment must be installed at strategic breakers to prevent unsafe closing operations.

A well-distributed set of local emergency reserve generators, with some units spinning and others ready for fast start can address upstream transmission faults while reducing the need for redundancy in the transmission grid. Localised reserves therefore offer an efficient way to increase the usable capacity of existing transmission infrastructure without compromising redundancy, because part of the normal N-1 requirement is covered by reserve generators rather than by grid-side reserves. These reserves must be capable of sustained operation, such as thermal generation or hydropower with large reservoir capacity. Where local storage systems are available, they can bridge the time until standby generation starts, reducing the required amount of spinning reserve and saving fuel or water by allowing more units to remain in standby mode. The key difference between covering the grid N-1 requirement with spinning reserve and managing grid congestion is that N-1 reserves are dispatched only in response to a grid fault, whereas congestion management requires active power dispatch downstream of a grid bottleneck.

Generation technologies and flexibility features

Different technologies offer varying levels of operational flexibility and differ significantly in their economic characteristics. Technologies with high capital costs but low operating costs need to run at high output for as many hours as possible to remain economically viable — for example, nuclear power plants, wind and solar. In contrast, technologies such as single-cycle gas turbines or gas engines, which have relatively low investment costs but high operating costs, are better suited for applications that require high capacity but fewer operating hours. A well-balanced mix of different resources within the energy system enables each technology to be used

[31] ACER. (2025). *Flexibility Needs Assessment Methodology*. Ljubljana: European Union Agency for the Cooperation of Energy Regulators. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-flexibility-needs-assessment-methodology-2025.pdf

optimally, and with an effective market design, this balance should emerge naturally over time. Efficient information exchange between resources, combined with accurate forecasting, will be crucial for avoiding unnecessary costs and improving overall energy efficiency. The table below provides examples of technologies and their technical flexibility features. Aspects of individual generation technologies are further discussed in appendix 9.1 (Description of generation technologies).

The tables below are intended as qualitative orientation tools rather than exhaustive technical specifications. Generation technologies are stand-alone technologies; no hybrids are considered. They should be read across rows and columns: rows refer to flexibility features or technology capabilities, while the columns indicate the most important generation technologies. The symbols used in the technology comparison table provide a relative assessment only: “++” indicates a very strong fit, “+” a strong fit, “0” an average or context-dependent fit, “-” a weak fit, and “- -” a very weak fit. An empty field means non-applicable fit. These ratings are indicative and may vary depending on plant design, operating strategy, grid location, fuel availability, market rules and contractual arrangements. The purpose is therefore to support comparison between flexibility options and to highlight which resource types are best suited for specific services, timeframes and system needs.

Table 2 - Qualitative orientation to analyse operational capabilities of generation technologies.

Features / Capabilities \ Generation technologies	Wind (onshore / offshore)	Solar PV (+inverter)	Solar CSP	SCGT	CCGT	Reciprocating engines	Hydro power dispatchable using a dam	Hydropower continuous using running water	Geothermal plants	Conventional power plants (coal, biomass)	Nuclear power plants	Fuel cells power plants
Specific CAPEX	-	0	-	+	0	++	- -	0	0	-	- -	+
Specific OPEX	++	++	++	-	0	0	++	++	++	- -	+	0
Availability	-	- -	-	+	+	+	+	0	+	+	+	++
Reliability	++	++	++	++	++	++	++	++	++	++	++	++
Efficiency (electric / fuel input)				0	++	+				0	-	++
Suitability for CHP application			++	++	++	0			++	++	+	0
Suitability for frequent start/stop			0	++	0	++	++	++	++	-	- -	0
Ramp rate / load follow operation				++	+	++	++	0	0	0	+	+
Start-up time			++	++	+	++	++	++	+	+	-	0
Part-load operation / minimum load			+	+	+	++	++	++	+	+	+	++
Efficiency at part-load (electric / fuel input)				-	+	+				0	-	++
Overload capacity (dispatchable)			+	0	+	0	0	0	+	0	+	++
System restoration / black start capability			-	++	++	+	++	++	+	+	-	0
Island mode			+	++	++	+	++	++	++	++	0	0
Rotating inertia	-	- -	+	+	++	0	+	+	+	++	++	- -

Table 3 - Explanation of operational capabilities

Features	Explanation
Spec. CAPEX	Capital expenditure per MW installed. It is typically used for EPC and owners cost of an investment.
Spec. OPEX	Operational expenditure per MWh generated. It includes all operational cost such as service and maintenance, commodities, operation and fuels.
Availability	Percentage of the actual operating time (specified operating time – preventive and corrective maintenance) relative to the specified operating time.
Reliability	Percentage the actual operating time (specified operating time – corrective maintenance) relative to the specified operating time
Efficiency (electric / fuel input)	Depending on technology: power-to-power (p-t-p), fuel-to-power (f-t-p) or mixed
Suitability for CHP operation	Operational flexibility for combined heat and power production (CHP)
Suitability for frequent start/stop	Time required from standstill to full load operation.
Ramp rate / load follow operation	Power ramp up or power ramp down capability in MW/min
Start-up time	Time period to bring a generating technology from an offline or idle state to a synchronised state where it actively supplies electricity to the power grid.
Part-load operation / minimum load	Running a generation unit at any output level below its maximum rated (or "full load") capacity
Efficiency at part-load (electric / fuel input)	Measures how effectively the plant converts fuel into electricity when operating below its maximum design capacity (nominal load)
Overload capacity (dispatchable)	A power plant's ability to safely exceed its power rating (nameplate capacity) for a short, specified period upon the request of a grid operator.
System restoration / black start capability	Technologies that can start on their own without depending on the external power supply from the grid and restore grid parallel operation
Island mode	The capability of a power generator to operate without being connected to the main grid.
Rotating inertia	The stored kinetic energy in the heavy spinning rotors of traditional generators

Separate energy storage systems

A wide spectrum of energy storage solutions is available and undergoing further development, each tailored to distinct grid services and market needs. The diagram below shows a few storage technologies and indicates different capacities.

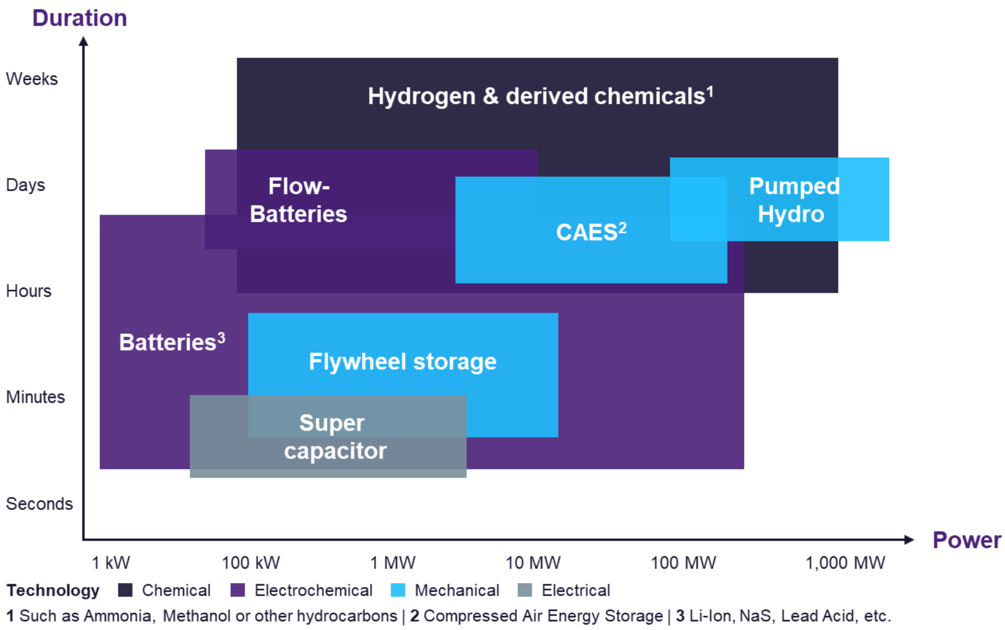

Figure 4 - Portfolio of different storage technologies for different applications [Siemens Energy]

Energy storage systems are characterised by operation within limitations in both power capacity and stored energy content expressed as duration at full capacity. They also have a certain activation / start-up time.
The cost of dispatched energy from an energy storage system is basically built up by:

- Cost of energy input is divided by roundtrip efficiency to find dispatch energy cost contribution.
- Capex cost distributed over each utilised cycle

O&M cost largely related to cycle wear, e.g. current lithium-iron-phosphate (LFP) cells reaching end of life after roughly 6000 cycles at 80 % depth of discharge[32]. To make sound use of capital invested in the storage system, one needs to size the system such that the full capacity in both power and energy content is used at a rather high number of events across a normal year. Sizing power and energy capacity of storage systems to cover worst case scenarios is not economic; remaining demand is better serviced by other resources like thermal power.

If capital cost is distributed over discharged energy (€/kWh) the cost will escalate rapidly by increased duration due to rapid reduction of frequency of the events that call for the last addition. The simplified diagram below shows how energy cost from a storage solution depends on duration capacity. Initially, the specific energy cost is reduced by increasing duration capacity through better use of the infrastructure unaffected by energy content, e.g. inverter and step up transformers. Up to a certain duration, e.g. 2 hours, the number of used cycles is not affected much, but then at increased duration, capital cost per cycle increases exponentially due to the reduced number of used cycles and gradually begins to dominate the dispatch cost. At a certain duration capacity, the storage system energy cost becomes larger than the marginal cost of more operation hours for other technology operated in the same grid, e.g. a gas turbine operated on H2 from pipeline. To ensure a profitable business, the storage should thus be sized to less capacity than such a breakpoint. All storage technologies show this type of cost curve but at different breakpoints in duration. Extending duration from, e.g. 4 to 8 hours, may mean that the last addition is used only weekly instead of daily, i.e. use reduced by factor 7. If we go to the extreme of more than 2 weeks duration resulting in full use only once per year, it can easily be deducted that we can only accept investment cost for last addition in the range of 2 – 5 € per kWh (stored), maybe even less since also other cost-elements needs to be covered.

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[32] Jasper, F. B., Späthe, J., Baumann, M., Peters, J. F., Ruhland, J., & Weil, M. (2022). *Life cycle assessment (LCA) of a battery home storage system based on primary data*. Journal of Cleaner Production, 366, 132899. [Online]. Available: https://doi.org/10.1016/j.jclepro.2022.132899

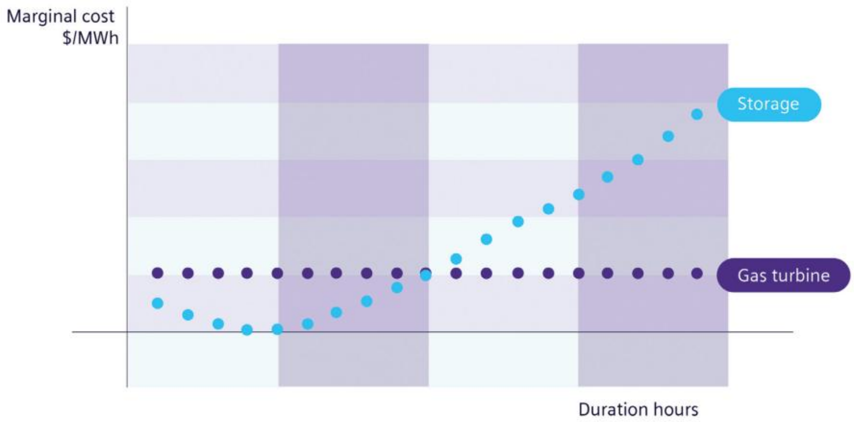

Figure 5 - Typical escalation of dispatch cost from storage solutions by increasing duration [33]

A simple example that demonstrates the limitations of storage duration may be the following: Assume that we wish to use battery storage to supply one GW power for 2 weeks duration, and that 2 MWh of Li-Ion battery capacity is installed per container, then 168 000 containers would be required for the battery. If the containers were installed in a row, occupying a length of 20 m each including electric gear etc., then the row would be 3 400 kilometres long. This tells us that even with zero battery cost it is not physically possible to construct BESS for such durations as long as weeks.

Notably, energy storage assets are increasingly deployed in competitive wholesale markets. The main driver behind this is frequency stabilisation services, i.e. trade from cheap to expensive periods is just a part of the value added. Localised storage can contribute significantly to congestion management and voltage stabilisation too. Localised energy storage combined with localised generation is an efficient way to better use grid infrastructure, and also for the long term, since peaks and voltage stabilisation services are handled locally and do not burden the grid. Grids can then be dimensioned more for the average load than for worst cases. The following table highlights the different characteristics of various storage technologies. All technologies are compared on the basis of a defined LDES scenario: power 100 MW, discharge time 10 hrs, charge-discharge ratio 1:1.

[33] Siemens Energy, article in *The Energy Industry Times*, September 2021.

Table 4 - Qualitative orientation to analyse operational capabilities of storage technologies.

Storage technologies* / Features / Capabilities	Batteries (Li.-ion, NaS, lead acid, …)	Flow batteries (organic / inorganic)	Pumped hydro energy storage	Compressed air energy storage CAES	Liquid air energy storage LAES	Pumped heat energy storage PHES / Carnot batteries	Thermal storage (salt, metal stone, …) with re-electr.	Super capacitor	Flywheel
Specific capacity CAPEX**	+	+	+	++	-	--	-	++	-
Specific power CAPEX**	+	+	-	+	-	--	-	--	-
Specific OPEX**	++	++	+	+	+	++	+	++	++
Roundtrip efficiency	++	+	++	+	-	+	-	n/a	n/a
Response time	++	++	+	0	0	0	-	++	++
Flexible design of charge-discharge-ratio	0	0	0	++	++	++	++	--	--
Ramp rate	++	++	+	+	+	+	+	++	++
Minimum load	++	++	+	+	+	+	+	--	--
Rotating inertia	--	--	++	++	+	+	+	--	++
Black start capability	++	++	++	+	+	+	0	--	--
Grid balancing	++	++	++	++	++	++	++	--	--

* Chemical storage / seasonal storage not considered due to multiple re-electrification options (FC, gas engine, gas turbine, …)

** Only CAPEX and OPEX for overground equipment considered

Table 5 - Explanation of operational capabilities

Features	Explanation
Spec. capacity CAPEX	Capital expenditure per MWh installed capacity. It is typically used for EPC and owners cost of an investment.
Spec. Power CAPEX	Capital expenditure per MW installed. It is typically used for EPC and owners cost of an investment.
Spec. OPEX	Operational expenditure per MWh generated. It includes all operational cost such as service and maintenance, commodities, operation and fuels.
Roundtrip efficiency	Percentage of energy recovered from an energy storage system (such as a battery) relative to the total energy initially put into it.
Response time	Duration of an energy storage system for adjusting its power output or transition from zero to 100% of its rated power upon receiving a control signal.
Flexible design of charge-discharge-ratio	System configuration where an energy storage charging speed and discharging speed can be adjusted independently.
Ramp rate	This is the power ramp up or power ramp down capability in MW/min.
Minimum load	Minimum operating threshold.
Rotating inertia	The stored kinetic energy in the heavy spinning rotors, e.g. of traditional generators.
Blackstart capability	Technologies that can start on their own without depending on the external power supply from the grid and restore grid parallel operation.
Grid balancing	The continuous process of matching electricity supply with consumer demand in real time.

Hybrid technologies combining generation and energy storage (few examples)

1) **Integration of BESS in solar PV installation.**

A BESS integrated with a solar PV installation can provide the same services for balancing solar and other grid variations as a separate BESS. However, there are some added benefits from combining the systems:

- Reduced investment by using a common inverter system for both PV and BESS through a connection at the DC side.
- Improved cycle efficiency as DC supply from the PV system can be used for charging without conversion to AC and back to DC.
- Time-shift of energy behind the meter avoids transfer of energy through the grid and reduces the impact of both PV supply variations and own load variations to the grid.
- Fewer voltage disturbance issues otherwise caused by PV installations by reactive power compensation and by absorption of power in situations where otherwise PV alone could cause local oversupply.

2) **Integration of BESS in wind power installation.**

A local BESS can contribute to the provision of system services by a wind farm, e.g. reduce the issue that the synthetic inertia provided leads quickly to loss of power when wind turbines alone are used for such a service. When there are more abrupt variations in power dispatch by a wind farm, a BESS can also assist in smoothing a steep change into a load ramp that is easier compensated for by other resources in the grid.

3) **Integration of complementing power generation in wind power installation**

By combining a wind farm with other assets that can provide residual load, the wind generation variations are compensated directly at the source. If a storage system, preferably of long duration type, is used for this purpose the grid connection can be sized smaller, without needing to transfer the peak generation capacity of the wind farm. If a thermal power plant is also integrated in the solution, the power sales from the wind farm can be committed as fully dispatchable and thereby all supplied energy can be sold at a higher value with no risks of cost or penalties for balancing power due to forecasting errors.

4) **Integration of BESS in thermal power generation.**

A BESS system combined with a thermal power plant can share some resources, e.g. step-up transformer and grid connection interface with the power plant. In addition to all normal grid services, free-standing BESS systems can boost the power plant's capabilities. Examples of this are:

- improving power ramp rate,
- bridging start-ups time of steam turbine,
- providing required spinning reserve (and thereby allowing the power plant to be used better),
- replacing needs for internal standby or black-start power,
- assisting in compensating power capacity drop at high ambient temperature,
- assisting load jumps in Island mode extension (when closing breakers for connection of users).

5) **Integration of high temperature energy storage in power generation cycles**

By integrating a high temperature storage solution, steam produced when discharging can be fed to a steam turbine which would already exist anyway in a thermal power plant, e.g. a combined cycle installation. Then the investment is significantly less than if a separate store system with dedicated re-electrification systems is constructed, which unfortunately is expected to be a poor business case. A second benefit is that when the storage system is nearly empty, the thermal plant can be started to take over dispatch, and a start cycle for the steam turbine and related systems is avoided.

A further benefit, and thereby even better business case, is found when the integrated storage system is implemented in a CHP configuration, whereby waste heat from storage discharge, after electricity production in the steam turbine, is used for process heat supply. Thus, time shifting renewable energy for electrified heating solves residual heat demand in periods of lack of renewable power whilst also delivering residual load to the grid. Thermal storage is also useful as part of other thermal-mechanical storage systems like A-CAES, EnergyDome (sCO_2), PHES or as Power-2-heat-storage for industrial heat use.

From a FaaS perspective, the takeaway from this section is that no single resource class covers the full spectrum of services and durations: fast but energy-limited storage, slower but sustained thermal generation, and hybrid configurations each occupy a distinct techno-economic niche. The service framework introduced in Chapter 3 is precisely what allows these heterogeneous capabilities to be specified, compared and procured on common terms. The operational and market chapters that follow (5 and 7) describe how that happens in practice.

4.2 Demand-side management, demand-response and consumer-centric flexibility (Buildings, DHC, industry, ...)

As electrification advances and generation follows the weather, demand becomes a main driver of the net load the system has to balance: buildings, mobility and industry increasingly determine when and where the grid is under stress. Demand-side flexibility thus belongs in a FaaS framework, provided it is treated as a service that can be contracted and settled, and not as an emergency measure invoked when the system runs short.

Automated, standardised demand response has been operating for over a decade, but FaaS adds the contractual and continuous participation: the response is agreed in advance, activated automatically and settled against a measured baseline, so that a distributed and behaviour-dependent resource can be procured alongside generation and storage. This requires each product to be defined precisely enough to be verified. A flexibility product specifies its power, duration, activation window and performance requirements before delivery; it is activated through digital control and real-time communication; its delivery is checked against an explicit baseline; and its performance is assessed afterwards, accounting for under-delivery, rebound and sustained response. Baseline uncertainty still weighs on demand relative to metered supply, so procurement alongside generation does not yet mean procurement on identical terms. The sections below trace where this flexibility physically arises, sector by sector.

Buildings and tertiary sector
Buildings are among the largest and most scalable reservoirs of demand-side flexibility. HVAC systems, domestic hot water and the thermal inertia of the building fabric can absorb or shift electrical demand over intra-day and daily horizons. Where a building is equipped with advanced BACS or a BEMS, this flexibility can be delivered with little or no perceptible impact on occupants, and, once aggregated, offered as a service at distribution level. Under FaaS, the unit of control is not the individual asset but the portfolio: each building's comfort and operational constraints are embedded directly in an aggregated optimisation problem, rather than negotiated appliance by appliance.

Two business models illustrate how this reaches the end user. In the aggregation model, a provider pools thousands of residential loads, heat pumps, water heaters, refrigerators and EV chargers into a virtual power plant that shifts or curtails demand in response to grid conditions, returning value to the consumer as lower bills and, where local generation is present, higher self-consumption. The Swiss aggregator *tiko* built one of Europe's largest such plants, controlling roughly 100 MW across more than 7,000 households, before its Swiss consumer operations ended in early 2025[34]. In the heating- or cooling-as-a-service model, by contrast, the provider owns and operates the equipment (heat pump, boiler, chiller) and sells the service, heat, hot water, or cooling, rather than the hardware. This removes the upfront investment and the maintenance risk for the consumer, while giving the provider operational data, an incentive to run the asset efficiently and a recurring revenue stream. Suntherm in Denmark, for example, installs and remotely operates residential heat pumps at no upfront cost, optionally coupling them to rooftop PV, with the customer paying for the service over time[35].

District heating and cooling (DHC)
DHC networks add a further layer of flexibility through thermal storage and sector coupling. Electric boilers, large heat pumps and thermal storage tanks let electricity-to-heat conversion be shifted over hours or days, which makes DHC well suited to medium-duration flexibility, RES integration and cross-vector optimisation between the power and heat sectors. The value such systems provide cannot be read off electrical indicators alone: it depends on thermal dynamics, storage state and the obligation to maintain service continuity.
Taarnby, near Copenhagen, is an instructive case. Commissioned from 2020, it was among the first systems to combine district heating and cooling with wastewater heat recovery, ground-source cooling and a cold-water

[34] Energy Solutions. (n.d.). *tiko – virtual power plant for residential flexibility*. [Online]. Available: https://tiko.ch
[35] Suntherm. (n.d.). *Suntherm – heat pump solutions*. [Online]. Available: https://suntherm.dk/

storage tank. Four ammonia heat pumps (≈ 6.5 MW heat, 4.5 MW cold), driven largely by low-cost electricity, deliver the district cooling and feed heat into the existing network, which continues to be supplied mainly by cogeneration, waste and gas. The 2,000 m³ storage tank decouples heat-pump operation from instantaneous demand, allowing the plant to follow electricity prices[36],[37].

Other sectors: industry and electric mobility

Industrial demand response typically offers large volumes of flexibility but is characterised by tight operational constraints and strong dependence on production schedules. Flexibility may arise from process rescheduling, controllable auxiliary loads or hybrid configurations combining electricity, heat and storage.

In this sector, FaaS shifts the focus from *ad hoc* participation to contracted flexibility services, where industrial actors can establish explicit boundaries of participation and delegated control.

Electric vehicles represent a rapidly expanding source of distributed flexibility. Smart charging, load shifting and V2G enable electric mobility to contribute to both short-term balancing and local congestion management. However, the reliability of this flexibility depends on user behaviour, charging availability and aggregation scale, which reinforces the need for portfolio-based FaaS solutions.

From aggregation to system resource

Demand-side flexibility differs from supply-side resources because it is provided by many small, heterogeneous and behaviour-dependent loads, making its availability inherently uncertain. For this reason, individual assets are rarely able to deliver reliable system services on their own. Aggregation is therefore essential for transforming fragmented demand-side potential into dependable flexibility by smoothing variability, reducing delivery risk and managing rebound effects at portfolio level. In this framework, aggregators play a central role by coordinating resources, forecasting response and assuming responsibility for service performance.

A specific concern the aggregator must manage is the rebound (or payback) effect: load deferred during an activation returns once the event ends, and if many assets recover simultaneously the portfolio can produce a secondary peak that erodes or reverses the flexibility just delivered. Staggering and randomising re-activation across the portfolio is therefore not a detail but a condition for the service to be net-beneficial.

Energy communities represent a local form of aggregation with real value at distribution level, supporting congestion relief and peak reduction, and, where inverter-based resources are present, contributing to voltage management. Managed this way, demand-side flexibility ceases to be a consumer incentive scheme and becomes a system resource whose value lies in both reducing consumption and reshaping it across time and location to match system needs. In this sense, it should be provided that its delivery is verified through consistent baselines and remunerated on the value actually delivered rather than the theoretical potential.

