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Optimizing Ancillary Services provision by Distributed Energy Resources towards 100% Renewable Electric Power Systems

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Abstract

The rapid decarbonization of European power systems is driving a structural shift from synchronous generators to non-synchronous, inverter-based Distributed Energy Resources (DERs). This transition erodes traditional sources of ancillary services (ASs)—such as inertia and frequency control—while creating opportunities for resources like PV, BESS, EVs, and flexible loads to assume these roles. The challenge is aligning market design and control strategies to harness DER capabilities in systems targeting 100% renewable penetration. This thesis develops an integrated framework for optimizing AS provision by DERs. First, it synthesizes European electricity market design, detailing the 2019–2024 reforms, SDAC, SIDC, and balancing platforms (PICASSO, MARI). Second, it proposes a technology-neutral AS taxonomy, extending conventional services to include synthetic inertia, fast frequency response, and dynamic reactive response, systematically mapping them to emerging providers. Third, it critically reviews ~60 recent studies on DER optimization and control. Crucially, the thesis identifies systemic gaps in current literature: the overestimation of DER flexibility due to ignored grid constraints, a "validation paradox" relying on synthetic test systems, overstated battery economics ignoring non-linear degradation, and the under-utilization of green hydrogen as a foundational flexibility pillar. To address these, the thesis proposes actionable design principles, including a "Deliverable Flexibility Index," network-aware AS procurement, and tripartite TSO-DSO-Aggregator contracts. By bridging technical, regulatory, and market perspectives, this work provides a unified roadmap to exploit distributed flexibility while maintaining grid security in fully renewable power systems.

Key-words: Ancillary services; flexibility; market design; electricity markets; distributed energy resources; optimization

Abstract in italiano

La rapida decarbonizzazione dei sistemi elettrici europei sta guidando una transizione strutturale dai generatori sincroni alle Risorse Energetiche Distribuite (DER) non sincrone basate su inverter. Questa transizione riduce le fonti tradizionali di servizi ancillari (AS)—come l'inerzia e il controllo di frequenza—creando al contempo opportunità affinché risorse come FV, BESS, veicoli elettrici e carichi flessibili assumano questi ruoli. La sfida è allineare il design dei mercati e le strategie di controllo per sfruttare le capacità dei DER in sistemi orientati al 100% di penetrazione rinnovabile. Questa tesi sviluppa un quadro integrato per ottimizzare la fornitura di AS da parte dei DER. In primo luogo, sintetizza il design dei mercati elettrici europei, dettagliando le riforme 2019-2024 e le piattaforme di bilanciamento (PICASSO, MARI). In secondo luogo, propone una tassonomia tecnologicamente neutrale che estende i servizi convenzionali includendo inerzia sintetica e risposta rapida di frequenza, mappandoli sui nuovi fornitori. In terzo luogo, esamina criticamente circa 60 studi recenti sull'ottimizzazione dei DER. Fondamentalmente, la tesi identifica lacune sistemiche nella letteratura attuale: la sovrastima della flessibilità dei DER dovuta all'ignorare i vincoli di rete, un "paradosso di validazione" basato su reti di test sintetiche, un'economia delle batterie sovrastimata che ignora il degrado non lineare, e il sottoutilizzo dell'idrogeno verde. Per affrontare ciò, la tesi propone principi di progettazione attuabili, tra cui un "Indice di Flessibilità Erogabile", un approvvigionamento di AS consapevole della rete e contratti tripartiti TSO-DSO-Aggregatore. Collegando prospettive tecniche, normative e di mercato, questo lavoro fornisce una tabella di marcia unificata per sfruttare la flessibilità distribuita mantenendo la sicurezza della rete.

Parole chiave: Servizi ancillari; flessibilità; design del mercato; mercati elettrici; risorse energetiche distribuite; ottimizzazione

Contents

1 Introduction

Renewable energy sources accounted for 46.9% of net electricity generated in the EU in 2024. Denmark had the highest share of renewables among EU countries in its net electricity generation, with 88.4%, coming mostly from wind, and Italy approached 50%, which is close to the continental average. Wind and solar power accounted for more than 60% of the total electricity generated from renewable sources (39.1% and 22.4%, respectively). Combustible fuels represented around 8.1%, and hydro power was the second contributor to overall electricity production with 29.9%. [1]