4.3 Flexibility from data centres and hydrogen

4.3.1 Hydrogen Production via Electrolysis

Hydrogen production via electrolysis is viewed in Europe as a flexibility solution for the energy system and is expected to grow significantly in the next few years. The figure below illustrates the projected growth in hydrogen production through 2050.

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[36] Copenhagen Centre on Energy Efficiency (C2E2). (n.d.). *Taarnby – Smart combination of district cooling, district heating and waste water*. Copenhagen: UNEP Copenhagen Climate Centre. [Online]. Available: https://c2e2.unepccc.org/kms_object/taarnby-smart-combination-of-district-cooling-district-heating-and-waste-water/

[37] ETIP SNET. (2022). *Coupling of Heating/Cooling and Electricity Sectors in a Renewable Energy-Driven Europe*. Brussels: European Technology and Innovation Platform Smart Networks for Energy Transition. [Online]. Available: https://smart-networks-energy-transition.ec.europa.eu/publications/etip-publications

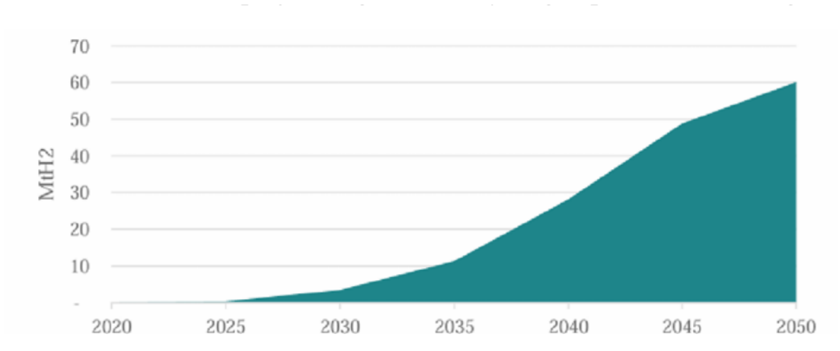


Figure 6 - Projected growth in hydrogen production via electrolysis in Europe through 2050

The most common categories of electrolysers are PEM (Proton Exchange Membrane type of Electrolyser) and ALK (Alkaline Water Electrolyser). Alkaline electrolysers represent the most mature and cost-effective technology. However, due to their high inertia, they lack the ability to respond quickly to grid commands. Response speed to grid commands is improved in smaller ALK electrolyser systems. Conversely, PEM electrolysers are considered ideal for dynamic and rapid operation as they can quickly adjust their output according to grid needs. For these reasons, bigger plants are often chosen which incorporate both PEM and ALK electrolysers, thereby leveraging the advantages of both technologies.

The first and arguably most significant contribution of hydrogen to grid flexibility is its use as a storage technology for excess electricity generated by renewable energy sources (primarily solar PV) during midday hours. Specifically, electrolysers increase their consumption during hours when generation far exceeds demand, converting the excess electricity into H2 and using it during evening hours when the system needs it. At the same time, it can reduce the need for costly redispatch actions caused by grid congestion and system imbalances. This specific function of electrolysers offers the TSO a solution for using surplus energy that was previously curtailed. Smoothing the demand curve enables the integration of more renewable energy technologies, making investments more attractive and preventing price cannibalisation in the electricity market.

Furthermore, the ability to vary the load operating range provides flexibility to the grid. Specifically, electrolysers can operate at their technical minimum capacity, which, depending on the technology, ranges from 10% to 40%. The remaining 60-90% of the electrolysers' electricity consumption can therefore be adjusted, enabling the creation of significant flexible demand capable of responding to the system's needs. This specific advantage can be leveraged by maximising consumption during hours of high renewable energy production, when demand is low, and reducing it accordingly during peak hours.

Also, overloads (going above nameplate capacity) above 100% become technically and economically feasible mainly at larger scales, where the additional CAPEX for upgraded power electronics and balance-of-plant can be justified. They can be achieved for a short time window – followed by a mandatory lower power cooling period. It is intentionally used to capitalise on "peak" power from wind or solar that exceeds the electrolyser's nominal rating, further reducing the need to curtail (waste) energy. This can also be used to contribute to grid stability, by drawing excess power to mitigate overvoltages in the grid during periods of high renewable generation.

The dynamic response characteristics of electrolysers further determine their capacity to participate in fast-acting flexibility services:

- **Start-up times:** warm start-ups can range between 1 and 10 minutes, depending on the technology. Cold start-ups vary from 10 mins in the case of PEM, to ~1 hour for alkaline electrolysis.

- **Ramp rates:** large-scale industrial systems typically feature ramp-rates of 1-10%/s, depending on technology and size, once operating conditions are reached, allowing near-instantaneous response to grid signals. Small-scale systems can achieve even higher ramp-rates.

Finally, when properly designed, electrolysers have the potential to provide flexibility across different time scales, offering short-term ancillary services and long-term storage capabilities. More specifically, due to their immediate response to grid commands, electrolysers can contribute to both ancillary services (voltage and frequency regulation) and reserve power services. Unlike batteries, the use of H2 as a storage technology is best used on a longer-term scale, as it is a technology capable of supporting even seasonal storage. In this way, hydrogen can also reduce the system's dependence on fossil-based flexibility, particularly gas-fired power plants, which are currently often used to cover peak demand and balancing needs. Excess electricity is converted into H2, which is stored either in tanks or in salt caverns. This storage technology is geographically concentrated mainly around the North Sea basin and requires integration into a wider hydrogen transport network. Current deployment of salt cavern storage remains limited, at around 9 TWh under development against an estimated need of 36 TWh to support a 20 Mt European hydrogen system. Salt caverns can be adapted for fast-cycling operations, as demonstrated by Storengy's HyPSTER pilot project. Hydrogen storage can take place throughout the summer months, and the electricity can be used during the winter months either in industry to produce electricity or thermal energy, or for e-fuels and e-gases.

4.3.2 Data Centres

Due to the rapid growth of AI and digital services, the total demand for data centres in Europe is estimated to increase by more than 50% between 2025 and 2030, as illustrated below. This growth significantly transforms their role in the power system, and for this reason, TSOs consider it essential to properly use data centres as flexibility resources for the power system.

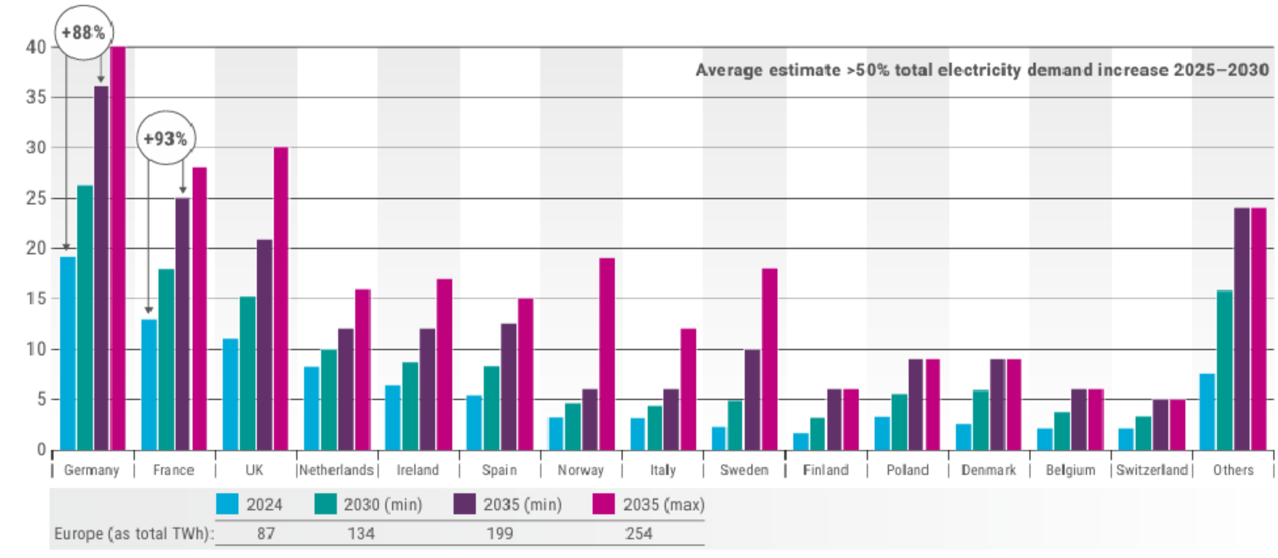


Figure 1: Estimated total data centre electricity demand, by key country (TWh per year)[8]

Figure 7 - Estimated total data centre electricity demand, by key country (TWh per year) [38]

Data centres can be classified into three principal categories based on their ownership and business model: Colocation and service provider data centres, Hyperscale data centres and Enterprise data centres. This distinction is critical for assessing their flexibility, as in colocation the provider controls these facilities but not the workloads, creating a structural barrier to flexibility. In hyperscale data centres there is typically greater central control by large technology companies, such as cloud service providers, and large software-as-a-service

[38] European Network of Transmission System Operators for Electricity (ENTSO-E). (2026). *Data centres and the power system: expected trends, challenges and opportunities*. ENTSO-E Working Group Future of Energy Systems, Brussels, May 2026.

and internet platform companies. Facilities of enterprise data centres are owned and operated by a single organisation for its own use, typically banks and government agencies.
Despite these differences, data centres share certain technical characteristics that can be leveraged to provide flexibility to the power system. Specifically, their contribution can stem primarily from four key areas: the management of IT workloads, the use of UPS systems and batteries, the flexibility of cooling and thermal storage systems, and the use of on-site generation or additional storage.

IT workload management: The computational load itself is a particularly important source of flexibility. It is possible to adjust consumption when maximum computing performance is not required. If adjusting computing power is not feasible, power demands can be shifted either in time or location. Time-shifting the load eases the pressure on the grid during periods of high demand and low production, as it shifts operations to times when the system is better able to handle them, contributing both to reducing demand peaks and to better use of renewable energy sources. For example, tasks such as batch processing, data analysis or certain AI training applications do not need to be performed during periods of network congestion. Geographic shifting can be applied to tasks that need to be executed immediately but are not strictly limited by their execution location: services such as financial transactions or emergency services, if latency and reliability requirements permit, can be relocated to other sites in regions experiencing less grid stress at that time.

The flexibility potential of IT workloads varies considerably depending on their type and latency requirements as shown in the following table. Workloads with low latency sensitivity, such as AI/ML training and batch/data processing, have the highest flexibility potential. On the other hand, transactional and real time loads with very high sensitivity have very low flexibility potential.

Workload Type	Latency Sensitivity	Time-Shift Potential	Geo-Shift Potential	Load Profile	Dominant Business Model	Overall Flexibility Potential
AI / ML Training	Low	High	High	Sustained, bursty step-loads	Hyperscale	High[51]
Batch / Data Processing	Low	High	Medium–High	Schedulable, periodic	Hyperscale, Enterprise	Medium–High
Backup / Disaster Recovery	Low (until failover)	High	Low	Low baseline, surge on failover	Enterprise, Colocation	Medium
AI Inference	Medium–High	Low–Medium	Medium	Variable, diurnal pattern	Hyperscale, Colocation	Medium-Low
Web / SaaS / Content Delivery	Medium–High	Low	Medium–High	Diurnal, traffic-driven	Hyperscale, Colocation	Low
Transactional / Real-Time	Very High	Very Low	Very Low	Steady, mission-critical	Enterprise, Colocation	Very Low

Figure 8 - Evaluation of flexibility potential of IT workload types [39]

UPS systems and batteries: IT loads are particularly sensitive even to small fluctuations in voltage and frequency. For this reason, they are equipped with uninterruptible power supply (UPS) technologies. Although the primary role of these technologies is to ensure the continuous operation of loads, they can also be used by the power system to provide flexibility. More specifically, the immediate response of UPS batteries enables the supply or absorption of power in a very short time, helping to reduce demand peaks or utilize excess generation. However, the duration and storage capacity are limited, and therefore, the contribution of UPS batteries lies primarily in short-term grid support services, such as frequency stabilisation and the provision of primary reserve.

[39] European Network of Transmission System Operators for Electricity (ENTSO-E). (2026). *Data centres and the power system: expected trends, challenges and opportunities*. ENTSO-E Working Group Future of Energy Systems, Brussels, May 2026.

Cooling and thermal storage: Cooling systems, whose primary role is to maintain a stable temperature to protect equipment from overheating, account for a significant share of the load in data centres, which in some cases exceeds 30% of total energy consumption. Cooling offers a significant advantage, as it possesses thermal inertia: the building, the equipment and the cooling circuits can maintain their temperature for a few minutes or even a few hours. This capability allows data centres, if required by the network operator, to temporarily reduce the operation of cooling systems and, consequently, their overall energy consumption, without directly affecting their smooth operation. With the addition of thermal storage, this capability can be further enhanced, thereby supporting the grid during peak or congestion periods.

On-site generation and additional storage: Due to the particular importance of uninterrupted operation in data centres, these facilities often feature, in addition to UPS systems designed for short-term power supply, technologies for long-term on-site power generation, intended to ensure power supply for longer periods of time in cases of disruptions or prolonged outages in the electrical system. The most reliable power generation technology is diesel generators; however, these have limitations due to emissions of carbon dioxide and other pollutants, which restrict their ability to operate for extended periods. A more promising solution, compatible with decarbonisation goals, is to cover part of the generation with RES in combination with storage, either via batteries or H2 storage. These technologies offer a wide range of flexibility options to the TSO: during periods of excess renewable energy production, storage technologies can store this energy and release it when the system needs it. The availability of these technologies is particularly important during periods of high demand or grid congestion, as they can cover part of the data centre's load or, in some cases, its entire consumption.

The suitability of data centre flexibility for specific market products depends on the activation speed, sustained duration and operational availability of each resource. UPS batteries are well suited to fast frequency response and primary reserve (FCR), as their power-electronic interface can respond within milliseconds and sustain output for several minutes. Secondary and tertiary reserve (aFRR, mFRR) are achievable through combinations of IT load shifting, cooling modulation and thermal storage, though sustained delivery over longer periods requires careful coordination with operational constraints. Thermal storage and on-site generation are best suited to energy market products (day-ahead and intraday), as the limited energy-shift capacity of IT and cooling flexibility constrains their contribution to energy-volume services. Data centre load modulation, workload shifting and temporary operation of on-site generation can provide highly targeted, locationally valuable flexibility for congestion management, particularly in grid-constrained metropolitan clusters where data centres are concentrated.

Flexibility Provider	Inertia/Fast Frequency Response	FCR/Primary Reserve	aFRR/Secondary Reserve	mFRR/Minute Reserve	Energy Market (Day-ahead/Intraday)
Activation time	**< 1 s**	**< 30 s**	**30 s – 5 min**	**5 – 12.5 min**	**15 min – hours**
IT UPS Battery	Suitable	Suitable	Possible	Limited	Not suitable
IT Load Shift[63]	–	Not suitable	Possible	Possible	Possible
Cooling UPS Battery	Suitable	Suitable	Possible	Limited	Not suitable
Cooling Load Shift[64]	–	Suitable	Possible	Marginal	Limited
Thermal Storage[63]	–	Limited	Limited	Suitable	Suitable

Figure 9 - Suitability of data centre flexibility providers for inertia, electricity market products, and ancillary services [40]

[40] European Network of Transmission System Operators for Electricity (ENTSO-E). (2026). *Data centres and the power system: expected trends, challenges and opportunities*. ENTSO-E Working Group Future of Energy Systems, Brussels, May 2026.

5. OPERATIONAL INTEGRATION AND SYSTEM COORDINATION

This chapter examines how flexibility moves from a theoretical capability to an operational service. While previous chapters define FaaS and describe the portfolio of flexible resources, this chapter focuses on the coordination mechanisms required to activate those resources reliably in real power system operation. This includes activation logic, control architecture, interoperability, TSO-DSO coordination, cross-vector strategies, cybersecurity and resilience. The chapter therefore treats FaaS as an operational coordination framework rather than only as a market product. To effectively operationalise FaaS, a closed operational loop must be established. This loop consists of sequential steps: forecasting the system needs, qualifying the flexible resource, procuring or scheduling the service, activating the asset, monitoring the physical response, validating the delivery and finally settling the transaction. Reliability is of utmost importance and, in this respect, flexibility must be delivered at the right time, location, duration and reliability level. Distributed flexibility creates coordination challenges because many assets are small, heterogeneous and uncertain.

The following table maps the operational, informational and physical roles of key actors across the SGAM domains and layers, showing how flexibility related coordination extends from transmission to distribution, DER portfolios and customer premises.

Table 6 - SGAM Mapping of TSO–DSO Coordination for Flexibility as a Service

SGAM layer / domain	Generation	Transmission	Distribution	DER	Customer Premises
Market	-	TSO defines system/balancing needs, reserve requirements and activation requirements; market interaction is through market/balancing platforms	DSO may provide grid-constraint information that affects feasibility of flexibility connected to distribution networks	Aggregators/BSPs offer flexibility from DER portfolios into market or contractual mechanisms	Customers may participate indirectly through supplier, aggregator or demand-response contract
Enterprise	-	TSO operational planning, grid security assessment, balancing service procurement process, settlement data exchange, prequalification of BSPs/Agg. assets, coordination agreements with DSOs	DSO planning and operational coordination, grid access management, congestion management rules, flexibility validation procedures	Aggregator/BSP portfolio management, customer contracts, DER availability management, prequalification data	Customer enrolment, consent management, supplier/aggregator contract, reward or tariff information
Operation	-	TSO EMS/SCADA, real-time system monitoring, balancing need detection, activation instruction, congestion/security management, TSO–DSO coordination signals	DSO SCADA/ADMS/DMS, MV/LV constraint monitoring, validation of distribution-connected flexibility, local congestion management	Aggregator/DERMS dispatch of DER portfolio, availability monitoring and forecasting, response tracking	Customer app/HEMS/BEMS receives signal or instruction; customer/device response confirmation
Station	-	Transmission substation RTUs, IEDs, PMUs, protection relays, communication gateways	Primary substation RTUs, feeder automation, MV/LV transformer monitoring, protection and control devices	DER site gateway, local controller, inverter communication gateway, aggregator gateway	Smart meter gateway, home/building energy gateway, EV charger gateway
Field	-	Transmission line sensors, breaker status, voltage/current measurements, protection devices	Feeder sensors, transformer sensors, fault indicators, smart meters, power-quality measurements	PV inverter, battery controller, EV charger, heat pump controller, flexible load controller	Smart meter, controllable appliances, HEMS/BEMS, customer-side sensors and load devices
Process	-	Physical transmission grid, interconnections, power flows, voltage and frequency constraints	Physical distribution grid, feeders, transformers, voltage/loading constraints	Physical DER assets: distributed PV, batteries, EVs, heat pumps, flexible demand	End-use consumption, customer behaviour, building load, industrial/commercial/residential demand

5.1 Activation, control and interoperability of flexible resource

Activation is the point at which an agreed flexibility capability becomes a physical change in injection or withdrawal. The operational design should first distinguish explicit flexibility from implicit flexibility. Explicit flexibility is committed and activated against a defined product, instruction or event, so that delivery can be verified. Implicit flexibility is a consumer or asset response to prices or tariffs without a firm dispatch obligation. Both are valuable, but they are not interchangeable: a probabilistic response to a price signal cannot automatically be counted as a firm reserve or congestion-management action unless the product rules, aggregation method, financial commitments and verification framework make that response dependable.

Explicit activation can be scheduled in advance, triggered by a system event or issued in near real time. It may be manual, semi-automated or fully automated. The faster and more critical the service, the less the chain can depend on human intervention. Frequency containment and fast frequency response require local or automated control. Intraday congestion relief may tolerate a dispatch instruction with several minutes of notice, whilst long-duration demand shifting may be scheduled hours ahead. The control design should therefore be matched to the product rather than imposed uniformly on all resources.

The activation sequence begins when there is a system need, such as a balancing requirement, congestion, a voltage issue, a peak to be reduced or even a resilient event to be managed. Depending on the service, the actor responsible, either TSO or DSO, translate this need into a flexibility request specifying the required volume, location, direction, duration, response time and activation window. This request is then transmitted to the flexibility provider, either directly or through an aggregator, ready to reach the EMS that controls the asset. At this point, the resource responds physically by modifying its generation or consumption profile, and once the expected response occurs, the loop is closed and settlement is enabled. Every step of this chain must be traceable: an activation that cannot be verified cannot be remunerated, and a verification that cannot be audited cannot support a market.

The physical activation of flexibility relies on three broad control modes, summarised in Table 7 below. Under direct control, the system operator or aggregator sends an explicit command to the asset, such as triggering a battery discharge or reducing EV charging rates. Under indirect control, price or incentive signals (such as dynamic tariffs, congestion pricing) influence behaviour while the asset owner retains the final decision. Under autonomous or local control, the asset responds automatically to local grid measurements, as with inverter voltage support or primary frequency response. FaaS will increasingly rely on a combination of these modes, with the aim of matching the service: fast ancillary services such as FCR require automated or direct control to meet activation windows of 30 seconds in continental Europe, whereas slower services can tolerate indirect mechanisms and human decision-making.

Table 7 - Control modes for the physical activation of flexibility: definitions and examples

Control mode	Meaning	Example
Direct control	System operator or aggregator sends a direct command	Battery discharge, EV charging reduction
Indirect control	Price or incentive signal influences behaviour	Dynamic tariff, congestion price signal
Autonomous/local control	Asset responds automatically based on local measurements	Inverter voltage response, frequency response

Interoperability is the condition under which platforms, assets and actors exchange information without bespoke integration for every new participant. FaaS requires a set of shared data objects that follow the service through its entire life cycle: asset registration and pre-qualification data establish what a resource is and what it may offer; common data models and standardised APIs ensure that a request formulated by a TSO, a DSO or a market platform is interpreted identically by every energy management system receiving it; real-time telemetry, metering and baseline data make the physical response observable; time-stamped activation confirmations create the audit trail on which settlement rests.
Interoperability in the operational sense implies that an activation request that is correctly transmitted and executed can still fail to become a service if the surrounding arrangements are not aligned. Contractual interoperability determines whether baselines and activation windows, as well as verification rules and penalty regimes are defined consistently enough for the same resource to serve more than one buyer. Governance interoperability determines which actor holds activation authority when a TSO and a DSO have competing needs on the same asset, and how double activation is prevented. Regulatory interoperability determines whether prequalification requirements, telemetry obligations and aggregation rules are harmonised sufficiently for a service provider to operate across jurisdictions.

The activation chain must also comply with the physical constraints of the underlying resources described in Chapter 4, because the same dispatch logic cannot be imposed uniformly on all of them. Batteries respond within seconds and track setpoints accurately, but their usable flexibility is bounded by state of charge and cycle-life considerations. As an example, buildings respond more slowly, are constrained by comfort bands and exhibit rebound effects: energy not consumed during an activation partly returns afterwards, and this payback must be anticipated in scheduling and settlement. On the other hand, electric vehicles offer fast, controllable power, but their availability depends on user plans and charging needs, so firm commitments can only be made at portfolio level. As regard to CHP units and electric boilers, they couple the electrical response to heat demand, which both constrains the feasible activation window and, where thermal storage is available, they extend it. Energy communities and other aggregated portfolios require an allocation logic that distributes a service request across members while checking local grid limits. Finally, curtailment of PV and wind provide dependable downward flexibility and can support voltage and frequency, but upward flexibility exists only where the plant is already operating below its available power.

5.2 TSO–DSO coordination models for FaaS

When considering distributed flexibility, the same resource may be relevant for TSO balancing and reserves, for DSO congestion management and voltage control, for local peak reduction, and for the market optimisation pursued by aggregators and suppliers. Without coordination, these uses collide: an EV fleet may be instructed by the TSO to reduce consumption for balancing purposes at the very moment the local DSO needs additional consumption on the same feeder to absorb PV in-feed. Coordination is therefore an operational requirement for FaaS.

Three characteristics of distributed flexibility make the problem structural. First, flexibility is location-sensitive: a megawatt has a different value depending on where it is connected, so activations cannot be assessed against system-wide criteria alone. Second, network feasibility must be validated at the level where the resource is connected: an activation that relieves the transmission system may overload a distribution feeder. Third, accountability must be unambiguous: for each service, it must be clear who qualifies the resource, who activates it, who monitors delivery and who settles the transaction. The coordination models that have emerged in European practice resolve these questions in different ways, with different trade-offs. In this respect, four archetypes are described below.

5.2.1. TSO–DSO coordination models and governance options

In European practice, there is not a coordination model that dominates, and the archetypes described below should be read as a set of design options rather than as a ranking. What matters for FaaS more than the adopted archetypes, is how the resulting arrangement preserves a consistent interface for the flexibility provider. In this sense, a resource owner should not need to implement a different technical and contractual integration for every operator that may wish to use the same megawatt.

The proposed archetypes differ along two main dimensions, namely regarding who holds the market interface towards flexibility providers, and the validation of network constraints for the feasibility of an activation to a distribution network. All remaining differences, such as priority rules, bid forwarding, assignment of the market operator role, can be considered as design parameters within those two dimensions.

TSO–DSO coordination options refer to the different ways transmission and distribution system operators can structure their joint procurement of system services (e.g. balancing, congestion management) from flexibility service providers connected at both grid levels. The literature classifies these arrangements as market models along a spectrum from fully integrated to fully siloed coordination[41]:

- the **central market** where the TSO manages the market,
- the **common market** where a single TSO–DSO market procures services from resources connected to both transmission and distribution grids, with no pre-established priority or exclusivity between operators (efficiency is driven by overall economic optimisation);
- the **multi-level market** where separate markets exist for TSO and DSO, but the TSO retains access to distribution-connected resources (DERs) via mechanisms like bid forwarding after DSO-level clearing;
- the **fragmented market**, where TSO and DSO run entirely separate, non-linked markets and the TSO has no access to DERs at all.

These options sit along a spectrum from fully integrated (common) to fully siloed (fragmented) coordination, with trade-offs between economic efficiency, implementation complexity and local grid granularity, the more integrated models tend to improve overall welfare but demand greater data-sharing and joint operational complexity, while more disjointed models are simpler and cheaper to implement but risk sub-optimal system-wide allocation of flexibility.

The four archetypes used in the remainder of this section correspond to this terminology as follows: the centralised model (A) to the central market, the shared model (C) to the common market, and the hierarchical model (D) to the multi-level market. The local DSO-led model (B) is treated here as a distinct archetype because, although it is not a joint procurement arrangement in the sense above, it is the prevailing starting point in most Member States where the DSO is currently the only buyer of local flexibility. The fully fragmented case is not treated as an archetype, since it describes the absence of coordination rather than a coordination mode.

Governance of TSO–DSO coordination is implemented through a set of specific design choices rather than a single "governance" pillar, summarized in Table 8. Collectively, these choices define accountability, decision rights and information-sharing obligations between TSOs and DSOs, and they are not independent of the archetype.

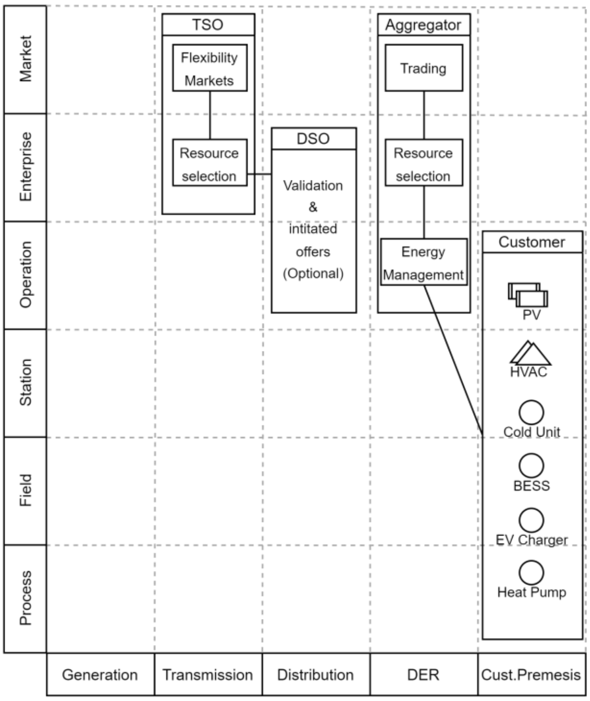
[41] Troncia, M., Chaves Ávila, J. P., Damas Silva, C., Gerard, H., & Willeghems, G. (2023). *Market-Based TSO–DSO Coordination: A Comprehensive Theoretical Market Framework and Lessons from Real-World Implementations*. Energies, 16(19), 6939. [Online]. Available: https://doi.org/10.3390/en16196939

Table 8 - Governance design variable in TSO-DSO coordination

Design variable	Options	What it determines	Typical setting (A-D)
Allocation principle	TSO priority, DSO priority, TSO exclusivity, DSO exclusivity, no priority	Who has first claim on a bid when both operators need it	A: TSO priority B: DSO exclusivity C: no priority D: DSO priority
Commitment to bid selection	Formal/conditional	How binding a system operator's claim on a bid is	A, B: formal C, D: conditional
Bid forwarding	None/direct/via intermediary with grid-constraint check	Whether unused bids can move between sub-markets	A, B: none C: direct D: via constraint check
Market operator role	TSO/DSO/independent operator	Who runs the procurement process	A: TSO B: DSO C: independent or joint D: TSO, after DSO filtering
Optimization methodology	Centralized/decentralized	Whether clearing is single or split across levels	A, C: centralized B, D: decentralized
Shared market phases	Prequalification, procurement, activation, settlement (shared or separate)	Where the operators' processes are common and where they diverge	A: procurement onwards B: none C: all D: prequalification and validation

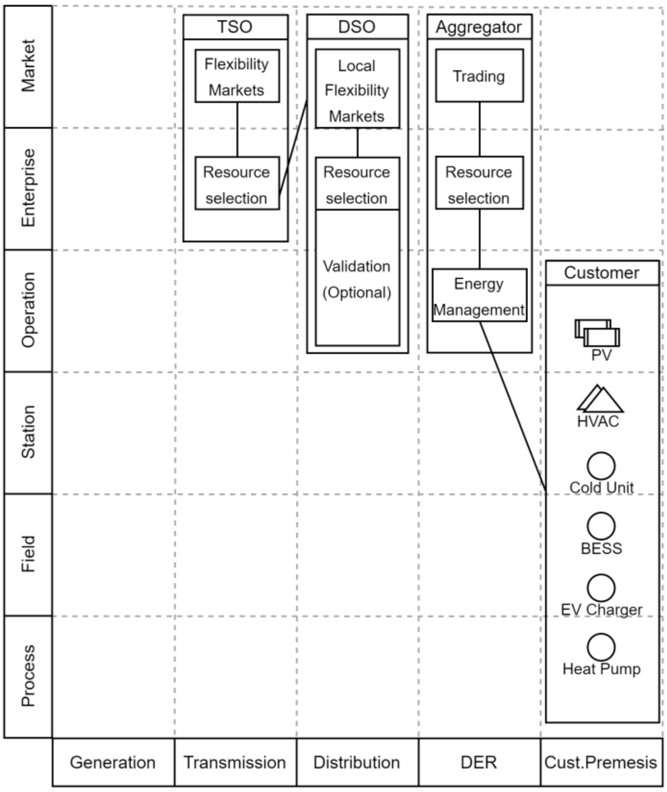
A. Centralised model

The TSO procures and activates flexibility for system-wide purposes, with DSO involvement limited mainly to constraint checking on the affected distribution networks. The model fits balancing and transmission-level services and minimises fragmentation of liquidity, but it presupposes that the TSO has or receives sufficient visibility of distribution constraints; where it does not, activations feasible on paper can violate local limits in practice.



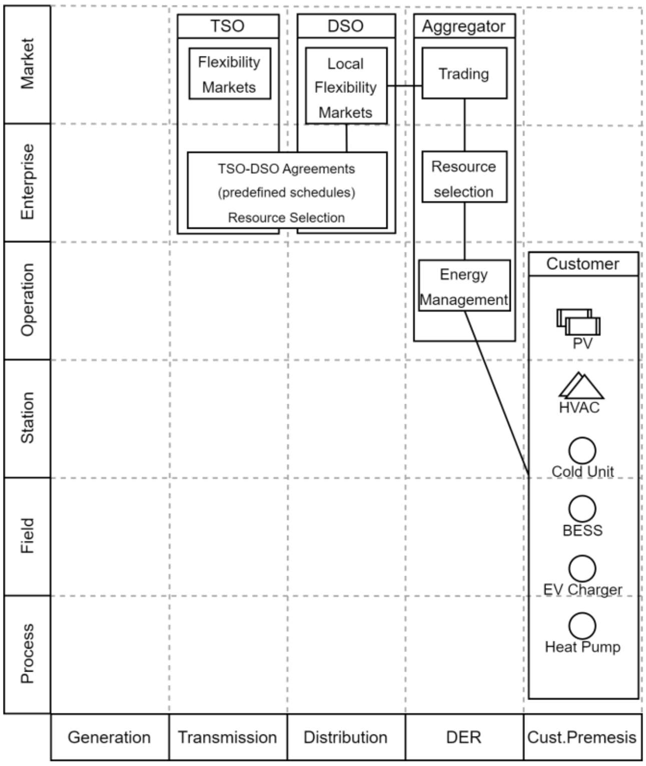
B. Local DSO-led model

The DSO procures flexibility for local congestion, voltage or capacity management within its own network. The model matches the inherently local nature of most distribution constraints and keeps validation close to the asset, but it risks fragmenting the market into small, illiquid pools and generating conflicts with TSO balancing and wholesale positions if the two levels are not reconciled.



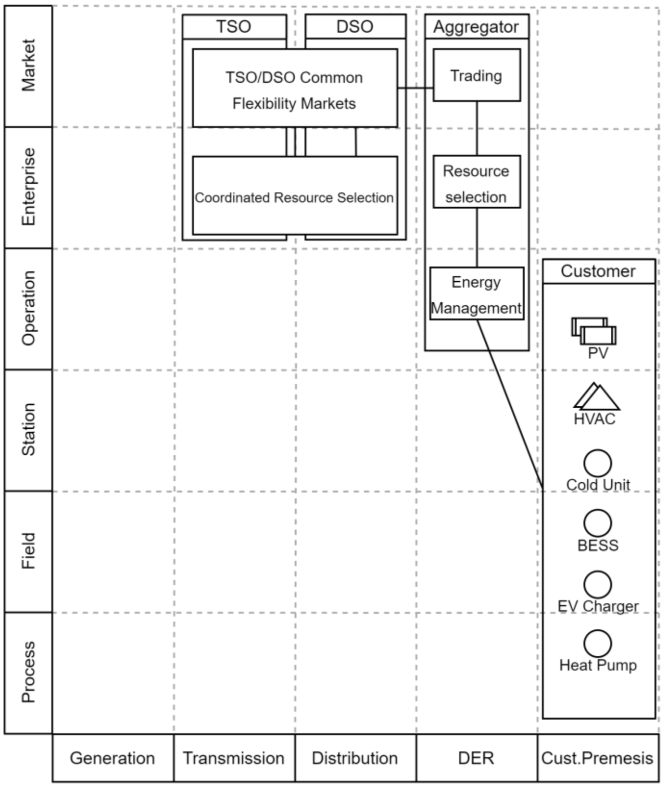
C. Shared/common market-based coordination model

TSO and DSO both express their needs on a common platform; providers submit offers once, and activations are coordinated through shared rules. This maximises transparency and provides a structured mechanism for conflict management, at the cost of higher data, governance and platform complexity. The Dutch GOPACS platform, discussed in Chapter 7, is the most mature European example of this archetype.



D. Multi-level/hierarchical coordination model

The DSO validates distribution feasibility first, and only bids cleared as feasible are passed to the TSO or the market platform for activation. This is the most robust model against distribution-grid violations, but it introduces latency: unless the validation step is automated, it is too slow for fast products.



A comparison of the above-described archetypes under different lenses is presented in Table 9 below.

Table 9 - Comparison of the four archetypes

Archetype	Market interface held by	Distribution feasibility validated	Liquidity	Latency	Principal risk
A: Centralized	TSO	Ex post, as a constraint check	high	low	Activations infeasible downstream
B: Local DSO-led	DSO	Natively local	low	low	Conflict with balancing
C: Shared/common	Joint or independent platform	Through shared rules	high	medium	Data and governance complexity
D: Multi-level/hierarchical	TSO, after DSO filtering	Ex ante, before clearing	medium	high	Too slow for fast products

Models A and C address location-sensitivity by making distribution constraints visible to a system-wide optimization, which is efficient where observability is good and unreliable where it is not. Models B and D address network feasibility by validating it where the resource is connected, at the cost of liquidity in the first case and of speed in the second. On accountability, only C and D make the division of decision rights explicit ex ante; in A and B it is implicit in the fact that a single operator holds both the market interface and the activation decision. In practice, no single model dominates, and the European experiences combine elements of several archetypes. The appropriate choice depends on the maturity of local markets, the observability of the distribution network, and the national allocation of roles. The two questions posed at the beginning of this section, namely who holds the market interface, and where feasibility is validated, should be therefore considered explicitly at the national level.

Resilience imposes a requirement that system-wide adequacy of stabilizing capability does not, by itself, satisfy. Frequency stability, inertial response and voltage support are system-wide services in normal interconnected operation. Their sufficiency, however, becomes a local property the moment a network is separated. In this sense, any portion of the system that can plausibly become islanded following a fault or a controlled disconnection must retain enough inertial response, reactive support and frequency-stabilizing capability to survive the transition. This has as a direct operational consequence that the capabilities of connected resources must be tracked ex ante and attributed to the portions of the network in which they are electrically located, so that the operators can verify, before the event, whether each separable region would remain controllable. It also implies that the dispatch of a unit may be justified on resilience grounds alone, independently of any energy or congestion need, where that unit provides the stabilizing capability a potential island would otherwise lack.

5.3 Hybrid and cross-vector operational strategies

Sector coupling expands the operational flexibility envelope because it allows energy demand to be shifted not only in time, but also between energy carriers. The routes through which this happens are by now well identified:

- heat pumps and electric boilers convert electricity to heat, turning thermal inertia and hot-water storage into electrical flexibility;
- electrolysers convert surplus electricity into hydrogen, coupling the power system to gaseous storage and transport;
- smart charging and vehicle-to-grid link the power system to mobility;
- district heating and cooling networks contribute large, slow thermal stores;
- CHP plants allow electricity and heat production to be co-optimised;
- gas and hydrogen networks provide dispatchable backup and long-duration balancing.

The interaction between electricity, gas and hydrogen systems further expands the operational flexibility envelope by linking fast electrical response with medium- and long-duration gaseous storage and transport. Electrolysers are central in this context, as they can absorb surplus renewable electricity and convert it into hydrogen for later use, storage or transport. However, their flexibility is conditional on hydrogen demand, storage availability and network capability. Likewise, gas and hydrogen infrastructure can support electricity system operation through dispatchable backup and longer-duration balancing, particularly during stressed conditions.

Heat-following operation constrains the electrical modulation of a CHP plant, but thermal storage, auxiliary or electric boilers, bypass arrangements, and extraction-condensing operation can decouple heat and electricity within plant-specific limits. CHP plants can flexibly provide power when heat output is buffered in a thermal heat storage system, thus decoupling the electric production and heat production. This has been commonly used to enable base load operation of the CHP plant without activation of heat only boilers at peak heat demand.

However, it can also be used to operate the CHP flexibly, following demands and price volatility of the electric system. Such use of heat storage opens up the possibility for significant increases in CHP capacity to better provide residual load at better efficiency than possible by power only thermal plants. The same heat storage can be used for demand response of an electric heating solution and also for CHP operation, thereby improving interplay between the two solutions.

When a CHP plant is operated in coordination with an electrified heating solution, the net electrical response can be amplified. Instead of firing additional fuel in a separate boiler or duct to cover heat demand exceeding the available waste heat, a slight overproduction of electricity from the CHP can feed an electric boiler. Fuel consumption is unchanged with respect to boiler or duct firing, but the combination doubles the frequency response: when the CHP increases load to export power to the grid, its heat output also increases, and the e-boiler reduces its load to compensate providing a demand response equal in size to the CHP response. The e-boiler additionally enables flexible use of renewable grid power whenever this is advantageous, and can naturally be replaced by a large-scale heat pump. The response is not universally doubled but it illustrates how coordination across vectors creates flexibility that neither asset could offer alone.

Peer-to-peer information exchange can be a way of improvement of grid management. Knowledge of the operating mode and dispatch of one plant can be used to put another plant in a state that makes it ready to complement or compensate for events in the first plant. As an example; when power varies from a renewable plant, e.g. solar field, the measured power variation can be counteracted directly by dispatch from another plant, and detailed forecasting for dispatch, e.g. from solar fields, in short time frames can be used to boost such coordination too. Another example is when an energy storage device approaches shut down due to complete discharge of energy, a call for startup of a thermal plant can be made such that the load dispatch is seamlessly handed over. Or when one generator suffers a trip condition, a storage device can instantly ramp up dispatch to compensate for the loss of power before any frequency disturbances occur. Many foreseeable events can in such way have pre-programmed mitigations to improve the stability and resilience of grid operation.

The concept of virtual hybrid plants can be extended to include electrolysers, hydrogen storage, compressors and gas- or hydrogen-fuelled generation. In such cases, the operational state of one infrastructure can directly inform the dispatch of another, allowing more coordinated system response across vectors, as reported in Table 10. This is important because electricity, gas and hydrogen systems are subject to different physical constraints, and coordinated operation can therefore improve both flexibility provision and overall system resilience.

Table 10 - Hybrid and cross-vector resources and their operational value for FaaS

Hybrid/cross-vector resource	Operational FaaS value
CHP + thermal storage	Electricity dispatch while maintaining heat supply
Heat pumps/e-boilers + DHC	Absorb RES surplus, shift heat production
BESS + PV/wind	Smooth RES output, provide fast response
EV smart charging/V2G	Shift mobility demand, provide local congestion support
Electrolysers	Absorb excess renewable electricity, support long-duration storage
Water/wastewater pumping	Shift pumping load without affecting service continuity
Gas/hydrogen compressors	Flexible electric demand in multi-energy systems

Gas-, hydrogen- and biomethane-related assets complement batteries and thermal storage because they are better suited to longer-duration flexibility. While batteries typically provide short-duration balancing, gaseous infrastructure can support intra-day, multi-day and potentially seasonal balancing through storage, linepack and dispatchable supply. Biomethane may further strengthen this framework by preserving part of the operational role of gas infrastructure while contributing to decarbonisation.

Multi-vector operation raises coordination requirements of its own. Forecasting must cover several carriers simultaneously, since an error on the thermal side propagates to the electrical commitment. Thermal and electrical constraints must be respected jointly, and sector-specific service continuity (heat delivery, water treatment, mobility needs) always takes precedence over grid services. Coordination is required between electricity system operators and the operators of heat, gas, water and mobility infrastructure, whose planning cycles and operational cultures differ. Finally, a clear prioritisation is needed between energy efficiency, system support and customer service quality, because the three objectives do not always align. In practice, the value of electricity–gas–hydrogen coordination depends on explicit recognition of infrastructure constraints: electrolysers, compressors, storage facilities and dispatchable gaseous generation cannot be treated as unconstrained flexibility resources, as their operation depends on pressure limits, storage conditions, fuel delivery capability and downstream demand. Their role is therefore best assessed within a whole-energy-system framework that captures network-constrained operation and the differing timescales of short- and long-duration flexibility.

5.4 Cybersecurity and operational resilience as enablers of flexibility services

Cybersecurity and operational resilience are enabling conditions for FaaS. A flexibility service is a commitment to deliver a physical response at a specified time and place after verification; if the digital chain that carries the instruction and the evidence of delivery cannot be trusted, there is no service to contract, whatever the underlying asset is capable of doing. More specifically, a service that cannot be trusted cannot be contracted: security and resilience determine which flexibility can be brought to market and therefore belong to product design rather than to implementation.
Every activation involves remote control of physical assets, the exchange of operational data, metering and settlement data, aggregator platforms, cloud or edge control systems, and communication among TSOs, DSOs and market platforms. FaaS needs reliable data exchange, interoperability and digital trust in order to be contracted, activated and validated. Each of these dependencies is also a potential risk element.

A compromise anywhere along the chain has direct physical and economic consequences. False activation signals cause assets to respond when they should not, whilst blocked signals make contracted flexibility unavailable precisely during system stress, when it is most needed. Manipulated telemetry corrupts validation and settlement. In this sense, a data breach exposes consumer and asset behaviour and, at a higher level, a compromised aggregator platform affects thousands of distributed assets simultaneously. If the risk is on the communication, this outage removes observability and control, whilst a coordinated attack on controllable load or generation could turn flexibility itself into a source of instability rather than support. Table 11 summarises these risks and their operational consequences.

Table 11 - Cyber-physical and data-related risks to flexibility provision and their operational consequences

Risk	Operational consequence
False activation signal	Assets respond when they should not
Blocked activation signal	Contracted flexibility unavailable during system stress
Manipulated telemetry	Incorrect validation and settlement
Data breach	Exposure of consumer/asset behaviour
Aggregator platform compromise	Many distributed assets affected simultaneously
Communication outage	Loss of observability and control
Coordinated cyberattack	Flexibility becomes a source of instability instead of support

Treating security and resilience as enablers has a concrete consequence for how flexibility products are specified. Requirements that are often left to implementation are properties of the product, since they determine whether delivery can be verified and therefore whether it can be remunerated. They belong in prequalification criteria and in contractual terms alongside response time, duration and volume. Where they are not specified, the residual risk is not eliminated but transferred implicitly to the system operator, who discovers it only when flexibility fails to materialise under stress. The security requirements that make a flexibility service dependable are not, however, equally enforceable across the resource base. Requirements of this kind were developed for a small number of large, professionally operated plants, where certification, continuous monitoring and periodic audit are proportionate to the value of the connection. They do not transpose unchanged to a resource base composed of hundreds of thousands of small providers, where the cost of compliance can exceed the revenue the asset earns and where the practical effect of demanding too much is exclusion rather than security. The difficulty is compounded by the falling cost of attack: automated and increasingly AI-assisted intrusion makes large populations of similar, weakly defended endpoints an attractive target precisely because each individual one is of negligible value. The response is not to lower the requirement but to relocate it. Obligations should remain proportionate to the size of the individual connection while being calibrated on the aggregate criticality of the portfolio, with the aggregator or platform operator, rather than the household device, carrying what a small provider cannot reasonably discharge: authentication, patching and firmware lifecycle management, anomaly detection across the fleet, and the ability to isolate a compromised segment without losing the remainder. This is consistent with the role-based logic of Delegated Regulation (EU) 2024/1366.

Secure operation rests on a communication layer that establishes trusted interactions among all participating entities while ensuring the confidentiality and integrity of information exchanged across the system. To achieve this, the communication infrastructure supports authenticated and traceable control actions and resilient operation if communication failures occur. Established standards cover most of this ground: IEC 61850 for substation and grid automation, IEC 60870-5-104 and DNP3 in control-system environments, OpenADR for demand-response signalling, MQTT- and HTTPS-based APIs for IoT and platform communication, and CIM-based information models (IEC 61970/61968) for system and market data exchange.

Beyond technical standards, the evolving European regulatory framework provides an additional layer of assurance by extending cybersecurity requirements across both cloud-based services and connected devices. Digital platforms supporting flexibility services may fall within the scope of NIS2, while the Cyber Resilience Act (CRA) establishes harmonised cybersecurity requirements for connected products throughout their lifecycle. Sector-specific rules are set by the network code on cybersecurity established by Commission Delegated

Regulation (EU) 2024/1366, which introduces a common framework of minimum requirements, risk-assessment methodologies and information-exchange procedures for entities relevant to cross-border electricity flows. For FaaS, its significance consists in the fact that cybersecurity obligations rely on the role of an entity and not to the technology that is deploys.

Together, these regulations make it possible for most components involved in flexibility services—from cloud platforms and aggregators' digital infrastructure to smart chargers, gateways and home energy management systems—to be integrated into coherent cybersecurity frameworks spanning both cloud and edge environments. The challenge for FaaS is less the absence of standards than their consistent adoption across a fragmented landscape of vendors, platforms and small actors, which ties this section directly to the interoperability requirements of Section 5.1 and the data-governance requirements of Chapter 6.

Operational resilience extends the same requirement beyond deliberate attack to all failure modes, including for example communication outages, platform failures, extreme weather, prolonged low-renewable conditions and system restoration. A second principle follows from the same reasoning and is well established in other high-reliability domains: diversity as a defence against common-cause failure. Where safety-critical systems must not fail simultaneously, they are deliberately assembled from instruments of different types, vendors and design lineages, so that a single defect, a single vulnerability or a single erroneous setting cannot propagate through the entire population. Aggregated flexibility is exposed to precisely this failure mode. A portfolio of many independently owned assets may nonetheless be homogeneous in the respects that matter the same inverter firmware, the same protection settings, the same cloud service, the same communication path. Heterogeneity of technology, vendor and control path should therefore be treated as a resilience property of a flexibility portfolio, to be assessed at prequalification alongside volume and response time.