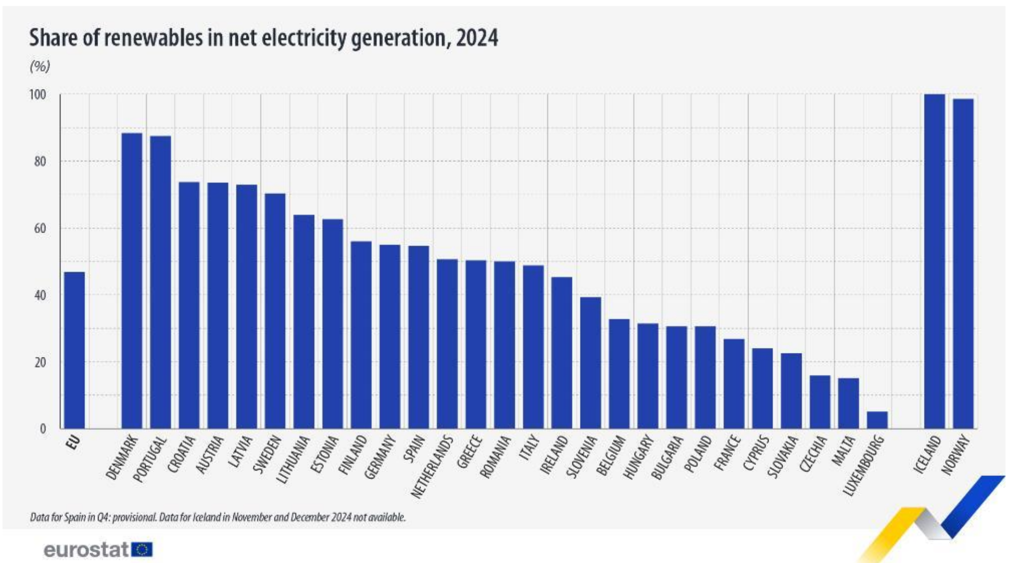

Figure 1 Share of renewables in net electricity generation, 2024 [1]

Renewable sources accounted for 25.4% of all final energy consumed in the European Union in 2024. Solar and wind power, followed by heat pumps, drove this increase in the share of renewables, which is expected to grow further. Meeting the new minimum EU target for renewable sources of 42.5% by 2030 will require doubling the rate of renewables deployment seen over the past decade and a deep transformation of the European energy system [2]. The main sources of renewable energy, like solar and wind power, are intermittent and include a degree of uncertainty in their predicted forecast. Therefore, their percentage is much higher during the day like in the case of solar power, and it also varies with the season. This means that its share of electricity production can approach 100% or sometimes even higher during certain periods when we have higher solar irradiation and high wind speeds at the same time. Furthermore, as we move closer towards higher percentage of renewable energy penetration, it is inevitable that over 100% must exist during the day for PV panels and it is necessary to find a way to store this energy to cover part of the night hours demand. Most of the current national electric grid systems lack significant energy storage systems and there is an almost instantaneous match between electricity production and demand. Electric grids traditionally rely on synchronous generators (SGs) for the stability of the grid due to their wide range of capabilities. The movement towards less SGs and more non-dispatchable inverter-based resources (IBRs) through the distribution system tend to decentralize the generation and cause severe issues regarding flexibility and control of the grid. This leads to load profile with steeper ramps and deeper valleys and requires the dispatch of flexible resources. Variable renewable energy (VRE) replaces SGs, and its inability to provide an inertial response reduces system inertia levels and shortens the response time to disturbances. Thus, fast-acting reserves must be dispatched to arrest the frequency drop following a disturbance and restore the grid balance or at least give more time to slower-acting governor response systems to interact given its decreasing share of the electricity contribution. Distributed energy resources (DERs) are one of the promising solutions to provide Ancillary services (ASs) which are crucial to help Transmission System Operators (TSOs) in frequency response, voltage control, and system restoration to ensure system stability and flexibility [3].

1.1 Research context

The rapid decarbonization of power systems is driving a structural shift from large synchronous generators towards converter-interfaced, DERs such as photovoltaic (PV) plants, wind generation, battery energy storage systems (BESS), electric vehicles (EVs) and flexible demand. In Europe, renewables already provide nearly half of net electricity generation, and their share continues to rise under increasingly ambitious 2030 and 2050 targets, implying operating conditions where non-synchronous generation can dominate instantaneous production. This transformation erodes traditional sources of ASs —inertial response, primary and secondary frequency control, voltage support and system restoration—that have historically been supplied as an inherent by-product of synchronous generation.