The common design principle implies that a flexibility service should degrade predictably rather than disappear. This means that local autonomous control, manual override and an explicit prioritisation of critical services are part of what makes a service dependable, not contingency measures added afterwards; a resource whose contribution is unavailable precisely during the conditions that create the need for it is not delivering flexibility in any useful sense. System resources preferably should be able to go into a safe mode, instead of tripping out.In such situations, the interaction between electricity, gas and hydrogen systems can provide important fallback capability, provided that local autonomous control, manual override and clear prioritisation of critical services are in place. Gaseous infrastructure may support continuity through dispatchable supply, linepack and stored energy, while electrical assets can provide faster response and restoration support. The resilience value of these cross-vector interactions therefore lies not only in normal-operation flexibility, but also in their ability to preserve service continuity and support system recovery under rare but high-impact events.

5.5 Holistic architecture for a systemic approach

INTERACT – Integration of Innovative Technologies of Positive Energy Districts into a Holistic Architecture – is an international research and innovation project with a cross-sectional collaboration between academia, municipalities and businesses.

The electric power system is a physical entity that includes various appliances owned and operated by different stakeholders. Each control action always impacts the behaviour of the whole system. Control schemes that do not rely on a holistic approach consider the perspective of individual stakeholders (TSOs, DSOs and customers) and optimise individual functionalities, thus leading to suboptimal solutions. The holistic architecture enables the efficient and secure operation of the system as a whole.

A holistic power system architecture is an architecture in which all relevant components of the power system are merged into one single structure. These components could comprise the following:

- electricity producer (regardless of technology or size, e.g. big power plants, distributed generations, etc.),
- electricity storage (regardless of technology or size, e.g. pumped power plants, batteries, etc.),
- electricity grid (regardless of voltage level, e.g. high-, medium- and low voltage grid),
- customer plants, and
- electricity market.

The holistic architecture unifies all interactions within the power system itself, between the network-, generation- and storage-operators, consumers and prosumers, and the market, thus creating the possibility to harmonise them without compromising data privacy and cybersecurity. It facilitates all processes necessary for a reliable, economical and environmentally friendly operation of smart power systems. It allows a clear description of the relationships between different actors and creates conditions for a problem-free transition phase.

More information on this topic can be found in White Paper on Holistic Architectures for Future Power Systems released by the ETIP SNET Working Group on Reliable, Economic and Efficient Smart Grid System in 2020.

The holistic architecture, *LINK*, which is based on the fractal geometry of smart grids, facilitates the modelling of the entire power system from high to low voltage levels, including customer plants, thereby ensuring flexibility across the entire grid. It enables the description of all power system operation processes such as load-generation balance, voltage assessment, dynamic security, price- and emergency-driven demand response, etc.

The INTERACT project technical use cases[42] are described in four categories: normal and abnormal operation, flexibilities and long-term planning (see Figure 10). The following subchapter describes business cases based only on flexibility use cases. For each of them a process chart in a standardised layout and the description of the process flow are given. They show the actors involved, the goal of the use case and a potential expected reaction on the process.

[42] D 4.2: Use Cases for the integration of the existing innovative technologies with the *LINK*-solution, INTRACT project, 15 July 2022.

Figure 10 - Summary of technical use cases of INTERACT project

5.5.1 Providing flexibility to the market

Providing flexibility to the energy market is one of the key potential future activities analysed. INTERACT energy communities (EnC) are enabling this by using a standardised structure and common interfaces – as proposed with the holistic *LINK* architecture (Ilo & Schultis 2022, p. 61). With the correct ICT structure, the trigger points from the grid starting different demand-response processes are processed by the EnC and forwarded to the EnC members. On the market side, with the current structure of the energy market, the service can (theoretically) be offered either directly on the ancillary services market, to energy suppliers or through flexibility aggregators, depending on the flexibility potential of the EnC. How the process would look with the proposed INTERACT energy market structure is described below in Business Case 3.7 – Fully integrated Operation.

- **Short description**

Integrated operations are achieved when the communication chain with the grid is enabled, supporting the grid processes and providing additional stability to the power system. Providing flexibility to the market is the first and most important process at this stage. This is achieved by defining and accessing flexibility potential within the EnC and using this potential based on the power grid needs. Figure 11 shows the actors involved and the principle of this operation from a technical and market perspective.

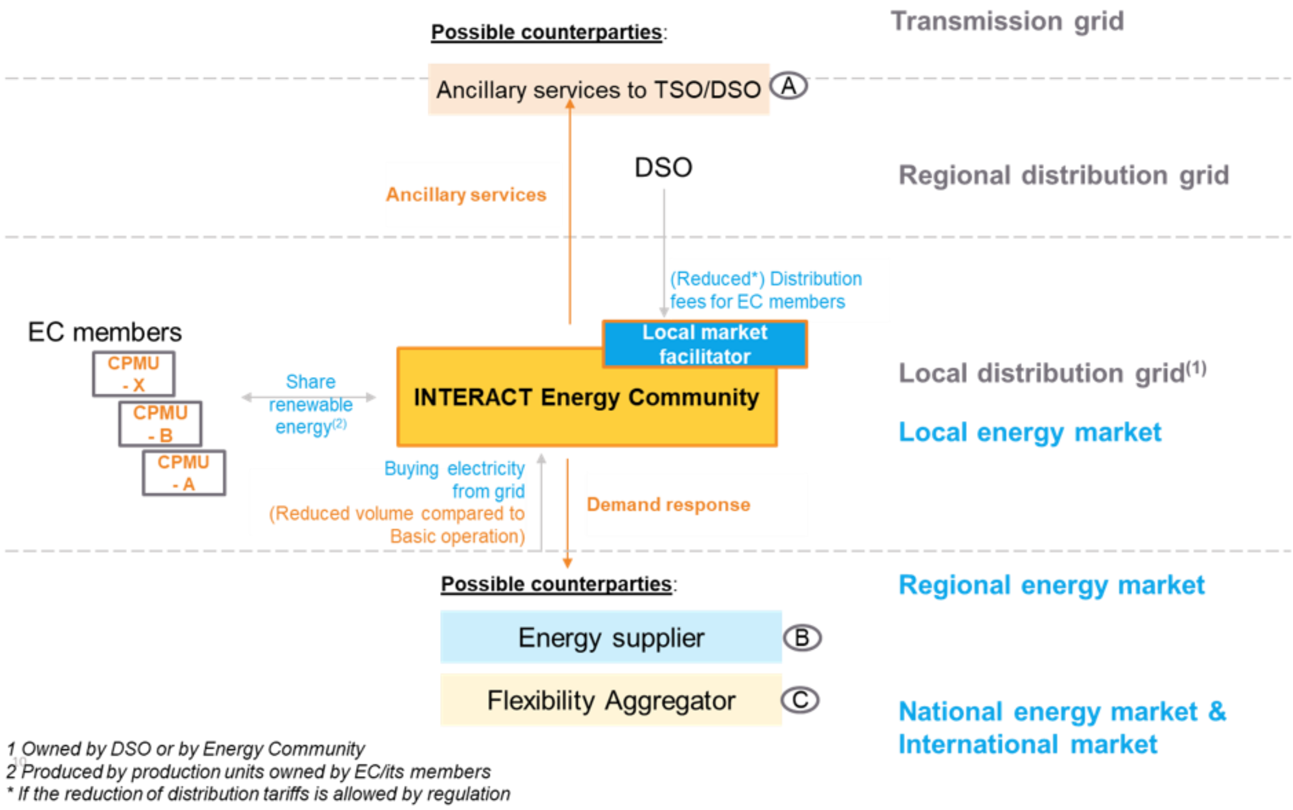


Figure 11 - Providing flexibility to the market.

- **Possible configurations and freedom of design**

There are three types of possible counterparties for providing flexibility, which differ in the type of service provided (see Figure 11) via bilateral agreements or flexibility markets:

A. DSO or TSO and provision of ancillary services,
B. energy supplier and provision of Demand-Response service to reduce his trade imbalances in the short-term market,
C. flexibility aggregator and provision of demand-response service to reduce his trade imbalances in the short-term market or to contribute to an aggregated diagram for ancillary services.

These services can be provided through INTERACT EnC by shifting energy consumption to a different time – by various appliances (so called controllable loads: smart chargers, energy storage appliances or other appliances with controllable load). A local market facilitator embedded in the INTERACT EnC notifies the respective customer plant management units (CPMU) to execute the demand increase. The specific case for deploying e-mobility in the INTERACT EC to promote additional and valuable flexibility resources is described at Ilo, A. et al. (2022).

These services are not mutually exclusive – in fact they all fulfill the same goal: to modify the load to balance surplus in the grid. This can be driven either by congestion alleviation in the case of ancillary services (see description of D 4.2 Flexibility Use case: Congestion alleviation – Emergency-driven demand response) or by price in the case of reduction of trade imbalances in the short-term market (Use case: Price-driven Demand Response in D 4.2).

It is more likely that only one service option will be chosen for a given community. The choice will be influenced by market opportunities (price for the service provided and qualification conditions for the delivery of the flexibility service). Stricter conditions will be required for the direct provision of ancillary services in terms of minimum power provided and granularity of measured data.

The least complicated option might be to provide these services to the energy supplier that is selling electricity to INTERACT EnC.

- **Cost- and Revenue Structure**

Table 12 below shows the changes in the cost- and revenue structure. As can be seen in the table, no additional OPEX occurs in comparison to the advanced operation, as the CPMUs and the necessary advanced EnC communication platform are already in place.

The service needs to be set-up, both internally by defining and accessing the available flexibilities within the EnC, and afterwards externally by linking the EnC to one or more of the counterparties named above.

Table 12 – Cost structure and revenue streams: Providing flexibility to the market

Cost structure	**Investment**	Community assets (production facilities, storage facilities, etc.) ICT structure, including advanced EC Communication platform and CPMU unit for each member
	Operation	Increased purchase of electricity from EnC members Reduced purchase of electricity at the market (energy supplier) Maintenance of ICT structure, incl. CPMU Administration (billing, memberships, bookkeeping, etc.)
Revenue streams	**Operation**	Increased sales of electricity to EnC members Reduced sales of surplus electricity to the market (energy supplier) Increased support through reduced distribution tariffs Support through direct funding of EC operations (if available) Membership fees / additional service fees (if available)

5.5.2 Provision of back-up power

The second described business case for the integrated EnC is derived from the abnormal operation use case. In this case, the EnC provides back-up power during black-outs.

- **Short Description**

INTERACT EnC via coordination and activation of free capacities within the community can reduce the recovery time after partial or complete power outage. For this business case, special storage facilities might be kept by the EnC. Figure 12 below shows the storage of renewable energy for emergency cases against the share of renewable energy.

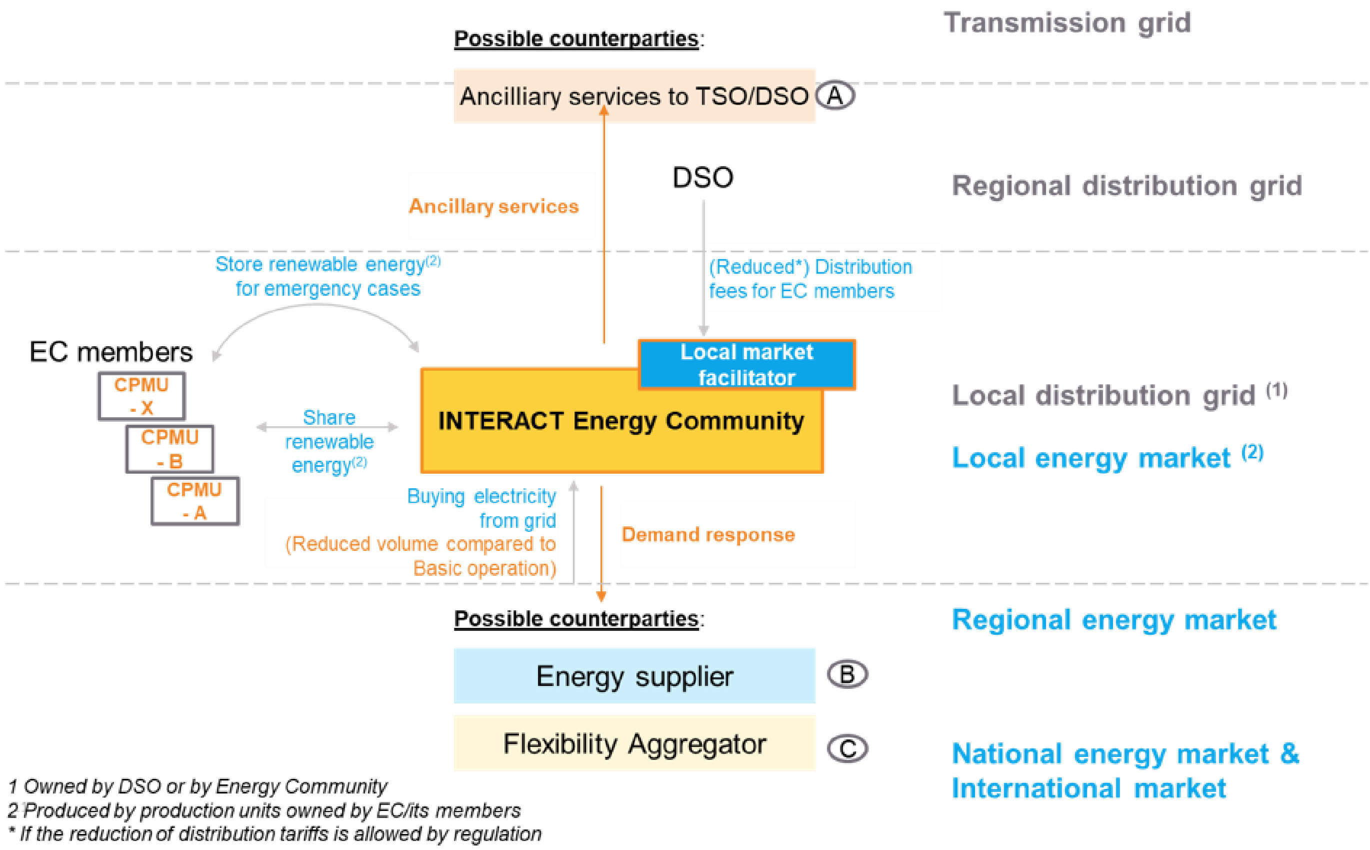


Figure 12 - Providing back-up power.

- **Possible configurations and freedom of design**

This business case is a supplementary case to “Provision of the flexibility to the market”, as provision of back-up power (black start) is one of the ancillary services.

Depending on the requests of EnC members, the provision of back-up power in emergency cases can be offered first within the community, and only afterwards to the market. To enable this business case, the EnC probably needs to invest in additional energy assets (on the side of energy storage) to guarantee the availability of energy in emergencies.

Pricing of the service can be either on demand or like insurance services with a flat fee, and no extra charges when the service is actually needed. As the EnC is a non-profit organisation, the overall expected revenue of the service should correlate with the overall total investment costs of the storage over its expected lifetime. A potential price margin of the service to market prices might be shared between the EnC members or used for further development of the EnC.

- **Cost- and revenue structure**

Regarding the cost structure, CAPEX of additional storage might be necessary. On the other hand, additional revenue through the newly provided service can be added, as shown in Table 13.

Table 13 - Cost structure and revenue streams: Provision of back-up power

Cost structure	**Investment**	Community assets (production facilities, storage facilities, etc.) ICT structure, including advanced EC Communication platform and CPMU unit for each member Additional storage facilities for emergency cases (if needed)
	Operation	Increased purchase of electricity from EnC embers Reduced purchase of electricity on the market (energy supplier) Maintenance of ICT structure, incl. CPMU Administration (Billing, Memberships, Bookkeeping, etc.)
Revenue streams	**Operation**	Increased Sales of electricity to EC members Reduced Sales of surplus electricity to the market (Energy Supplier) Increased Support through reduced distribution tariffs Support through direct funding of EC operations (if available) Membership fees / additional Service Fees (if available) Revenue from Flexibilities sold to the energy market Revenue from Back-up power provided and/or ensured

5.5.3 Fully integrated flexibility services: INTERACT market structure

The fully integrated flexibility services are reached, when the EnC is both connected and embedded into the power grid, as well as into the electricity market structure. INTERACT proposes a new energy market structure, which enables this connection in a standardised and seamless manner based on the *LINK* architecture.

- **Short description**

The proposed new market structure is derived from the structure of the power grid and follows the current technical grid levels: high-voltage grid, medium-voltage grid and low-voltage grid. Subsequently, national, regional and local markets are derived, which are connected to each other, see Figure 13.

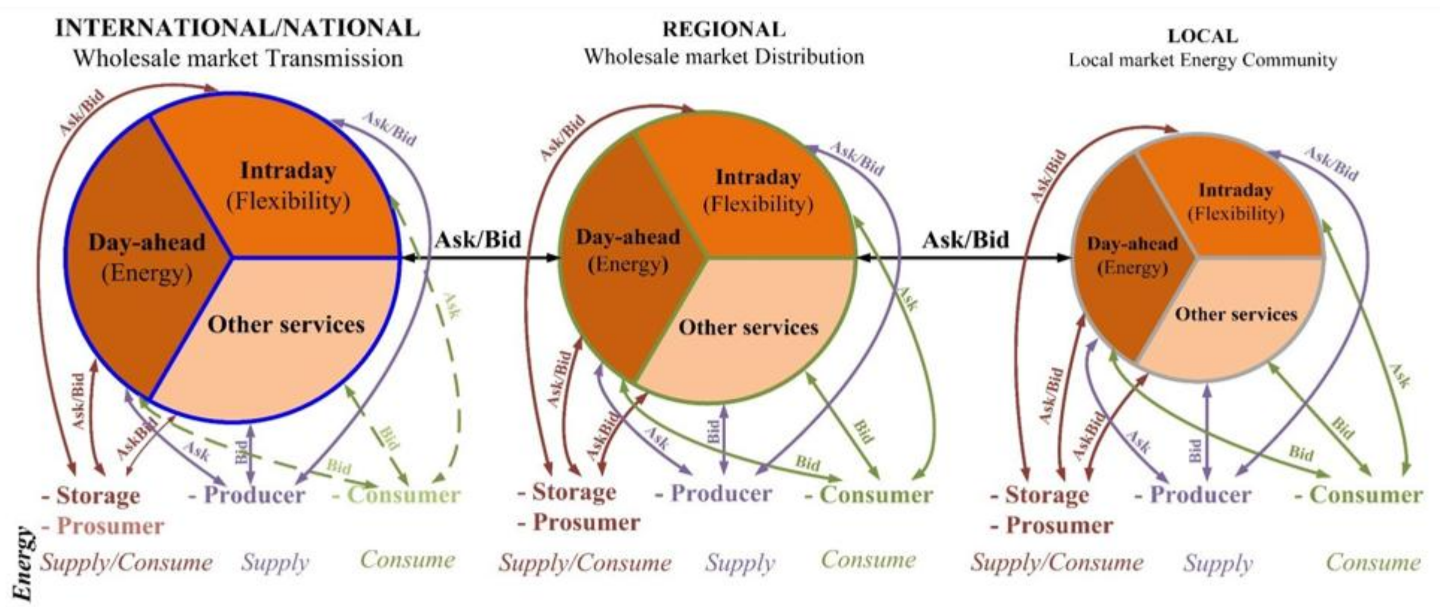


Figure 13 - Connected national, regional and local energy markets in accordance with the LINK architecture.

Thanks to this proposed market structure, prices are generated on each level in an iterative way, balancing demand and supply on each grid level in connection with the demand and supply of the level above. No aggregator is needed, as each market is automatically included in the market on the next level as one consolidated participant. This has positive implications on data privacy and information security aspects.

The fully integrated energy community makes prices on the local level based on the internally agreed pricing strategy. Excess production and/or required consumption are gained based on the prices set by the regional market. The same is valid for potential intraday flexibility and other services. The automatic connection to the higher-level market should avoid inefficiencies. Further research is needed to simulate and validate this proposed energy market model.

Figure 14 below shows the impact on the business operation of the energy community by fully integrated flexibility services. Energy flows on the grid level are mirrored by money flows on the market level.

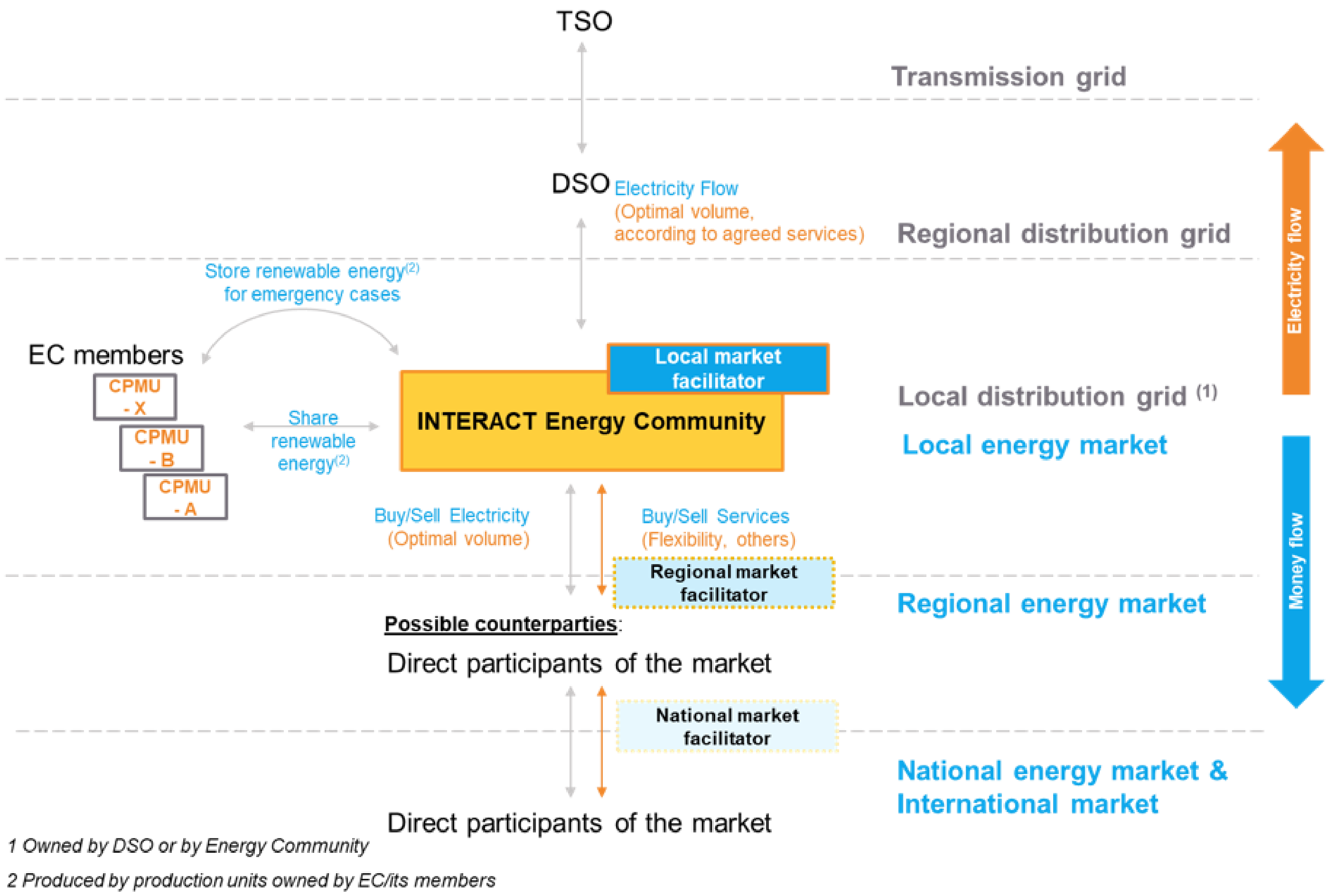


Figure 14 - Fully integrated flexibility services.

- **Cost and revenue structure**

Regarding the cost- and revenue structure (see Table 14 below), no additional elements are necessary. The revenue streams should be optimised in accordance with the market needs and local possibilities. Automated market participation should minimise related indirect costs.

Table 14 - Cost structure and revenue streams: Fully integrated flexibility services

Cost structure	**Investment**	Community assets (production facilities, storage facilities, etc.) ICT structure, including advanced EnC communication platform and CPMU unit for each member Additional storage facilities for emergency cases (if needed)
	Operation	Optimal purchase of electricity from EC members Optimal purchase of electricity at the market (energy supplier) Maintenance of ICT structure, incl. CPMU Administration (billing, memberships, bookkeeping, etc.)
Revenue streams	**Operation**	Optimal sales of electricity to EnC members Optimal sales of surplus electricity to the market (energy supplier) Increased support through reduced distribution tariffs Support through direct funding of EC operations (if available) Membership fees / additional service fees (if available) Optimal revenue from flexibilities sold to the energy market Optimal revenue from back-up power provided and/or ensured

6. DATA, METHODS AND VALIDATION

To become operationally reliable and economically viable, flexibility must be quantified, modelled, activated, and validated through consistent methodological approaches. This requires a methodological backbone that links physical capabilities, portfolio operation, and system needs through consistent data, modelling, and validation approaches. This chapter focuses on the data, modelling methods and validation principles that underpin credible flexibility services.

6.1 Modelling approaches for flexibility assessment

Flexibility assessment requires modelling approaches that explicitly capture time, power, energy, uncertainty and system constraints across temporal scales ranging from sub-second response to seasonal planning. Unlike traditional capacity-based modelling, FaaS-oriented models must represent flexibility as a conditional service rather than as a static asset property, accounting for the heterogeneity, uncertainty and context dependency that characterise flexible demand and distributed resources. A key principle of FaaS-oriented modelling is the distinction between technical flexibility potential and deliverable flexibility services. While the former describes what assets could theoretically provide under ideal conditions, the latter reflects what can be reliably activated, validated and remunerated within a real operational context.

Three complementary modelling layers, discussed in Table 15, can be distinguished:
Asset-level models, which describe the physical flexibility envelope of individual resources (power limits, ramp rates, energy constraints, comfort bounds, state variables). These models define what is technically feasible.
Aggregation and coordination models, which describe how heterogeneous assets are combined into portfolios by aggregators or system operators. At this level, flexibility becomes probabilistic and diversity effects emerge.
System-level models, which assess the interaction between flexibility services and network constraints, balancing needs and market signals. These models evaluate the actual system value of flexibility.

Table 15 - Three complementary modelling layers for FaaS

Layer	What it represents	Key questions	Typical outputs	Main actors
Asset-level	Physical flexibility envelope of an individual resource	What is technically feasible? What physical, operational and comfort limits apply?	Feasible operating region; power, energy and ramp constraints; rebound dynamics	Asset owners, local controllers
Aggregation & coordination	Combined behaviour of heterogeneous portfolios delivering a service	What is reliably deliverable, with what confidence? How are rebound and recovery managed?	Probabilistic service capability; baselines; activation and allocation strategies; reliability margins	Aggregators, balancing parties responsible, balancing service providers
System-level	Interaction of flexibility services with network constraints, balancing needs, and market signals	Does flexibility deliver actual system value? Where, when and at what cost relative to alternatives?	Locational value signals; network-feasible capability; procurement and coordination signals	TSOs, DSOs, market operators

<u>**Asset-level models: feasible flexibility envelopes**</u>

Asset-level modelling answers the question "*What is technically feasible?*". It characterises the feasible operating region within which an individual resource can modify consumption or production without violating physical, operational or comfort constraints[43],[44],[45],[46]. This modelling layer typically includes:

- Power bounds and modulation range (minimum/maximum power, controllability range)
- Dynamic constraints (ramp rates, response delays, minimum on/off times)
- Energy/state constraints (state of charge for batteries, thermal inertia for buildings, process states in industry)
- Service-quality constraints (comfort bands, process quality, operational continuity)
- Recovery and rebound dynamics (post-activation compensation or "payback" effects)

Asset-level models are essential because they define what is technically feasible and what cannot be provided under any circumstance. However, feasibility does not automatically translate into a service. In FaaS, asset-level modelling acts as a safety and feasibility layer: it constrains control actions, informs pre-qualification rules and metering requirements, and prevents activation strategies that would be unrealistic or non-compliant.

Aggregation and coordination models: portfolios, uncertainty and service delivery

Aggregation and coordination models answer the question "*What is reliably deliverable?".* They describe how a set of heterogeneous assets – each with its own constraints, availability patterns and behavioural drivers – can deliver a coherent flexibility service, shifting the modelling objective from feasibility to deliverability[47], [48],[49],[50],[51]. Key functions include:

- *Portfolio representation and diversity effects.* Aggregation exploits heterogeneity (different users, technologies, schedules) to smooth individual variability. Flexibility becomes a property of the portfolio rather than of any single asset.
- *Uncertainty quantification and risk management.* Distributed flexibility is often uncertain (occupancy, user behaviour, stochastic availability). Portfolio models must therefore produce probabilistic service descriptions (expected response, confidence margins, under-delivery risk), enabling realistic commitments.
- *Control and allocation strategies.* Coordination models translate a service request into asset-level actions while enforcing constraints and fairness/participation rules when needed.

[43] Sanandaji, B. M., Vincent, T. L., & Poolla, K. (2016). *Ramping Rate Flexibility of Residential HVAC Loads*. IEEE Transactions on Sustainable Energy, 7(2), 865–874. [Online]. Available: https://doi.org/10.1109/TSTE.2015.2497236

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[50] Cui, B., Zamzam, A., & Bernstein, A. (2021). *Network-Cognizant Time-Coupled Aggregate Flexibility of Distribution Systems Under Uncertainties*. 2021 American Control Conference (ACC), 4178–4183. [Online]. Available: https://doi.org/10.23919/ACC50511.2021.9482808

[51] Barot, S., & Taylor, J. A. (2017). *A concise, approximate representation of a collection of loads described by polytopes*. International Journal of Electrical Power & Energy Systems, 84, 55–63. [Online]. Available: https://doi.org/10.1016/j.ijepes.2016.05.001

Beyond optimisation, the aggregator is the contractual and operational counterpart to system operators and markets, and assumes accountability for service performance[52],[53]. Modelling outputs must therefore support service sizing and qualification, the definition of reliability margins and availability commitments, and ex-post performance evaluation.

Accountability, in turn, requires measurement – which makes baseline modelling a structural component of the aggregation layer rather than an accounting detail. Baseline methods address the fundamental counterfactual question: *"What consumption or production would have occurred in the absence of activation?"*. Baseline modelling is not a mere accounting detail but an integral component of service definition, validation, and remuneration. Baseline methodologies should be consistent with the flexibility service product definition (time window, temporal granularity, activation logic); be robust to contextual drivers such as weather, occupancy, operational schedules and seasonality; minimise systematic bias; reduce opportunities for strategic manipulation; and enable transparent and repeatable ex-post validation[54],[55],[56]. A key implication is that baseline modelling and portfolio modelling cannot be treated independently. Inaccurate baselines directly distort measured service delivery, undermine trust among stakeholders and weaken the economic and regulatory credibility of FaaS.

System-level models: networks, balancing needs, and market signals

System-level models answer the question *"Does flexibility deliver actual system value"* under real network, operational and market conditions. At this layer, flexibility is represented primarily as a service input, characterised by where, when, how much, for how long and how reliably it can be delivered, rather than by detailed asset internals. This abstraction allows system operators and planners to compare flexibility-based solutions with alternatives such as redispatch, reserve procurement or grid reinforcement[57].

For DSOs in particular, the value of flexibility is inherently local: a megawatt is not the same everywhere and its usefulness depends on where and when it is delivered[58]. System-level modelling is therefore also a tool to expose and manage conflicts – between congestion management and energy-cost optimisation, or between DSO needs and TSO balancing requirements[59],[60]. In market-based implementations of FaaS, it further helps assess how flexibility activation responds to price signals and whether procurement mechanisms truly reflect

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system value rather than theoretical potential.

A specific and increasingly important application of system-level modelling is the estimation of the aggregate flexibility that a distribution system can offer at its connection with the transmission system [61],[62]. Individually, distributed resources are small; in aggregate, and subject to network constraints, they form a feasible region in the active-reactive power plane – a "PQ flexibility area" whose shape depends on available resources, network state and operational limits. Two families of methods are used to estimate this region: Monte Carlo approaches examine samples many feasible operating points and test each against grid constraints, building the region empirically; optimisation-based approaches trace its boundary directly by maximising flexibility along chosen directions in the PQ plane. Both highlight a feature absent from portfolio-level models: at system level, flexibility cannot be assessed independently of network representation.

Ultimately, system-level modelling acts as a decision-support function, informing planning, procurement and regulatory choices while making system-wide trade-offs explicit. In doing so, it closes the loop from physical feasibility to portfolio deliverability, and finally to flexibility services that are both operationally effective and system-relevant. These three modelling layers establish the conceptual scaffold for FaaS assessment; the following sections turn to the data they require and the validation procedures that make their outputs trustworthy.

6.2 Data requirements, interoperability and digital infrastructure

The deployment of FaaS relies on the existence of a robust digital layer capable of connecting flexibility providers, aggregators, market platforms, system operators and end users. Regardless of the underlying technology flexibility can only become operational when it can be observed, communicated, activated, measured and verified[63]. Digital infrastructure therefore represents the operational backbone of FaaS, transforming the technical flexibility potential of assets into a reliable and tradable service, as detailed in Table 16.

The increasing penetration of distributed energy resources leads to a rapid growth in the volume and heterogeneity of data required to operate flexibility services. Relevant information includes generation and consumption profiles, state variables (e.g., state of charge or thermal conditions), equipment availability, weather forecasts, market signals and network constraints. These data streams enable flexibility providers and system operators to identify available flexibility, forecast system needs, optimise activation strategies and verify service delivery. As flexibility becomes more distributed and dynamic, timeliness, accuracy and temporal granularity of data become critical performance drivers[64].

Flexibility activation requires continuous and coordinated information exchange across multiple actors and system layers. A resource can only respond to a system need if three conditions are met: (i) an activation signal is received, (ii) the local control system can implement the requested action, and (iii) the response can be measured at the relevant validation point. This applies uniformly across resource types, from building energy

[61] Savvopoulos, N., & Hatziargyriou, N. (2023). *An Effective Method to Estimate the Aggregated Flexibility at Distribution Level*. IEEE Access, 11, 31373–31383. [Online]. Available: https://doi.org/10.1109/ACCESS.2023.3262730
[62] Savvopoulos, N., Evrenosoglu, C. Y., Konstantinou, T., Demiray, T., & Hatziargyriou, N. (2021). *Contribution of Residential PV and BESS to the Operational Flexibility at the TSO-DSO Interface*. 2021 International Conference on Smart Energy Systems and Technologies (SEST), 1–6. [Online]. Available: https://doi.org/10.1109/SEST50973.2021.9543406
[63] European Commission. (2022). *Digitalising the energy system – EU action plan (COM(2022) 552 final)*. Brussels: European Commission. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52022DC0552
[64] Antonopoulos, I., Robu, V., Couraud, B., Kirli, D., Norbu, S., Kiprakis, A., Flynn, D., Elizondo-Gonzalez, S., & Wattam, S. (2020). *Artificial intelligence and machine learning approaches to energy demand-side response: A systematic review*. Renewable and Sustainable Energy Reviews, 130, 109899. [Online]. Available: https://doi.org/10.1016/j.rser.2020.109899

management systems to EV charging infrastructure, storage systems and industrial loads.

Interoperability is therefore a prerequisite for the large-scale deployment of FaaS. Flexibility resources are characterised by a high degree of technological diversity, often relying on different manufacturers, communication protocols, software platforms and operational standards. Without common interfaces and harmonised data exchange mechanisms, flexibility remains fragmented and difficult to integrate into coordinated market and system operations. Interoperability must be ensured at five complementary levels[65]:

- **Technical interoperability**, enabling devices and platforms to exchange data;
- **Semantic interoperability**, ensuring consistent interpretation of exchanged information;
- **Organisational interoperability**, supporting coordinated operation among TSOs, DSOs, aggregators, suppliers and flexibility providers;
- Contractual interoperability, ensuring that product definitions, baselines and verification rules are compatible enough across buyers for the same resource to serve multiple markets;
- Regulatory interoperability, ensuring that prequalification, telemetry and aggregation requirements do not fragment participation along national lines.

Variation in the grid stability related issues calls for a shift from semantic into technical interoperability.
Existing standards and frameworks provide a foundation for interoperability. Communication standards such as IEC 61850, OpenADR, and the Common Information Model (CIM) facilitate data exchange across different operational environments and support the integration of flexibility resources into multiple market structures. The increasing development of European energy data spaces and common digital architecture is expected to further improve interoperability, reduce integration costs and facilitate the participation of smaller actors in flexibility markets.

Smart meters, advanced metering infrastructure, IoT devices, cloud-based platforms and energy management systems constitute key enabling technologies for FaaS. These technologies provide the visibility and controllability required to manage distributed flexibility resources in real time. Aggregators rely on this digital infrastructure to coordinate large portfolios of assets and transform individually small flexibility contributions into services that can participate in balancing markets, congestion management schemes or ancillary service provision. At the same time, artificial intelligence and advanced analytics are increasingly being used to improve forecasting accuracy, optimise flexibility activation and support operational decision-making under uncertain conditions[66]. The performance of these models degrades as the conditions under which they were estimated change, so their outputs have to be validated continuously against realised operational performance rather than only at deployment.

Digital twins are also emerging as valuable tools within flexibility ecosystems[67]. They enable the simulation and optimisation of flexibility strategies before implementation. They can thus support network planning, evaluate flexibility potential, assess operational impacts and improve the overall efficiency of flexibility procurement and activation processes.

The increasing digitalisation of flexibility services raises critical requirements in terms of cybersecurity and data governance.[68] A growing number of connected devices increases the exposure of energy systems to cyber

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[65] European Commission. (2017). *European Interoperability Framework – Implementation Strategy (COM(2017) 134 final)*. Brussels: European Commission. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex:52017DC0134

[66] Shahid, A., Ahmadiahangar, R., Rosin, A., Blinov, A., Korõtko, T., & Vinnikov, D. (2025). *Leveraging the machine learning techniques for demand-side flexibility – A comprehensive review*. Electric Power Systems Research, 238, 111185. [Online]. Available: https://doi.org/10.1016/j.epsr.2024.111185

[67] Mchirgui, N., Quadar, N., Kraiem, H., & Lakhssassi, A. (2024). *The Applications and Challenges of Digital Twin Technology in Smart Grids: A Comprehensive Review*. Applied Sciences, 14(23), 10933. [Online]. Available: https://doi.org/10.3390/app142310933

[68] European Commission. (2023). *Commission Implementing Regulation (EU) 2023/1162 of 6 June 2023 on interoperability*

threats, making secure communication channels, authentication mechanisms, encryption protocols and continuous monitoring indispensable[69]. At the same time, clear governance frameworks are needed to address questions related to data ownership, access rights, privacy protection and data sharing. Trust among consumers, flexibility providers, aggregators, and system operators will be a determining factor in the successful expansion of flexibility markets.[70]

Ultimately, the future development of FaaS depends not only on the deployment of flexible technologies, but also on the digital infrastructure that enables these technologies to interact efficiently across the energy system. Investments in this area will therefore be as important as investments in physical flexibility assets themselves.

Table 16 - Digital and data layers enabling FaaS

Layer	What it represents	Key questions	Typical elements	Main actors
Data acquisition and observability	Measurement and sensing of asset and system states	What is happening in real time? What flexibility is available?	Smart meters, IoT sensors, telemetry systems, SCADA data, edge devices	Asset owners, DSOs, TSOs
Communication and interoperability	Data exchange across devices, platforms, and actors	Can systems communicate reliably and consistently? Is data understood uniformly?	IEC 61850, OpenADR, CIM, APIs, data platforms	Technology providers, aggregators, system operators
Control and activation	Translation of service requests into asset-level actions	How is flexibility activated and coordinated? Are constraints respected?	EMS/BEMS, aggregators' control platforms, optimisation engines	Aggregators, service providers
Data processing and analytics	Transformation of raw data into forecasts and decisions	How is flexibility forecasted, optimised, and validated under uncertainty?	Forecasting models, AI/ML tools, optimisation algorithms, digital twins	Aggregators, researchers, platform operators
Governance and cybersecurity	Rules ensuring secure, fair and trusted data usage	Who owns the data? Is it secure, auditable, and compliant?	Encryption, authentication, data governance frameworks, regulatory rules	Regulators, TSOs/DSOs, market operators

requirements and non-discriminatory and transparent procedures for access to metering and consumption data. Official Journal of the European Union. [Online]. Available: https://eur-lex.europa.eu/eli/reg_impl/2023/1162/oj/eng

[69] Ismail, F. B., Al-Faiz, H., Hasini, H., Al-Bazi, A., & Kazem, H. A. (2024). *A comprehensive review of the dynamic applications of the digital twin technology across diverse energy sectors*. Energy Strategy Reviews, 52, 101334. [Online]. Available: https://doi.org/10.1016/j.esr.2024.101334

[70] European Union. (2023). *Regulation (EU) 2023/2854 of the European Parliament and of the Council of 13 December 2023 on harmonised rules on fair access to and use of data (Data Act)*. Official Journal of the European Union. [Online]. Available: https://eur-lex.europa.eu/eli/reg/2023/2854/oj/eng

6.3 Validation methodologies and performance assessment[71][72]

Validation is the mechanism that turns flexibility from a declared capability into a credible service. In FaaS, validation must therefore be designed as a structured process that verifies *what was delivered* against contractual commitments and evaluates *what system effect* was achieved against operational objectives. These two questions are analytically distinct and must be therefore treated separately in both methodology and stakeholder accountability. Two validation levels can be distinguished:

- **Asset-level validation (delivery validation)** asks: *Did the resource deliver what it committed to deliver?* It concerns whether a service providing unit (SPU), or aggregated service providing group (SPG), physically delivered its contracted volume and trajectory, including ramp rate, response latency and sustained duration. Accountability for delivery performance rests primarily with the service provider and/or aggregator, who control the assets and define the activation strategy.
- **Service-level validation (outcome validation)** asks: *Did that delivery produce the intended system effect?* It concerns whether the delivered flexibility actually achieved the objective for which it was procured, e.g., congestion relief, frequency support, voltage regulation, under the prevailing network and system conditions. Accountability for outcome assessment rests with the system operator, who defines the service, issues the dispatch signal and has the network observability required to evaluate system-level impact.

The two validation levels above concern what a resource delivered and what effect that delivery produced. A third question is regarding whether the used models remain valid over time. Forecasting and optimization models are estimated on historical conditions, and their accuracy degrades as those conditions change, through rising shares of variable generation, evolving tariff structures, and also new load categories such as electric vehicles and heat pumps. A further mechanism is specific to flexibility services: repeated participation alters the consumption patterns from which baselines were derived, so that a model can degrade as a consequence of its own use. In addition, a baseline model that has drifted produces a systematic, one-directional transfer of value between the service provider and the procuring operator, invisible to both unless it is measured. Model validity is therefore a condition of contractual fairness and forecast quality.

Continuous validation should accordingly be treated as part of the validation framework and specified as:

- comparison of model outputs against realized operational performance;
- monitoring of forecast and baseline error against thresholds agreed in advance, with defined consequences when they are exceeded;
- periodic re-estimation at a stated frequency;
- versioning of models so that any past settlement can be reconstructed against the model actually in force at the time.

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[71] ACER. (2025). *Recommendation No 01/2025 on the reasoned proposal for the establishment of the Network Code on Demand Response*. Ljubljana: European Union Agency for the Cooperation of Energy Regulators. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Recommendations/ACER_Recommendation_01-2025_Demand_Response_Network_Code.pdf

[72] EU DSO Entity. (2026). *Report on Distributed Flexibility – Practices and Markets for Local Services*. Brussels: EU DSO Entity. [Online]. Available: https://eudsoentity.eu/wp-content/uploads/2026/02/Report-on-Distributed-Flexibility-Practices-Markets-for-Local-Services-2.pdf

A second structural distinction concerns the timing of validation:

- **Ex-ante validation** occurs *before* service delivery and includes pre-qualification, capability testing and simulation-based scenario analysis.
- **Ex-post validation** occurs *after* activation and encompasses measurement, verification and performance scoring against contracted baselines.

Both phases are necessary and should be designed as an integrated loop: ex-post validation should feed back into ex-ante calibration, progressively updating qualification assumptions, reliability margins and operational constraints as empirical evidence accumulates.

Asset-level validation: baselines as the counterfactual reference

Asset-level verification requires a counterfactual reference: *What would the SPU have injected/withdrawn in the absence of activation?* As discussed in the modelling section, baseline modelling is not a mere accounting add-on but a structural component of service definition and accountability: both delivery verification and settlement depend on the comparison between metered data and the agreed baseline.

Baseline methods must therefore balance two needs: they must be *technically robust* (to prevent systematic bias and strategic distortion) while remaining *operationally implementable* across heterogeneous SPUs and metering configurations.

A baselining methodology should adhere to the following principles:

- **Consistency**: the method should be stable and repeatable, avoiding arbitrary changes across events or periods.
- **Data-informed design**: where possible, baseline should be grounded in metered data and/or justified forecasts.
- **Transparency and traceability**: assumptions, inputs and computational steps must be documented and reproducible.
- **Auditability**: the method must enable independent verification as part of periodic performance reviews.

These principles translate the broader requirements highlighted earlier – robustness to contextual drivers, bias control and defensibility under stakeholder scrutiny – into concrete validation practice.

Baselining can be implemented through different families of approaches, depending on product design, data availability and metering constraints:

- **Provider-nominated ex-ante baseline**: the service provider submits, before the activation event, the expected consumption or generation profile of the SPU in the absence of flexibility activation (subject to consistency checks).
- **Historical (recent-measurement) baseline**: the baseline is computed from recent SPU measurements, with or without near real-time adjustments.
- **Pre-/post-activation measurement baseline**: the baseline is inferred from measurements immediately before and/or after activation, when suitable and consistent with service rules.
- **Control-group (representative population) baseline**: the baseline is derived from measured profiles of comparable non-activated SPUs (e.g., similar renewable units or customer segments with analogous consumption patterns).

The most suitable method should be selected and duly checked over time according to:

- SPU scale (e.g., domestic vs industrial & commercial),
- metering arrangement (e.g., point of connection, boundary-point smart metering system, dedicated metering for controllable units),
- technology type (the resource class underpinning flexibility provision),

- service direction and product type (e.g., demand turn-down / generation turn-up vs demand turn-up / generation turn-down).

Finally, baselining and settlement should be performed at the SPU level (the service validation point), not necessarily at the level of individual controllable devices. In line with NCDR definitions[73], an SPU is the aggregation level used for settlement and may comprise multiple controllable units or a single unit, depending on implementation.

Service-level validation: verifying system impact and linking to planning

The system operator should verify whether the delivered flexibility achieved the expected system effect, such as reducing congestion, maintaining voltage within limits or supporting system stability. This can be achieved primarily through in-field monitoring methods, such as observability. It requires an ex-ante clear definition of a successful outcome for each service and where the effect is expected to be visible in the system.

Service-level validation should be linked to ex-ante planning. In particular, network development plans (NDPs) are considered as a primary source for SOs to identify flexibility needs and provide medium- to long-term visibility. The planning layer can help in defining ex-ante scenarios, including where and when flexibility is expected to deliver its value. At the same time, it should support ex-post evaluation verifying real outcomes of flexibility services. In case of ancillary services, the selection of flexibility services should be supported by a system-level cost-benefit analysis, comparing flexibility with alternative solutions (including traditional grid investment or other operational tools) and selecting the most efficient combination that shall consider risk of not solving the expected criticalities.

A practical challenge relevant to both delivery and outcome validation is the presence of *compensation effects*. These occur when, during an activation window, other devices behind the same service validation point change their injection/withdrawal in a way that offsets the controllable unit's action. As a result, the net impact observed at the SPU boundary can be reduced or even cancelled, affecting both settlement quantities and the measured system outcome.

[73] ACER. (2025). *Recommendation No 01/2025 on the Network Code on Demand Response – Annex I: Amended Demand Response Network Code*. Ljubljana: European Union Agency for the Cooperation of Energy Regulators. [Online]. Available: https://www.acer.europa.eu/sites/default/files/documents/Recommendations_annex/ACER_Recommendation_01-2025_DR_NC-Annex1_Amended_DR_NC.pdf

For this reason, validation frameworks, discussed also in Table 17, should explicitly define how compensation effects are treated in both asset-level settlement and service-level outcome assessment, ensuring that what is ultimately verified is the flexibility effectively delivered to the system operator at the relevant interface.

Table 17 - Validation layers for FaaS

Validation layer	What it represents	Key questions	Main actors / accountability
Asset-level (delivery validation)	Physical delivery of the contracted service at the SPU/SPG boundary (volume, dynamics, duration)	Was the contracted flexibility delivered as declared (MW/MWh, ramp, latency, sustain)? Was delivery compliant with technical/operational constraints?	Service provider / Aggregator (primary accountability for delivery and control actions)
Service-level (outcome validation)	System impact of the activation under real network and operating conditions	Did the activation produce the intended system effect (congestion relief, voltage support, frequency response)? Where and when was the effect observable?	System operator (TSO/DSO) (primary accountability for outcome definition and assessment, based on observability)
Ex-ante validation (qualification)	Pre-delivery evidence that a resource/portfolio can provide the service	Is the SPU/SPG eligible and capable under representative scenarios? Are metering, telemetry, controllability and product requirements satisfied?	Provider/Aggregator (provide evidence) + System operator (sets requirements and approves qualification)
Ex-post validation (verification & scoring)	Post-delivery measurement, verification, and scoring of performance and impact	What was actually delivered and what was actually achieved? How should performance translate into settlement and future reliability margins?	Provider/Aggregator (delivery evidence & data provision) + System operator (event evaluation and outcome verification)

7. MARKET INTEGRATION

7.1 Flexibility services within existing electricity markets

Implementing FaaS for energy storage assets in existing electricity markets presents several challenges, mainly because most market designs were originally developed around conventional generation and demand rather than fast, bidirectional and highly controllable resources. In addition, existing market products may not fully capture the technical capabilities of storage, such as fast response, short-duration flexibility, locational support, or stacked service provision across different markets. As a result, storage operators may face barriers to accessing multiple revenue streams, while system operators and market platforms may lack the mechanisms needed to coordinate these services efficiently.

7.1.1 Energy Markets (EMs)

In energy markets, one of the main challenges for implementing FaaS is that existing market structures are still largely designed around conventional generation, supplier-based demand forecasting and relatively predictable trading positions. This creates complexity in bidding strategies, settlement, network tariffs, regulatory classification and the avoidance of double charging. ENTSO-E[74] explicitly identifies double charging of network tariffs, limited access to ancillary services, regulatory uncertainty and limited long-term revenue visibility as barriers to merchant storage investment, while also noting that storage revenues often depend on stacking value across day-ahead, intraday and ancillary services markets. ACER's Framework Guideline on Demand Response[75] also confirms that future EU rules need to cover aggregation, energy storage and demand curtailment, with the objective of supporting market integration, non-discrimination, effective competition and efficient market functioning. Nevertheless, the potential is significant: storage-based FaaS can improve market efficiency by shifting energy across periods, absorbing surplus renewable generation, reducing curtailment and supporting more efficient operation of day-ahead, intraday and balancing markets.

7.1.2 System Services Markets (SSMs)

In system services markets, FaaS has strong potential because energy storage assets can provide fast, accurate and controllable flexibility services, including balancing, frequency-related services and reserve activation. ENTSO-E[76] highlights that utility-scale storage can contribute to system security, affordability and decarbonisation, especially as higher shares of variable renewable energy increase the need for flexibility and system-aligned operation. However, existing market arrangements may not fully value storage capabilities, particularly when products include restrictive duration requirements, prequalification rules, availability obligations or limited opportunities for multi-service operation. These issues are consistent with ENTSO-E's identification of limited access to ancillary services and the need for non-discriminatory access to all value streams, including balancing, ancillary services and congestion management. At European level, the development of harmonised balancing platforms and market rules, including initiatives such as MARI and

[74] ENTSO-E. (2025). *Policy Paper on Market Design for Utility-Scale Energy Storage*. Brussels: European Network of Transmission System Operators for Electricity. [Online]. Available: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Reports/2025/ENTSO-E_pp_market_design_utility_scale_energy_storage_Short_Summary_251215.pdf
[75] ACER. (2022). *Framework Guideline on Demand Response*. Ljubljana: European Union Agency for the Cooperation of Energy Regulators. [Online]. Available: https://acer.europa.eu/sites/default/files/documents/Official_documents/Acts_of_the_Agency/Framework_Guidelines/Framework%20Guidelines/FG_DemandResponse.pdf
[76] ENTSO-E. (2025). *Market Report 2025*. Brussels: European Network of Transmission System Operators for Electricity. [Online]. Available: https://eepublicdownloads.blob.core.windows.net/strapi-test-assets/strapi-assets/entso-e_Market_report_2025.pdf

PICASSO, demonstrates the ongoing evolution of balancing markets, but also underlines the need for storage and flexibility providers to be integrated into increasingly coordinated and standardised market frameworks.

7.1.3 Local Flexibility Markets (LFMs)

The increased penetration of renewable energy sources, the electrification of the system and efforts to achieve the European decarbonisation target have led all European Union countries to recognise the need to find solutions for grid flexibility. For these reasons and given that expanding existing grids is a time-consuming and costly solution, local flexibility markets (LFMs) have emerged as a market-based mechanism that allows network operators to procure the flexibility they need precisely where they need it.

An LFM is a marketplace in which network operators procure flexibility services with a topological character. On the demand side are the procurers, which include DSOs and TSOs. On the supply side are the providers (FSPs), which include consumers, aggregators, producers, storage operators and community or residential resources. Platform operators and owners depend on the executive platform characteristics. This highlighted the fact that the procurement of flexibility is framed as a "for-profit" business with a win-win outcome for social welfare: the network operator avoids or defers a costly investment, the FSP earns a revenue stream, and the system operates more efficiently.

The following figures illustrate the operation and participation of LFMs and LFPs.

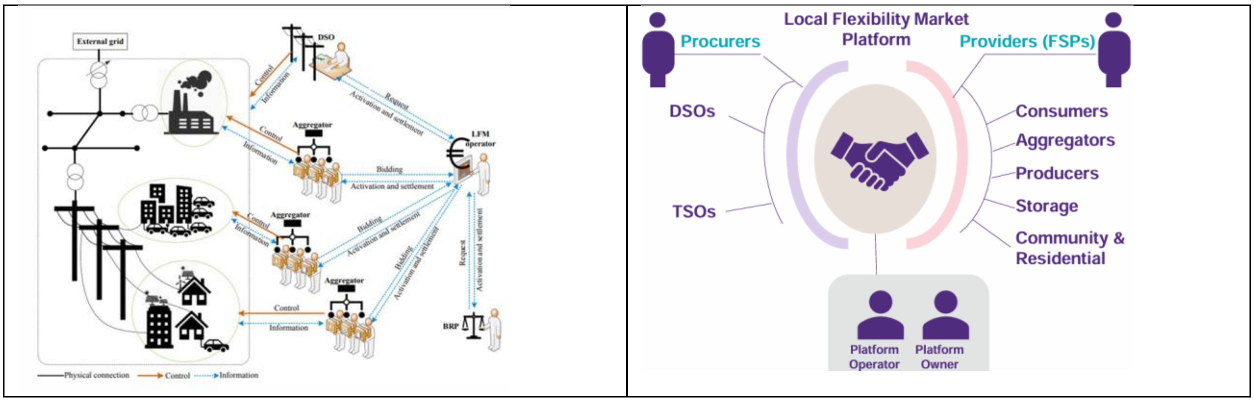

Figure 15 - Operation and participation of: (left) LFMs, (right) LFPs

LFMs offer a broad set of operational and strategic benefits:

- **Enhanced grid management:** efficient matching of supply and demand, active congestion management and enhancement of network work planning.
- **Cost efficiency:** investment deferral in grid reinforcement and operational savings through the avoidance of RES curtailments.
- **Integration of renewable energy:** increased RES penetration and further utilisation of distributed generation capacity.
- **Enhanced market participation:** new revenue streams for market participants and deeper engagement of consumers and prosumers.
- **Resilience and security:** localised control of energy resources and reduced system reliance on centralised generation.
- **Environmental benefits:** reduced network losses and emissions, and increased integration of renewable sources.
- **Innovation and technology adoption:** incentives for the deployment of new technologies across RES, energy storage and demand response.

The deployment of LFMs is, however, subject to a few significant challenges:

- **Technical and technology:** grid and market integration of flexibility platforms, data management and interoperability, technology maturity, standardisation and cybersecurity.
- **Market:** concerns about arbitrage between locational products and wholesale markets, and challenges related to sequential congestion and balancing responsibilities.
- **Regulatory and policy:** developing and harmonising regulations that support LFMs, providing appropriate incentives to DSOs and TSOs, and aligning market rules with grid codes.
- **Market design:** stakeholder coordination, platform scalability, product definition, auction formats and the achievement of adequate market liquidity.
- **Social and behavioural:** consumer engagement, behavioural change and the building of participants trust.

7.1.4 Local Flexibility Platforms (LFPs)

The European legislative framework has progressively formalised the role of LFMs, establishing their procurement as a binding obligation rather than an optional innovation. Directive (EU) 2019/944, Article 32, obliges Member States to provide a regulatory framework that allows and incentivises DSOs to procure flexibility services — including congestion management — as an alternative to traditional network investment, and Article 31(3), as amended by Directive (EU) 2024/1711, makes the recognition of those costs in distribution tariffs explicit while allowing regulatory authorities to set performance targets. The amended Electricity Regulation further requires tariff methodologies to reflect both capital and operational expenditure. Implementation, however, remains heterogeneous: flexibility costs are treated either as pass-through or as controllable OPEX, with no prevailing practice across Member States. Whether a platform moves beyond the pilot stage therefore depends less on its technical design than on whether the procuring operator can recover the cost of flexibility and is rewarded for the resulting network outcome. The six platforms reviewed below are read against this background.

7.1.4.1 Detailed analysis of leading local flexibility platforms

Across Europe, a significant number of local flexibility platforms have been developed, at varying levels of maturity. Where the regulatory framework provides adequate incentives and cost-recovery mechanisms, platforms have progressed to full commercial operation. On the other hand, where regulation remains underdeveloped, initiatives have stalled at the pilot stage. The following figure shows exactly this.

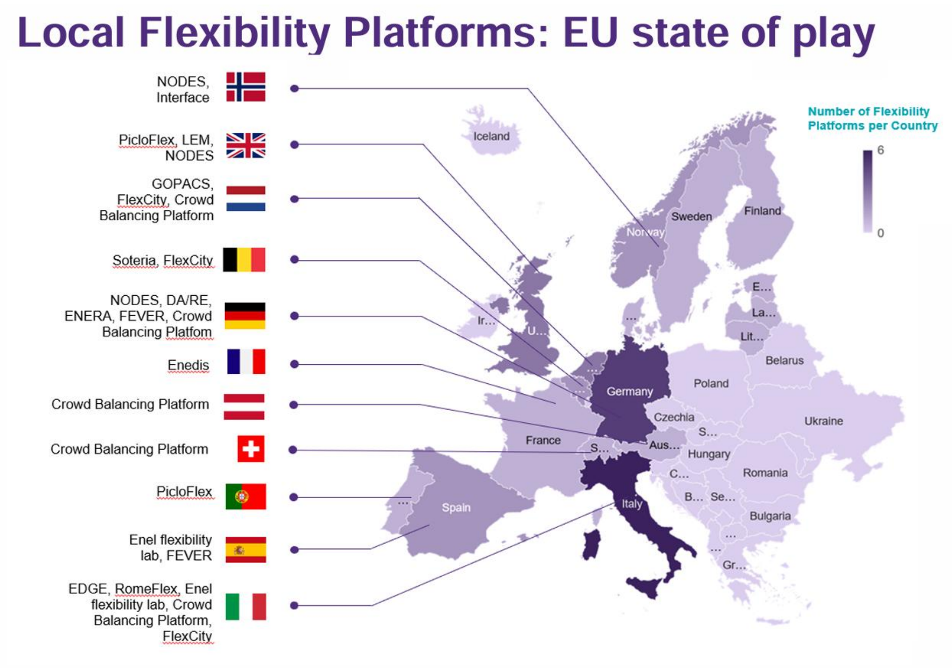

Figure 16 - Local Flexibility Platforms in Europe

Although all local flexibility platforms share the same fundamental purpose which is connecting network operators with FSPs to procure location-specific flexibility, they differ substantially across several dimensions. More specifically, the LFPs utilised in each country have been designed with certain country-specific characteristics taken into account.

<u>ENERA (Germany)</u>

ENERA began as an R&D project in 2018 and as a joint initiative between the power exchange EPEX SPOT, the local utility EWE AG, the German TSO TenneT, and the German DSOs Avacon Netz and EWE NETZ. The pilot was finalised in 2021. It never reached a commercial phase and no version of ENERA is currently operational. The pilot did not move beyond the pilot stage due to the absence of appropriate regulation: the German regulatory regime is cost-based and does not envisage market-based approaches, which made it difficult for such an initiative to survive.

- **Needs and products.** The platform was designed to enable flexible solutions that avoid the curtailment of excess wind energy, and its focus was therefore on congestion management. Network operators procured flexibility while flexibility providers submitted offers, through a continuous matching of upward and downward energy activations. The most economically competitive FSPs were activated in the actual operating interval. The offers in ENERA consisted uniquely of activation payments (no capacity payment was considered). Network operators requested activations in specific areas of the congested grid (for example, a downward activation to absorb wind oversupply) for specific time windows.

- **Role of the DSO and incentives.** Network operators bought flexibility in the intraday timeframe to proactively alleviate congestion. There were, however, no financial incentives for the DSO at the time of the project. A key challenge caused by German regulation is that these platforms qualify as market-based redispatch and therefore do not qualify as expenses that can be recovered through tariffs. For this reason, the project only materialised within the tight boundaries of a regulatory sandbox. Germany experiences structural congestion, so market-based congestion management raises concerns over INC-DEC gaming. The project participants noted that there would be incentives to adopt such a platform if a TOTEX remuneration approach were followed, allowing platform expenses to be recovered. Germany does, however, have best-effort regulations to avoid curtailments and standards of service that DSOs must satisfy (for example, an obligation to limit loss of load to a certain number of hours), which motivated the development of flexibility initiatives.

- **Coordination and market relations.** ENERA ran in the intraday timeframe. DSOs and the TSO were expected to communicate bilaterally when activating an offer, in order to avoid conflicts, since an upper-level activation may cause lower-level congestion. Market parties had the option to submit offers with the same underlying asset to different markets; the responsibility to avoid double activation lay with the flexibility provider. Access to the trading platform was standardised, and market parties could use the same API they use for intraday trading. ENERA coexisted in Germany with other initiatives (such as NODES) operating in different regions, with no reported coexistence issues.

- **Ownership and business model.** During the pilot phase, EPEX SPOT ran the platform. The principle for a commercial version was that its operation would be paid for by the system operators, while a neutral third party would run the platform.

<u>**NODES (Norway, Sweden, Canada)**</u>

NODES started in early 2018 as a joint project between the Norwegian utility (DSO) AgderEnergi and the power exchange Nord Pool. It began with three pilots — one in Norway with the DSO AgderEnergi Nett, and two in Germany with the DSOs Mitnetz Stom and WEMAG Netz. The project has since moved to a commercial phase and is live in Norway, Sweden and Canada.

- **Needs and products.** The Norwegian DSO mainly suffers from growing loads that could require an upgrade of the network. The platform supports two products, ShortFlex and LongFlex, both targeting congestion management and both referring to an upward or downward activation of active power. ShortFlex relates to activations within a pre-defined fixed time period and entitles providers only to activation payments. LongFlex allows automatic activations within a defined time horizon and qualifies for both capacity (availability) and activation payments. The platform is accessible through the NODES website, where flexibility providers specify their offers using a wide range of technical and financial parameters, and buyers filter the catalogue to select the cheapest offer that fulfils their needs through a continuous matching process.

- **Role of the DSO and incentives.** Network operators procure local flexibility in NODES. The rationale for participation is structural: the buildout of network infrastructure cannot keep pace with the resources being added to the edges of the network, and EU regulation requires the development of flexibility platforms.

- **Coordination and market relations.** NODES is foreseen to operate across the full-time horizon, from long-term to intraday. It does not interact directly with other wholesale markets. Since the project remains very generic in terms of product definitions, interfacing it with other wholesale markets is hardly possible.

- **Ownership and business model.** The platform was originally owned and developed by Nord Pool. Ownership has since separated and passed to an independent organisation called NODES. The business model includes subscription fees financed as a percentage of each transaction, with country-specific arrangements. Depending on the maturity of the project, participation fees can be levied on both network operators and FSPs. In mature projects it is envisioned that FSPs do not pay fees and that all operational costs are covered by the system operator.

<u>**PicloFlex (UK, Italy, Ireland, USA, Portugal, Australia)**</u>

PicloFlex began as a pilot project in June 2018 with funding from the UK Government Department for Business, Energy & Industrial Strategy (BEIS), with all UK DSOs involved in the pilot phase. It was launched as a commercial offering in March 2019 and is now active in the UK, Italy, Ireland, the USA and Portugal. The platform has over 300,000 registered flexible assets, more than 2.6 GW of flexible capacity procured and €86 million of flexible contracts awarded, making it one of the most commercially mature solutions reviewed.

- **Needs and products.** The needs covered are mainly focused on congestion management, with additional needs in certain countries (such as the UK) including investment deferral, the enhancement of network reliability and supporting the re-energisation of the network. The platform consists of closed-gate auctions for mainly downward energy activations. Tenders typically consist of long-term contracts, which can take place years ahead (reaching up to seven years ahead), and include both reservation and activation payments through FSP bids; the platform does not support short-term contracts. Tenders are organised per constraint area, so all flexible resources within a predefined geographical area can compete, and a default baseline is established on representative historical data.

- **Products in the UK.** In the UK, four products are defined: the Secure Power Service (procuring a change in input/output to prevent a network from exceeding its firm capacity, aimed at investment deferral); the Sustain Power Service (a change in provider input/output based on near-real-time network conditions, aimed at congestion management); the Dynamic Power Service (delivering an agreed change in output following a network abnormality, aimed at enhancing reliability); and the Restore Power Service (instructing a provider to stop consuming or reconnect to support faster load restoration, aimed at re-energisation). In Italy's EDGE pilot, which uses Piclo, three products are offered (active power, reactive power and emergency).

- **Participation and parameters.** The platform performs an automatic pre-qualification for every flexibility asset (verifying location, voltage level, etc.), after which DSOs perform a deeper screening based on technical and regulatory questionnaires; the qualification process lasts around 14 days. The product parameters include minimum flexible capacity (minimum bid size 10–50 kW), minimum use, minimum use duration capability, maximum ramping period, availability agreement period and use instruction notification period.

- **Role of the DSO, ownership and incentives.** The platform is owned and operated by Piclo, a UK-based software company which sells a licence to DSOs to use PicloFlex. The DSO procures flexibility, is involved in the qualification criteria of the FSPs, and pays an annual subscription fee to access the software, while FSPs participate free of charge. Piclo offers modular services (such as auction management and settlement) that can be procured in parts. Piclo recommends a TOTEX regulatory approach: in the UK, DSOs are already subject to TOTEX remuneration, which allows them to recover platform expenses and provides a clear incentive for flexibility. Piclo is not directly regulated but is regulated indirectly, as it operates flexibility markets on behalf of the system operator. Piclo is expected to introduce a new product, PicloMax, to allow FSPs to access multiple electricity markets. The following figure illustrates the regulatory model of PicloFlex and the contractual relationships between system operators, the platform and FSPs.

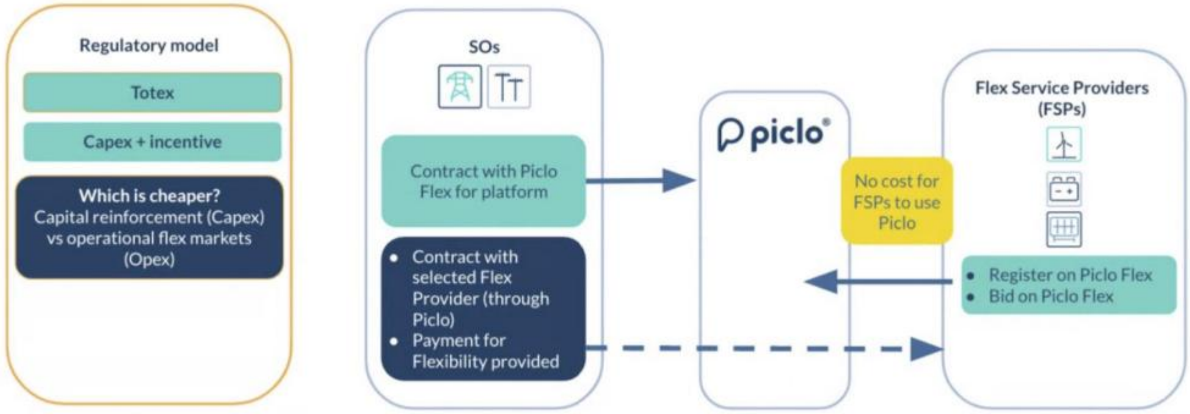

Figure 17 - Regulatory model of PicloFlex and the contractual relationships between system operators, the platform and FSPs

GOPACS (Netherlands)

GOPACS is one of the first TSO–DSO coordination platforms implemented to solve network congestion. The project started in September 2018 as a joint effort between the Dutch TSO TenneT and the Dutch DSOs Enexis, Liander, Rendo, Stedin and Westland Infra. It is in a commercial phase: as of March 2021, over 90 GWh of flexibility had been procured via GOPACS by TenneT, and since September 2020 a further 110 MWh had been procured by the DSO Liander.

- **Needs and operating principle.** GOPACS covers congestion management, but it is not the flexibility platform itself. Instead, it acts as an intermediary between the needs of network operators and existing markets. It is connected to the national intraday markets of the Netherlands (in particular the Energy Trading Platform Amsterdam (ETPA)) and to the EPEX Spot intraday market. Its main purpose is to foster an environment where TSOs and DSOs work together, ensuring that solving congestion for one operator does not cause a problem for the other, and that a congestion solution does not create a balancing problem for the TSO.

- **Products and services.** GOPACS enables the trading of upward and downward energy activations matched through continuous trading. The procurement of flexibility activation is a combination of matching two orders (a buy order and a sell order) packaged into a standardised product known as IDCONS. Grid operators pre-announce their flexibility needs (volume, time, duration and direction) for solving congestion in specific areas, defined through postal codes or regions, and these needs can be announced less than 24 hours before activation. To participate, market participants require an electricity connection in the congestion area, and a flexibility offer is placed on one of the connected trading platforms (ETPA or EPEX SPOT) with an associated locational tag. The acceptance of an offer may not disrupt the balance of the electricity grid at the national level: a reduction of generation within the congestion area is combined with a sell order from a participant outside it; the system rapidly checks that this does not cause problems elsewhere, and if all signals are green the grid operators pay the price spread between the two orders, effectively implementing a pay-as-bid scheme.

- **Ownership and business model.** GOPACS is a foundation set up by TenneT and five DSOs. Participation is divided into equal parts, with 50% for the TSO and 50% for the DSOs (each individual DSO's share determined by its size). The participation fee structure is flexible and defined in accordance with the system operators: if they agree that FSPs pay no fees, the system operators pay for the expenses of the platform. Otherwise, costs can be shared between FSPs and system operators. Regarding payments to FSPs, there are only activation payments, no reservation payment is envisaged. To participate, an FSP must complete a qualification assessment including an agreement of participation, a technical assessment (including metering points) and a regulatory assessment.

- **Coordination and known issues.** Since GOPACS is integrated with the intraday market, it is susceptible to known market-manipulation issues. For instance, INC-DEC gaming is always a threat in congested markets with a single bidding-zone price. With respect to liquidity, the Netherlands is a small country, and flexibility services imply that the availability of resources is limited to even smaller territories. The main user of GOPACS has been the TSO TenneT, while the DSOs have procured significantly smaller volumes (the largest DSO user, Liander, having procured 111 MWh).

<u>**Enedis (France)**</u>

A public consultation was launched in late 2018 by Enedis, the main French DSO, aimed at identifying expectations and sharing the conditions for implementing flexible services. Since 2019, tenders for the procurement of flexibility have been conducted on an annual basis. The platform is in a commercial phase, although with low liquidity: in 2023, Enedis contracted only four local flexibility service providers. Enedis covers 95% of the French grid.

- **Needs and products.** The needs covered include congestion management, the enhancement of work planning and investment deferral, offered through three distinct products. The first procures flexibility as an alternative to power resupply resources before or following an incident, enabling better congestion management when conditions do not justify grid investment. For this product the FSP is remunerated by an activation payment only, since activation is expected to be rare. The second allows flexibility procurement to enhance work planning, preventing outages linked to planned work. Here guaranteed availability is critical, so remuneration includes both activation and reservation payments with penalties for non-availability. The third considers flexibility in order to defer investments, transferring the risk from grid planning to real-time grid management, and therefore also requires guaranteed availability with both activation and reservation payments.

- **Role of the DSO and incentives.** The DSO operates the platform and is responsible for identifying flexibility needs and submitting tenders annually. France, however, follows a CAPEX approach, so the regulatory incentives for these platforms are not as strong as in other national regimes, and the grid is reported to be largely stable. From a regulatory point of view there is no regulation strongly incentivising the development of flexibility solutions. The DSO has argued that flexibility would allow for a smoother environment and that, since building up infrastructure can be lengthy, flexible solutions can help, but the commercial activity remains low, with only four awarded contracts for 2023.

- **Ownership and market relations.** The Enedis flexibility platform is owned and operated by the DSO Enedis and is not integrated with other energy markets in France. It appears as the only flexibility initiative within the country. The DSO submits the flexibility needs, the characteristics of the desired product and the geographical location into the platform, while FSPs submit their offers by email directly to Enedis. Tenders are conducted once per year following a closed-gate auction format, and correspond to long-term contracts, awarded based on a legal assessment, a technical assessment (verifying that the FSP satisfies the tender specifications) and an economic assessment (where the DSO compares bids against a fallback cost threshold). Multiple FSPs can be awarded per tender.

<u>**EPEX LEM (United Kingdom)**</u>

The EPEX local energy market (LEM) project started in 2019 as a three-year pilot in Cornwall, UK, and was originally developed by Centrica. After the pilot phase, EPEX bought the initiative. The platform is in a commercial phase and is active in the UK. During the trial phase, 201 MWh of reservation contracts were concluded and 90 MWh of volume was delivered or activated.

- **Needs and products.** The needs covered correspond to congestion management, which has remained the main scope of the platform (the DSO UKPN has occasionally procured restoration, but these are a minority of cases). The platform offers closed-gate auctions for upward and downward energy activations, as well as reactive power services. It offers both long-term competitions and day-ahead auctions, and the products can include reservation and activation payments or be limited to just activation payments. For long-term procurement the DSOs conduct two long-term tenders, with contracts that may cover two to four years. The day-ahead auctions are timed to align with other national markets in the UK. A web-based graphical user interface displays upcoming tenders.

- **Role of the DSO and incentives.** EPEX runs and operates the platform, while the DSO engages as a buyer of flexibility, performing a fair amount of work to gather interest and identify potential flexibility providers. The DSO has a software contract with EPEX, and the business model consists of a fixed annual fee paid by the DSO (not volumetric), conditional on the satisfaction of the flexibility providers. There are payments for procured flexibility services and no charges to FSPs. The UK follows a TOTEX mechanism, which means there is an opportunity, for every pound saved, to return 50% to customers and 50% to DSO shareholders. Specific DSO incentives have been in place since April 2023, exposing the DSO to a regulatory incentive of about +£10 million or −£5 million depending on a performance indicator based on a stakeholder survey and on the regulator’s criteria around market development, transparency and data provision.

- **Participation and technical requirements.** The DSO allows the sourcing of flexibility from all voltage levels, buying flexibility from hundreds of sites. A wide range of assets can participate, including aggregated (mostly domestic) EV charge points, grid-scale distributed storage, gas peakers, some solar and wind resources (for down-regulation) and some industrial and commercial demand-side response. The platform is not integrated with other markets, and the metering requirements are relatively lenient since only half-hour metering is required and real-time metering is not necessary. The platform can support different dispatch approaches, from an API that FSPs can integrate into, to manual interactions such as email-based dispatch.

Common conclusion for the six platforms

The platforms selected for analysis serve the same purpose – connecting network operators with flexibility providers to supply flexibility at specific locations. However, it is easy to see that LFPs differ significantly in terms of their level of commercial success. According to this paper, the most important factors determining a platform’s success or failure are, in most cases, not technological but regulatory. Specifically, the PicloFlex, NODES, GOPACS and EPEX LEM platforms appear to have reached a good level of commercial operation, whereas ENERA never progressed beyond the pilot stage, nor did Enedis, which, although commercial, remains constrained by very low liquidity (only four contracts were awarded in 2023). The factor that perhaps plays the most important role in determining whether a platform succeeds commercially is whether the national regulatory framework provides DSOs and TSOs with the appropriate financial incentives to be interested to procure flexibility.

This pattern maps directly onto the remuneration framework in place. The most successful platforms operate in jurisdictions with a TOTEX (or equivalent cost-recovery) approach, under which operators can recover the cost of procured flexibility and, in some cases, retain a share of the savings. The United Kingdom is the clearest example: TOTEX remuneration allows DSOs to recover platform expenses, and explicit performance incentives (such as the +£10 million / −£5 million exposure introduced for the EPEX LEM buyer) translate directly into the commercial traction of both PicloFlex and EPEX LEM. ENERA, by contrast, experimented several difficulties, as under cost-based regimes these platforms are treated as market-based redispatch whose cost is not recoverable through tariffs, confining the project to a regulatory sandbox. Enedis is similarly held back by France’s CAPEX-oriented framework, which offers no strong incentive to favour flexibility over conventional grid investment.

Beyond regulation, several secondary design factors distinguish the more successful platforms. The first is the breadth and maturity of the product suite: the leading platforms move beyond pure activation payments to also offer reservation (availability) payments and longer-term contracts, which give providers revenue certainty and attract a broader base of flexible assets – PicloFlex's long-term tenders, NODES' LongFlex product and EPEX LEM's combination of long-term and day-ahead auctions are illustrative in this respect. The second is low barriers to entry for providers: the most liquid platforms charge FSPs no fees, place operating costs on the system operators and keep technical requirements proportionate (EPEX LEM, for instance, requires only half-hourly metering). The third is the governance and ownership model. Independent or neutral platform operators, whether a dedicated company such as Piclo, a power exchange such as EPEX or a jointly owned foundation such as GOPACS, appear better able to scale than initiatives tied to a single operator, as the Enedis case suggests.

Finally, the experience of these platforms raises a set of residual challenges that even the commercially successful cases have not fully resolved. Chief among them is the risk of market manipulation (notably INC-DEC gaming) in congested zones with a single bidding-zone price, a concern raised in both the German and Dutch contexts. Liquidity is a further constraint: where flexibility needs are confined to small geographical areas, as in the Netherlands, the pool of competing resources can be too thin to ensure competitive outcomes, and in GOPACS the bulk of procurement has come from the TSO rather than the DSOs.

Taken together, the evidence points to a clear conclusion: the platforms that succeed are those embedded in a regulatory framework that rewards both TSOs and DSOs for using flexibility, supported by mature product design, low entry barriers and neutral governance, while technology, though necessary, is not the binding constraint.

7.2 Flexibility products

A flexibility product is the common language between a system need and a provider response. It should be specific enough to make delivery measurable, but not so technology-specific that it excludes resources able to produce the same system effect[77]. For FaaS, it can be considered as a set of temporal, spatial, technical, data and commercial conditions that remain consistent from qualification and bidding to activation, validation and settlement.

At transmission level, products are already largely standardised through the European balancing framework. The Electricity Balancing Guideline and the System Operation Guideline define a layered set of balancing products, from frequency containment reserve (FCR) through automatic and manual frequency restoration reserves (aFRR and mFRR) to replacement reserves (RR), each with its own activation time and minimum delivery requirements. These products are traded on pan-European platforms and offer a mature, if demanding, route to market for resources able to meet the qualification thresholds.

At distribution level the picture is less settled. Local flexibility products are still being shaped, but two broad families are emerging. The first is availability or capacity-based products, where the provider is paid to stand ready and to comply with a capacity limit at a given location over a defined period; these fit planned constraints such as congestion linked to maintenance or seasonal peaks. The second is activation or energy-based products, where the provider is paid for the energy actually delivered when the DSO calls on it, which fits better with real-time or less predictable constraints.

[77] Villar, J., Bessa, R., & Matos, M. (2018). *Flexibility products and markets: Literature review*. Electric Power Systems Research, 154, 329–340. [Online]. Available: https://doi.org/10.1016/j.epsr.2017.09.005

Many European pilots combine the two, pairing a reservation fee with an activation price, and a recurring lesson is that products must be kept simple and well standardised. Overly complex or fragmented product definitions are one of the main reasons local markets struggle with liquidity: if every DSO designs its own bespoke product, providers face high entry costs and thin order books, and the market never reaches the critical mass needed to compete with conventional grid reinforcement. Converging towards a small set of clear, interoperable products is therefore as important as the products themselves.

7.3 Participation of new actors (aggregators, energy communities, small-scale assets ...)

The integration of energy communities, aggregators and small consumers into the European electricity market represents one significant institutional innovation introduced by the European Union's "Clean Energy for all Europeans" package, adopted in 2019. Within this evolving regulatory architecture, the figure of the "active customer," as established in Regulation (EU) 2019/944, complements these community-based models by recognising individual consumers as autonomous market participants capable of generating, storing, selling or sharing self-produced electricity. Taken together, these legal and institutional developments mark a deliberate shift in EU energy policy away from a centralised, supply-dominated paradigm and toward what the Commission has described as an energy union strategy in which citizens occupy a central role in the transition. However, the practical implementation of these frameworks across Member States remains uneven, raising persistent questions about regulatory consistency, market design and the real barriers to participation faced by smaller actors.

EU legislation currently recognises five legal figures that can be classified as energy communities[78]: Jointly-Acting Renewable Self-Consumers (JARSC), Renewable Energy Communities (REC), Jointly-Acting Active Customers (JAAC), Citizen Energy Communities (CEC), and Closed Distribution Networks (CDN). Each is governed by a distinct set of provisions across three legal acts — Regulation 2018/1999, Directive 2018/2001 (REDII), and Directive 2019/944 (Electricity Directive) — and while they share some common features, each has its own regulatory framework:

- JARSC: Defined and characterised mainly in Articles 2 and 21 of Directive 2018/2001.
- REC: Defined in Article 2 and further detailed in Article 22 of Directive 2018/2001. Additionally, Article 7 requires that electricity produced by both JARSC and REC be statistically accounted for, Article 15 addresses administrative procedures and regulations, and the directive also sets out Member States' obligations regarding information and training.
- JAAC: Developed in Directive 2019/944, structurally similar to JARSC but, unlike it, only implicitly defined (in Article 2) rather than explicitly.
- CEC: Defined in Article 2 of Directive 2019/944 and expanded in Article 16; Article 59 additionally outlines the duties and powers of regulatory authorities in relation to CECs.
- CDN: Fully defined within a single provision, Article 38 of Directive 2019/944.

In short, REDII governs the renewable-focused figures (JARSC, REC), while the Electricity Directive governs the broader market-access figures (JAAC, CEC, CDN), with CEC being the most extensively regulated due to its additional oversight provisions. The Citizen Energy Community is legally required to provide environmental,

[78] BeFlexible Consortium. (2024). *Deliverable D1.1 – Regulatory framework for fostering flexibility deployment: roles, responsibility of agents and flexibility mechanism designs*. BeFlexible (Horizon Europe project). [Online]. Available: https://beflexible.eu/wp-content/uploads/2024/04/BeFlexible-D1.1-Regulatory-framework.pdf

economic or social benefits to its members or to the area in which it operates, rather than pursuing financial profit as its primary objective. Crucially, the Electricity Directive does not merely tolerate these entities but actively empowers them: citizen energy communities must be able to access all electricity markets, either directly or through aggregation, on a non-discriminatory basis, while also bearing financial responsibility for the imbalances they cause within the system.

The Beflexible project[79] identifies several gaps and challenges in the EU regulatory framework for energy communities:

1. Undefined terms: Key terms like "open" and "autonomous" are used in Directives 2019/944 and 2018/2001 but never formally defined, leaving ambiguity around criteria such as participation conditions or ownership share limits.
2. Compliance metrics: There is no clear way to measure whether a community is actually meeting the environmental, social and economic purposes the directives require.
3. Heterogeneity of organisation types: The five legal figures show only subtle differences. RECs and CECs are similar except RECs are limited to renewable energy with no proximity restriction needed, while CECs cover any energy type and can offer services like EV charging. JARSC and JAAC are also nearly identical (both renewable-only, electricity-only agreements). The authors propose consolidating the five figures into three (self-consumer, community and closed network definitions) or harmonising definitions nationally under Art. 288 TFEU — though non-electric renewable communities still lack coverage entirely.
4. Vague distance/boundary criteria: Each figure defines geographic limits differently (e.g., "same building," "proximity," "confined boundaries"), but REC's boundaries are so loose a community could sprawl across regions, while CEC has no distance limit at all, risking growth into a large multi-national company. Proposed amendments include geographic-based limits (distance/area/administrative division) or grid-based limits (voltage level or transformer structure), each with trade-offs in clarity vs. technical accuracy.
5. Legal entity type: Since REC/CEC cannot have profit as their primary purpose, non-profits and cooperatives fit naturally, while limited companies would need special profit-distribution mechanisms to qualify — an issue left to national transposition.
6. REC distribution rights ambiguity: Article 22 of Directive 2018/2001 doesn't list distribution as a permitted REC activity, yet Article 22.4(e) implies RECs can't be discriminated against as distribution system operators — creating an inferred but unregulated right, unlike CECs, whose distribution role is explicitly addressed in Article 16.4 of Directive 2019/944. The authors suggest amending the directive to explicitly include distribution and cross-reference other renewable-energy directives.
7. Unbundling/role-limit gap: While Directive 2019/944 requires large DSOs to be legally unbundled from other activities (with exemptions for small distributors), no equivalent size or role limits exist for energy communities, meaning they could theoretically perform all market roles without restriction — a regulatory gap the authors say should be addressed.
8. Cross-border communities: Both directives allow cross-border CECs/RECs but don't specify implementation rules, which matters for enclaves like Llivia (Spanish enclave in France) or the Baarle-Nassau Belgian/Dutch enclaves. The authors suggest using Article 7 of Directive 2011/92/EU as a model for establishing common cross-border rules.
9. Cross-subsidy risk in tariffs: Because aggregated peak power demand is lower than the sum of individual peaks, energy communities pooling contracts pay reduced grid charges, which benefits members but potentially shifts costs onto non-member consumers. The authors call for careful tariff design to prevent this cost-shifting effect.

[79] BeFlexible Consortium, Deliverable D1.1 – Regulatory framework, op. cit.

Aggregators' roles as intermediaries that enable demand-side flexibility and small-scale generation to participate in wholesale and system service markets are envisioned precisely as channels through which communities and individual consumers can exercise their market access rights. Article 2 of Directives 2019/944 and Demand Connection Code Reg. EU 2016/1388provide the following definitions:

- Aggregation: function performed by a natural or legal person who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market.
- Independent aggregator: market participant engaged in aggregation who is not affiliated to the customer’s supplier.

In the European regulation an independent aggregator stands as “a market participant engaged who combines multiple customer loads or generated electricity for sale, purchase or auction in any electricity market, and who is not affiliated to the customer’s supplier”. Other than that, demand aggregation designates “a set of demand facilities or closed distribution systems which can operate as a single facility or closed distribution system for the purposes of offering one or more demand response services”.

Directive 2019/944 aims to give all customer types: industrial, commercial and household access to electricity markets so they can trade flexibility and self-generated electricity, while also promoting aggregation as a means to capture benefits across larger regions and foster cross-border competition. Market participants engaged in aggregation are envisioned as intermediaries linking customers to the broader market.

Two articles are particularly relevant:

- Article 17 (Demand response through aggregation): Requires Member States to facilitate demand-response participation via aggregation, including establishing transparent, non-discriminatory rules that clearly define the roles and responsibilities of all electricity undertakings and customers involved.
- Article 27: Allows Member States to strengthen the market position of household customers and small/medium-sized non-household customers by enabling voluntary aggregation of their representation, recognizing the collective bargaining benefits this can bring to smaller market participants.

The study of Fernández-García et al, 2025[80] breaks flexibility provision into six phases: preparation/prequalification, planning/forecasting, market clearing, activation, monitoring, and measurement, and maps which actors are involved at each stage before analysing the four core relationships as stated as follows.

- Aggregator–Supplier: This relationship can be contractual or non-contractual, and may involve single or dual balance responsible party (BRP) arrangements. The paper reviews three families of compensation models for both imbalances and energy transfers (regulated, contractual and corrected/no-compensation approaches), and highlights the unresolved "rebound effect" (where shifted consumption returns later, sometimes fully, as with EV charging) as a particular source of uncertainty, since only France has begun addressing it in practice.
- Aggregator–DER: The authors classify loads as industrial (large, stable, easy to aggregate) versus residential (small, variable, harder to manage, more prone to rebound effects), and categorise appliances by flexibility (non-flexible, semi-flexible, flexible). A major technical issue is establishing an accurate "baseline": the counterfactual consumption profile against which DR performance is measured, which is

[80] Fernández García, J. J., Troncia, M., & Chaves Ávila, J. P. (2025). *Empowering Energy Markets: Unraveling the Dynamics of Aggregators Relationships in Demand Response Services*. Current Sustainable/Renewable Energy Reports, 12(1). [Online]. Available: https://doi.org/10.1007/s40518-025-00254-z

vulnerable to moral hazard and adverse selection (e.g., customers gaming their baseline upward). Submetering practices and diverse pricing/contract structures (time-of-use, dynamic pricing, load capping, direct load control) add further complexity.

- Aggregator–System Operator: This covers imbalance settlement pricing (single vs. dual pricing) and the role of smart metering, noting wide variation in smart-meter rollout and time resolution across European countries (e.g., near-universal in Sweden and Spain, much lower in Portugal). Open questions remain about how precise metering needs to be and how to enable flexibility from assets lacking smart meters.
- Aggregator–Flexibility Requesting Parties: Aggregators operate across wholesale energy, congestion management, balancing and adequacy markets. The paper stresses the need for well-defined flexibility "products" (availability vs. activation, with attributes like bid size, notification time, and duration) and clear rules for "pooling" resources, distinguishing fixed responsibility (aggregator liable for the whole pool) from dynamic responsibility (liable only for activated assets), the latter being more accurate but harder to verify and more exposed to gaming.

7.4 Economic and regulatory hurdles

The largest barrier to market integration is often not a lack of technical flexibility but a weak or uncertain business case. Distributed providers face fixed costs for customer acquisition, controls and metering. In addition, also other aspects such as cybersecurity, qualification, forecasting and settlement play a significant role among these uncertainties. Local needs may occur only a few times per year, and small procurement volumes can create markets in which there is either too little competition or too little revenue to sustain providers. In addition to this, short contracts and changing product rules make investment difficult, while high penalties can discourage entry when availability is uncertain.

ACER's recent monitoring identifies recurring barriers across Member States. The most important thing is to find a way into the incomplete legal frameworks for independent aggregation, restrictive prequalification and minimum bid requirements. In addition, it is also possible to mention complex administrative processes, limited incentives for flexibility, slow smart-meter deployment, weak price signals, as well as network tariffs that discourage response[81].

Regulatory consistency and DSO incentives

A scaleable FaaS framework requires stable allocation of roles and costs. National rules should clarify the relationship between the aggregator, supplier, balance responsible party, connecting system operator and service buyer; the treatment of the energy activated; access to metering data; and responsibility for non-delivery. Network tariffs, wholesale prices and explicit service payments should be homogenised: as an example, a customer should not be paid to reduce load for congestion management while another tariff element rewards the opposite action during the same interval.

For DSOs, procurement must be compared with reinforcement on a neutral basis. Traditional revenue regulation can create a capital-expenditure bias if a physical asset enters the regulated asset base while flexibility procurement is treated as a less certain operating cost. Output-based or total-expenditure approaches can reduce this distortion[82], provided that reliability, consumer cost and long-term network needs remain protected. Flexibility should be used where it is efficient over the constraint horizon, not because it is fashionable or

[81] ACER, Recommendation No 01/2025 on the Network Code on Demand Response, op. cit.

[82] Ruiz, M. A., Gómez, T., & Chaves-Ávila, J. P. (2026). *Promoting efficiency with neutral operational/capital incentives under uncertainty: A comparison of electricity distribution remuneration schemes*. International Journal of Electrical Power & Energy Systems, 176, 111735. [Online]. Available: https://doi.org/10.1016/j.ijepes.2026.111735

because reinforcement is administratively difficult.

Sandboxes and transitional mechanisms

Regulatory sandboxes, pilot regulations and controlled demonstrations can bridge the gap between project experience and durable market rules. They are useful when an otherwise viable model cannot be tested because existing rules assume conventional suppliers, large generators or fixed network arrangements. Temporary derogations should not become private exemptions that favour one platform or allow risks to be transferred to non-participants. Transitional mechanisms can also include phased qualification thresholds, common procurement calendars, standard contracts, as well as longer availability for emerging portfolios, flexible connection agreements, cost-recovery rules for DSO trials, and public support for interoperable control and metering infrastructure. These measures should reduce first-mover risk while keeping a clear route towards competition. Public funding can support learning and shared infrastructure, but routine flexibility delivery should ultimately be remunerated through transparent market or regulated procurement rather than permanent project subsidies. The practical priority is to convert this direction into stable products, proportionate access rules, coordinated procurement and evidence-based regulation. Under these conditions, FaaS would be able to scale, especially if providers can understand the opportunity and, conversely, customers can trust the arrangement.

8. CONCLUSIONS AND EXPECTED IMPACT

This white paper has argued that the flexibility Europe needs is, to a large extent, already latent in its energy system. This is especially true in flexible generation and storage, in the thermal inertia of buildings and district heating networks, in industrial processes and in a rapidly growing fleet of electric vehicles. It is now important to build the service architecture that turns capability into a verifiable and remunerated delivery. FaaS names that architecture: a contractual layer that defines what is requested and how it is paid, a digital layer that makes activation and verification possible, and a market layer that values flexibility according to its time- and location-specific value. This final chapter draws the conclusions of the analysis, draws up recommendations for the three groups of actors that must now act, i.e., system operators, policymakers and regulators, and industry.

8.1 Role of FaaS in future European energy systems

Wind and solar overtook fossil fuels in EU electricity generation in 2025 and flexibility needs are projected to roughly double between 2025 and 2033. At the same time, Regulation (EU) 2024/1747 has made flexibility a resource that Member States must assess and may explicitly support. In this context, FaaS is not an optional refinement of market design but the operating model through which a high-RES system remains simultaneously reliable, affordable and decarbonised. Chapters 3 and 4 showed that the resource base is broad and largely in place; Chapter 5 showed that reliable delivery is a coordination problem in which activation chains, TSO–DSO models, cross-vector strategies and cybersecurity are more than a technology problem; Chapter 6 showed that trust in flexibility rests on consistent modelling, data and validation; and Chapter 7 showed that market access for storage, demand response, aggregators and energy communities is improving but remains uneven across Member States.

As a result of this white paper, it can be inferred that the binding constraint on FaaS is institutional and economic rather than technical: the weakest links are fragmented product definitions, incomplete frameworks for independent aggregation, tariff structures that send contradictory signals, and business cases that do not survive the end of pilot funding. Secondly, the three layers of FaaS are complementary: contracts without verifiable data cannot be settled, digital infrastructure without products to trade is stranded investment, and markets without dependable delivery lose the trust of system operators. Progress must therefore be coordinated across all three layers, which is why the recommendations below are addressed jointly to operators, regulators and industry.

It is worth underlining that not all technical flexibility potential is deliverable: comfort constraints, process continuity, user behaviour and rebound effects separate what assets could do from what services can promise. Conversely, flexibility is not a universal substitute for infrastructure: it defers or avoids reinforcement where constraints are local and temporally limited, but the comparison must be made on a neutral economic basis over the lifetime of the constraint.

8.2 Key recommendations for system operators, policymakers and industry and role of public funding

Against the backdrop of a continuing need for dispatchable electricity generation, flexible dispatchable power is expected to become a critical component of future integrated energy systems, encompassing generation assets, logistics infrastructure for transport and storage and final end-use applications. The accelerated deployment of large-scale and cost-effective storage solutions provides an effective means of absorbing surplus variable renewable energy during periods of low demand and making it available during periods of high residual load. This stored energy may subsequently be reconverted into electricity within hybrid energy systems, thereby providing a service functionally comparable to pumped hydropower storage and battery systems, albeit across different storage durations. Although such reconversion pathways are associated with limited round-trip efficiencies, they remain highly valuable and, in many system contexts, indispensable for maintaining security of supply and overall system reliability. The economic viability of the respective business cases will determine the cost levels, capacity contributions and technology shares through which these solutions support future electricity generation requirements.

Flexibility assets are therefore expected to play an increasingly important role in the provision of grid-stabilising services and in the development of remunerable system-service markets. These technologies are distinguished by their capability for highly flexible operation, including steep load ramps and dynamic duty cycles, and they provide additional operational benefits such as inertia provision, reactive power management and voltage and frequency support. Moreover, by integrating storage capabilities, they can form hybrid solutions that facilitate the progressive upgrading of existing generation assets while the broader technological, regulatory and market ecosystem is still being developed and deployed. It is therefore appropriate to initiate the necessary innovation activities at this stage, including technology development, standardisation, qualification for grid-service provision and the design of business models that ensure adequate remuneration. Such measures are essential for preparing and upgrading the power generation portfolio within the timeframe required for the wider transformation of the energy system.

Operational integration is the step that turns flexibility from a technical potential into a reliable system service. In the context of FaaS, flexible resources must not only be available, but also coordinated, activated, monitored, validated and protected through secure and interoperable processes. FaaS requires a complete operational chain: system needs must be identified, flexibility requirements must be clearly specified, resources must be checked against network constraints, activation must be coordinated between relevant actors and delivery must be validated both at asset level and system level. TSO-DSO coordination is particularly important as future flexibility will be located at distribution grids while also contributing to transmission-level needs. Future European flexibility frameworks should explicitly recognize DSOs not only as facilitators of flexibility markets, but also as active procurers and operators of local flexibility services for congestion management, voltage support, hosting capacity enhancement and optimization of network investments. Combining value streams also raises a governance question that current arrangements leave unresolved. Enabling a single resource to serve several markets requires a party with an explicit mandate to make this possible reconciling prequalification, metering, baselining and settlement across services, and arbitrating conflicting activations. European frameworks do not at present assign that lead role unambiguously. Whether it falls to the aggregator, the market operator, the DSO acting as neutral market facilitator, or a dedicated function, is a choice that should be made explicitly at national level rather than left to emerge from practice. Clear coordination models are therefore required to avoid conflicting activations, local congestion, voltage issues or unobservable impacts on system balancing. Hybrid and cross-vector solutions further increase the value of FaaS by linking electricity with heat, mobility, hydrogen, storage and other energy vectors, and require advanced operational planning and control.

The main recommendations are to define FaaS products with clear operational requirements, including location, volume, duration, response time, telemetry and validation rules; establish transparent TSO–DSO coordination procedures; prioritise interoperability through common data models and secure communication protocols; integrate hybrid and cross-vector flexibility into planning and operation; and embed cybersecurity and resilience by design through authentication, auditability, fallback operation and incident response. FaaS can support renewable integration, congestion management, system resilience and more efficient use of infrastructure, if flexibility is embedded in a secure, coordinated and validated operational framework.

Public funding mechanisms will be essential to accelerate the development, demonstration and market introduction of flexible dispatchable power technologies and associated hybrid energy systems. Targeted capital expenditure support can reduce initial investment barriers, enable industrial-scale demonstration, and support the establishment of manufacturing, storage and conversion infrastructure. In parallel, operating expenditure support can address early market imperfections by compensating for higher operating costs, efficiency losses, fuel price differentials and the still insufficient monetisation of system services during the initial ramp-up phase.

An effective public funding framework should therefore combine CAPEX-oriented instruments with OPEX-based mechanisms in a complementary manner. CAPEX grants, concessional loans, guarantees and risk-sharing instruments are particularly relevant for reducing technology and construction risks, improving bankability and enabling final investment decisions for projects with high strategic relevance. OPEX support, including contracts for difference, availability of payments, production-based premiums or remuneration for verified system-service provision, can create predictable revenue conditions and reduce exposure to volatile market prices. Such instruments are especially important where the societal value of flexibility, resilience, inertia, grid support and security of supply is not yet fully reflected in existing electricity market designs.
The design of these funding schemes should be technology-open, performance-based and aligned with long-term decarbonisation objectives.

In this context, European and national funding programmes should be coordinated more closely across the full innovation chain, from research and pilot-scale validation to industrial deployment and early market operation. Instruments such as innovation grants, state-aid-compatible funding schemes, auctions and contract-based support mechanisms can jointly reduce investment risks and accelerate the establishment of viable markets for flexible, low-carbon dispatchable capacity. By combining CAPEX and OPEX support in a coherent policy framework, public funding can help to transform strategically necessary technologies from isolated demonstration projects into bankable, scaleable and market-relevant components of a resilient future energy system.

8.3 FaaS standardisation for enabling a cost-effective energy transition

FaaS can play a key role in enabling a cost-effective transition towards a decarbonised energy system by unlocking flexibility from distributed energy resources, demand-side response, energy storage, electric vehicles, heat pumps and other sector-coupled assets. By providing location- and time-specific flexibility services, FaaS can defer or avoid costly investments in electricity network reinforcement, improve use of existing transmission and distribution infrastructure, reduce renewable energy curtailment, alleviate network congestion and support voltage and frequency management. Furthermore, FaaS can enhance the operational coordination between transmission and distribution system operators, facilitating more efficient procurement and use of flexibility across multiple voltage levels and energy vectors.

As power systems become increasingly electrified, decentralised and digitalised, standardised FaaS frameworks can facilitate the participation of flexible resources in local and national flexibility markets through common communication protocols, transparent market interfaces and robust mechanisms for the verification and settlement of flexibility services. Such frameworks will improve market transparency, increase investor confidence and enable greater scaleability of flexibility solutions across different technologies and geographical regions. These capabilities enhance system reliability, resilience and security of supply, improve the integration of variable renewable energy sources, reduce overall system costs, and support a more efficient and accelerated transition towards a net-zero energy system.

8.4 Outlook and next steps

Three developments will shape the next phase of FaaS deployment and deserve continued attention. The first is regulatory implementation: the national flexibility needs assessments and non-fossil support schemes enabled by Regulation (EU) 2024/1747, together with the EU framework for demand response under development, will determine whether the direction set at European level translates into investable national conditions. The second is operational consolidation: the local flexibility markets and TSO–DSO coordination platforms are moving from pilots to routine operation, and systematic comparison of their designs, including products, baselines, settlement and liquidity, is now possible. The third is cross-vector integration: the coupling of electricity with heat, gas and hydrogen remains the least standardised frontier and the one with the largest untapped long-duration potential.

9. ANNEXES

9.1 Description of generation technologies

Wind power has a certain capacity rating that refers to maximum power at a rather high wind speed. Since wind speeds usually much lower, the so-called capacity factor (annual average production/max capacity) is rather low. This can be misunderstood as wind power only producing power at a low fraction of time, e.g. 30%. In reality there is a fair output up to 70% of the time. If wind power capacity is installed to match normal demand at a normal, average wind speed, then we would see many instances where wind power exceeds demand. That over-production can then be fed into energy storage solutions or e-fuel production, or power supply must be curtailed. Some curtailing must always be accepted to have a reasonable investment in storage systems. It is thus important that all new wind power gets the control functions to enable controllable curtailment.

Wind power is normally supplied to the grid through power electronics converters, As a result, unlike synchronous generators, they can supply only a limited amount of short-circuit current during grid faults.

The ability to supply inertia or fast frequency response to the grid is also limited. Reducing power by curtailing at over-frequency is possible but the increase of power at frequency drop is not possible unless the starting point is in partial curtailment, leaving room for added power supply. If part of the kinetic energy stored in the rotating blades is temporarily released through inverter to provide synthetic inertia, the turbine can inject additional power into the grid immediately after a frequency disturbance. As the rotor slows down, however, it must subsequently regain its nominal speed. During this phase, part of the available aerodynamic power is used to reaccelerate the rotor, causing the electrical power output to temporarily fall below its pre-disturbance level before returning to normal. Reserving some wind turbines in a spinning reserve by partial curtailment or complementing by other power technologies can solve that issue.

Solar PV power was historically installed to optimise energy supply. By a large capacity of PV installed that way, power production peaks at mid-day. Orientating a greater share of panels toward the east and west the production is evened out somewhat, but this is still limited by the number of hours of sunshine. By the combination of solar PV with a typical electricity demand distribution over the day, the famous “duck-curve” for the need of residual load arises. Solar power is also sensitive to cloud formation; a thunderstorm can shade even a large solar field of 100 MW in as little as one minute and when the cloud disappears power supply is drastically ramped up again. Solar power can thus result in residual load overnight, a peak in morning and one in the evening, and it can then also result in less predictable patterns of varied residual load by temporal cloud coverage.

Solar PV supplies power by using power electronics, which means that no capacity for over-current at short circuits can be provided. PV systems typically cause voltage control issues, i.e. there is a need for other resources that can compensate. PV has no stored energy in the system – they do not contribute with inertia or frequency control unless complemented by e.g. battery storage (BESS). However, at large installations curtailing is possible and can be controlled to reduce power supply in over-frequency situations. PV systems are not able to assist in restoring frequency from a too low situation, unless they by intent are operated with a certain curtailment to enable such capacity (not applied today) or by combining with BESS.

Solar CSP (concentrating solar panels) uses a steam turbine for power production; the solar heat collectors are used to produce steam for the turbine operation. Since a rotating machine is used, the system also supplies ancillary services, e.g. short circuit capability up to 5-8 times the generator rating, reactive power and inertia. A power generation system of this type can also be combined with a high temperature energy storage that saves part of collected solar radiation to provide power after sunset and to keep the steam turbine hot through the night and thereby avoid thermal cycle stress of the turbomachinery related to daily cycling.

GT single cycle is ideally for providing backup and peaking power as it is low in capex, has small footprint, starts fast and is capable of running continuously if required. Capacity to ramp power rapidly makes GT suited as a stability anchor for frequency control, creating resilience for large load jumps. Since a synchronous generator is used, short circuit currents up to 10 times nominal rating can be supplied, and voltage control and large inertia are also given.

GTs suffer from the fact that the power capacity decreases when ambient temperature increases. This can be compensated for by lowering the inlet air temperature using either active cooling or by evaporation cooling. It is also possible to temporarily increase GT power by injecting water mist into the inlet air or by temporarily increasing the combustion temperature, even with a penalty to machine component life. Many GTs are limited in part load to stay compliant with emission limits. This minimum load can often be decreased temporarily by inlet air heating. Inlet air heating at part load also improves efficiency, especially if low temperature waste heat is recovered for the heating. GTs are able to run on various types of fuel – they often have dual fuel capability, e.g. operating on natural gas with diesel oil as back-up. Natural gas can easily be substituted by biogas, but other gases can also be used with development for hydrogen combustion being well advanced. Examples of other suitable future fuels are ammonia, bio-methanol, e-methanol, ethanol, HVO (hydrogenated vegetable oil). With the installation of a clutch, the generator can remain spinning, synchronised with the grid, also when the GT is stopped. This enables support to the grid with ancillary services also when the GT is not being operated.

The most urgent need for grid ancillary services is in situations where renewable wind and solar dominate the supply. In such situations a GT can operate at zero load by combustion of hydrogen produced at the same time from grid electricity. The GT is then in frequency control mode, provides all required ancillary services and is ready as dispatch active power in an instant since it is already hot and operating. This operating mode is called **“green idling”.** Emissions during green idling can be kept low because there is no carbon present. When the machine leaves the green idling mode to dispatch active power, fuel may be switched, e.g. to biogas and the hydrogen production can reduce or stop taking grid power. Further details at Green idling: a zero-carbon way of stabilising the grid - Modern Power Systems

GTCC, GT in combined cycle configuration: When a GT is expected to operate many hours per start and for many hours per year, the available waste heat in the GT exhaust is use in a heat recovery steam generator (HRSG) to supply steam to a steam turbine. For large GTs, and when baseload is planned, an advanced steam cycle is used, including several pressure levels and even with steam reheat. For smaller plants the steam cycle is made simpler. Start time from cold condition for an advanced steam cycle may be more than 3 hours whilst a steam cycle that uses single pressure and low steam conditions may possibly start from cold to full load in under 30 minutes. The lower investment cost of a less advanced steam cycle design makes it also a more economic choice for a cycling plant that has fewer operating hours to pay back investment.

GTCC plants are equipped with bypass stacks in cases where independent operation of the GT from the bottoming cycle is desired, e.g. for operation of the GT as a backup resource when the bottoming cycle is being serviced or in preservation. It is often believed that a bypass stack is also needed to allow unhindered fast start of the GT. However, for an internally insulated HRSG, unhindered fast GT start is possible if a purge credit system is installed and the pressure parts are kept warm (about 150 °C) at standstill.

The steam exiting the steam turbine must be cooled and condensed back to water. An air cooled condenser makes the plant independent of water supply except for a small make-up to the steam cycle losses. However, a water-cooled condenser or a wet cooling tower is better for plant efficiency. Instead of rejecting the waste heat to the ambient, it may be recovered for industrial or domestic heating, as stated in CHP section below.
Duct burners placed in the exhaust duct between the GT and the downstream HRSG is a cheap, efficient power peaker which also is very fast to activate (few minutes). When the burners operate, they use excess oxygen present in the exhaust gas and only add fuel, with more steam being produced from the HRSG to be expanded

in the ST.

Reciprocating engines can be either gas engines, diesel engines or dual fuel engines. While diesel engines are typically used for islands and remote areas with no gas fuel supply and back-up/emergency solution, gas engines are widely used when gas fuel is available. Gas engines are a preferred solution for distributed power and commonly used for CHP. They achieve high single cycle electrical efficiency up to 50%, and when used as CHP the total efficiency can be 90% and more. Diesel engines used for providing back-up or emergency power can start very quickly, within less than 30 seconds to full load; modern gas engines typically start in 3 to 5 minutes from standstill to full load. Special gas engine solutions are available for use as back-up solution to grid power and can start in under 1 minute from standstill to full load. The combination of high single cycle efficiency of >45% and fast start capability makes gas engines an ideal solution for grid balancing and providing residual load.

When gas engines are used as CHP, the waste heat is collected from the motor block cooling and exhaust heat. Hot water temperatures of typically up to 110°C can be achieved, which makes this a very good solution for providing district heating. Gas engines operate with a flat rated power over a wide ambient temperature range, typically up to 35 – 40°C. Power plants based on gas engines are typically built as a multi-unit configuration, achieving high redundancy and operating flexibility. While an individual unit can run on part load down to about 40% load, a multi-unit power plant has a lot more part-load flexibility with shutting down units not needed and run the remaining at full load and maximum efficiency. Furthermore, gas engines run on a very wide range of gaseous fuels from low BTU gases such as coal mine gas or blast furnace gas to hydrogen. Gas engines have been used widely for converting raw biogas (including sewage gas and syngas) to power. Already today gas engines can run on 100% hydrogen and 100% ammonia operation has been demonstrated.

Gas engines produce electricity with a synchronous generator. They can therefore provide inertia and almost all the ancillary services that an electricity grid needs today (see table below). When gas engine gensets are installed with a clutch, the engine can be shut down and the generator can operate as a synchronous condenser. The fast startup time of gas engines allows for the support of a wide range of ancillary services including frequency restoration reserve.

CHP (Combined Heat and Power) plants are sadly, due to historical reasons, considered as inflexible by many, with the only exception for when part of the plant can act as a power-only plant, e.g. by use of a cold condenser. It must though be remembered that CHP is not a technology in itself – it only stands for the fact that waste heat from a power plant is being captured for use. Used power technology for the CHP application can thus be as flexible as in any other power-only plants.

The supply of heat has in many cases been the priority for deciding CHP plant load, and electric output is then just a side product from that operation. The plant is then in a heat load following mode, often named “must run obligation”.
However, this can be avoided by using tools that create flexibility. In general, any CHP plant can operate flexibly for electric dispatch if it can interplay with another dispatchable heat source, e.g. a heat only boiler, duct burners behind a GT or with high temperature heat storage. Then general load on the CHP can be modulated to supply desired electric output, and changed CHP heat output is then compensated for by the other heat supply. Buffering of heat at the demand side is another approach that also creates flexibility in CHP load, e.g. by a large-capacity hot water tank for district heat distribution or by steam accumulator for industrial steam supply. Plants using a steam turbine can let part or all steam bypass the turbine when electricity production is not desired in order to minimise fuel usage. Part steam bypass can also be used to enable some frequency stabilisation service.

For most CHPs typical marginal efficiency of electric output is about 90% (electric output / marginal addition of fuel above needed for heat only supply). This marginal efficiency is also valid when heat supply is just delayed by filling a heat storage device as long as the heat losses from the storage system are small. The high marginal efficiency means that CHPs should have priority over power-only generation. The heat demand can be seen as an asset since it creates added income / value beside the power supply.

For district heating, by the use of heat storage to buffer up heat during operation for later distribution, a CHP plant can be sized significantly larger in heat output than the serviced district heat demand and have the load control focused to electricity dispatch. In such cases, the CHP needs to stop operation or reduce load when the storage has become full. However, since hot water storage is low in cost compared to other types of storage, a duration up to few days at full load may be reasonable when using overground storage tanks. Longer duration, up to number of months scale, characterizes underground cavern storage or pit storage. Oversizing a CHP compared to the continuous heat demand will not lead to loss of efficiency or lost qualification as “high efficiency CHP” as long as the plant is suited to cycling operation and the heat output over a longer period does not exceed the average heat demand. The purpose of oversizing the CHP plant is to provide more residual load to the electric system. In an energy system where residual load is requested in periods/cycles, an oversizing of flexible CHP plants combined with storage is thus an efficient way to balance variable renewable power.

In industrial applications, the use of a steam accumulator between the steam turbine extraction and the steam users can enable frequency response over time frames up to 10-minute. It can also be used for damping steam supply variations if e.g. switching between CHP and electrified solutions is applied.

Many existing CHP plants are in fact hybrids of the CHP principle and power-only principle. They can thus reject heat to ambient air (or water) to enable full load operation also when the heat load is low. This can be made either by rejecting heat directly from the steam turbine by use of a cold condenser, or, when a backpressure turbine is used, by use of a cooler that rejects heat indirectly via the heat distribution system, often called a “summer cooler”. Such plants can be very flexible, but the flexible load is from power-only share. A plant with cold condenser also suffers from constant heat loss in situations where power-only share is not desired.

Replacement of conventional boiler-based CHPs (e.g. coal fired) by modern flexible CHP significantly improves electric efficiency. Since the total efficiency (electricity + heat) is about the same, the share of heat output is reduced when electricity is increased and this means that the ratio of electricity to heat output is increased by up to 200%, i.e. 3 times as large electric output as the original plant when heat output is the same. The main positive effect of coal to gas shift in CHP applications is that a large new flexible residual load capacity is created at far better efficiency than from separate power-only plants.

CHP plants can start as fast as open cycle can, but some measures for pre-purge of downstream WHRU / HRSG are required.

Hydro power

Hydropower can either use a flow of water, such as a river, that is not allowed to be modulated or be highly dispatchable, if a water reservoir is used. Some hydropower plants also have the ability to partly act as pumped storage by pumping water back to the upper reservoir; however, this requires a lower reservoir to be also available. When the output of a hydropower turbine is increased or decreased, the water flowing through the penstock must accelerate of decelerate accordingly. However, the rate at which the flow can be changed is limited by the risk of inducing water hammer pressure transient in the hydraulic system. Typical time from zero to full load is about 5 minutes. There are, however, hydro turbines well suited for strong frequency response and even grid forming duty. Some hydropower plants have very large water reservoirs, which makes seasonal storage possible.

Hydropower will shift role from a base load power provider to flexible load that complements wind and solar. The reduced power supply in periods of high wind and solar production results in savings of water taken out from the reservoir, allowing higher power capacity to be delivered later when it is requested. Upgrade of power capacity in existing hydropower plants therefore presents an opportunity. However, increased capacity results in larger water flow further downstream, and periods of very low power results in a trickle flow. Environmental concerns may, however, lead to water permits being updated towards reduced maximum flowrate and increased minimum flow rate, i.e. decreased load range for the hydropower plant. Concerns for fish in rivers also have resulted in the closure of some small hydro plants.

Geothermal power

Geothermal plants for power production require high temperatures from the well and therefore are easiest to construct in regions with volcanic activity like Iceland and California. There are, however, regions in continental Europe that are being investigated for geothermal power, using deep wells. Geothermal power has very low running costs and therefore usually provides baseload. More flexible operation is possible mainly by using steam turbine bypass. The steam production from the well can be modulated somewhat but it is often not advisable to reduce production to ensure well stability. When using a steam turbine bypass, power is in effect curtailed but the response rate of the steam turbine is then rather fast, at least for a part of the load regime, often about 15 % per minute. Minimum load for continued steam turbine operation can be down to 10%. If load changes are limited to within 10% range and are made at fairly high-power level, it may be possible to handle as an instant load step.

An alternative, lower cost type of geothermal energy is for direct use for domestic or industrial heating without any power generation. Such applications do not require such high temperature levels of the geothermal source as for power generation. Even geothermal heat at low temperatures requiring heat pumps for a lift to useful temperature may contribute significantly to decarbonisation of the heating sector.

Conventional power plants (gas, coal, biomass)

Conventional plants that fire fixed fuel like coal and biomass require about a day or even longer to start, and they are mostly not technically suited to frequent starts and stops either. The high investment cost also makes them best suited for baseload operation. They can, however, modulate power at limited ramp rates and typically have a minimum operating load at about 25%. When operated in fixed pressure mode, a conventional boiler partly functions as energy storage. If the steam turbine makes a fast load change the energy buffered in the water and steam in the boiler can temporarily result in a higher/lower steam flow rate than the steady state balance. The fuel supply is adapted to the new load situation and the lag time from fuel supply to changed steam production only results in pressure variation in the boiler. The output change from the steam turbine is ruled by the ST control. Typically, these plants can provide strong frequency response in a load window of about 5-10% of their rated capacity. Larger load variations, however, must be implemented more gradually, with ramp rates typically limited to around 5% of rated power per minute.
If such plant is equipped with post-capture of carbon dioxide, then the very high added investment makes it even more targeted to baseload operation to limit the capital cost distributed per generated energy. Post-cap equipment is not suited to flexible operation either. However, flexibility can be created through bypass of the steam turbine, but then power is partly curtailed similar to the situation for geothermal, but with part of fuel consumption being wasted.

Gas fired boilers are more capable to start and stop; they can achieve somewhat faster load gradients and are lower in investment cost.
The table below is intended as a qualitative orientation tool rather than an exhaustive technical specification. Generation technologies are stand-alone technologies; no hybrids are considered. It should be read across rows and columns: rows refer to flexibility features or technology capabilities, while the columns indicate the most important generation technologies. The symbols used in the technology comparison table provide a relative assessment only: “++” indicates a very strong fit, “+” a strong fit, “0” an average or context-dependent fit, “-” a weak fit, and “--” a very weak or non-applicable fit. These ratings are indicative and may vary depending on plant design, operating strategy, grid location, fuel availability, market rules, and contractual arrangements. More information about ancillary services can be found in the ETIP-SNET Paper Grid Security.

Features / Capabilities Generation technologies	Wind (onshore / offshore)	Solar PV (+inverter)	Solar CSP	SCGT, power only (incl. CHP)	CCGT, power only (incl. CHP)	Reciprocating engines (cascaded) (incl. CHP)	Hydro power dispatchable (using a dam, cascaded)	Hydropower continuous (using running water)	Geothermal Plants	Conventional power plants (coal, biomass)	Nuclear Power Plants	Fuel Cells Power Plants
Synchronous inertia response	--	--	++	++	++	++	++	++	++	++	++	--
Virtual inertia response	+	0	--	--	--	--	--	--	--	--	--	0
Primary frequency control / response FCR (frequency containment reserve)	0	0	++	+	+	+	++	++	++	++	++	0
Fast frequency response / reserve (FFR)	0	+	--	--	--	--	--	--	--	--	--	+
Secondary frequency control / regulation aFRR (automatic frequency restoration reserve)	--	--	++	++	++	++	++	++	++	++	++	+
Secondary frequency control / regulation mFRR (manual frequency restoration reserve)	--	--	++	++	++	++	++	+	++	++	++	+
Tertiary frequency control RR (replacement reserve)	--	--	++	++	++	++	++	+	++	++	++	+
Voltage control: steady state reactive response	++	++	++	++	++	++	++	++	++	++	++	++
Voltage control: dynamic reactive response	++	++	++	++	++	++	++	++	++	++	++	++
Voltage fast post-fault active power recovery	++	++	++	++	++	++	++	++	++	++	++	++
Rocof (Rate of Change of Frequency)	+	+	+	+	+	++	++	++	+	+	+	+
Short circuit current	--	--	++	++	++	++	++	++	++	++	++	--
Fault Ride Through 200ms	++	++	++	++	++	++	++	++	++	++	++	+

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