At the same time, advances in power electronics, smart inverters, energy storage and digital control have enabled DERs to provide many of these services explicitly, including virtual or synthetic inertia, fast frequency response, ramp-rate control, volt-VAR support, fault-ride-through and harmonic mitigation. Numerous studies demonstrate how DERs within microgrids, virtual power plants (VPPs) and active distribution networks can contribute to frequency and voltage stability, either through local control or coordinated dispatch. These technical developments coincide with a broader evolution of electricity-market design, in which markets for frequency containment reserve (FCR), automatic and manual frequency restoration reserves (aFRR, mFRR) and replacement reserves (RR) are increasingly harmonized and opened to new resources, while distribution system operators (DSOs) are expected to orchestrate flexibility at lower voltage levels.

Within the European Union, the 2019–2024 legislative package and the recent electricity-market-design reform have reinforced this direction by formalizing balancing platforms such as FCR Cooperation, PICASSO and MARI, shortening market time units to 15 minutes, and explicitly promoting consumer and DER participation in energy and AS markets. At the same time, pilot projects in several Member States—including smart-inverter programs, DSO-level reactive-power schemes and aggregator-based balancing pilots such as the Italian UVAM—show both the technical feasibility and the regulatory complexity of integrating distributed flexibility into AS procurement. Against this backdrop, there is a clear need for a system-level, technology-neutral perspective that connects detailed technical capabilities of DERs with evolving European market structures and the requirements of future power systems operating with very high, potentially 100%, shares of renewable generation.

1.2. Aim of the work and similar works

The aim of this work is to develop an integrated framework for optimizing ancillary-service provision by DERs in future electric power systems that operate with very high or even 100% renewable penetration. Concretely, the thesis pursues three main objectives:

(i) to provide a structured and up-to-date overview of European electricity-market design, with emphasis on balancing and ancillary-service products and their recent reforms.

(ii) to construct a comprehensive, technology-neutral taxonomy of existing and emerging ASs, mapping them to the capabilities of synchronous and non-synchronous resources, including DERs; and

(iii) to synthesize and critically assess optimization and control approaches in the literature for DER-based ASs in microgrids, active distribution networks and bulk power systems, identifying gaps and design principles relevant for the transition towards fully renewable power systems.

A substantial body of related work already addresses elements of this problem from different angles. Several review papers and concept studies focus on defining new ASs that can be provided by converter-interfaced distributed renewable energy sources (DRES), and on proposing metrics and measurement procedures for services such as virtual inertia, primary frequency response, ramp-rate limitation, reactive-power voltage support, fault-ride-through and harmonic mitigation at the distribution level. Other works survey the role of energy storage in microgrids, highlighting how BESS can deliver frequency regulation, voltage control and power-quality services in conjunction with renewable generation. Smart-inverter-oriented reviews emphasize reactive-power and voltage-support capabilities from PV and EV inverters, as well as their potential use as STATCOM-like devices for local ASs. Parallel strands of literature examine fast demand response as a source of ASs, aggregation and control of customer-owned

DERs and prosumers, and techno-economic assessments of specific flexibility providers such as EVs in vehicle-to-grid schemes.

Beyond reviews, there are also technically detailed contributions that design control strategies and optimization models for microgrids, virtual power plants and active distribution networks. These include hierarchical congestion-management and dispatch schemes that call upon DERs and microgrids for ASs, as well as dynamic models of DER-based frequency control for specific systems such as the Australian National Electricity Market or test systems in stability studies. Finally, market-oriented analyses survey existing ancillary-service markets, discuss competition and procurement mechanisms, and highlight the implications of rising distributed generation for AS demand and market power. However, these works typically focus on one subset of technologies (e.g. storage, smart inverters), one system scale (microgrid or distribution), or one family of services (frequency or voltage), and most pre-date the most recent wave of European market-design reforms.

Against this background, the specific role of this thesis is to bridge detailed technical, regulatory and market perspectives by offering a unified view of ASs and DER participation that spans from microgrid-level control to the pan-European balancing architecture, and explicitly targets operating conditions compatible with 100% renewable electric power systems.

1.3. Research novelty

Relative to the existing literature, the main novelty of this thesis lies in the combination of scope, timing and perspective. First, it provides a comprehensive and up-to-date synthesis of European electricity-market design for energy and ASs, including the current structure of day-ahead and intraday coupling (SDAC, SIDC), balancing platforms (FCR Cooperation, PICASSO, MARI, and the phase-out of TERRE), and the 2019–2024 market-design reform with its emphasis on 15-minute products, long-term contracting (PPAs and two-way contracts-for-difference) and enhanced ACER/REMIT oversight. While prior reviews discuss ancillary-service markets, they generally do so at a higher level or in a pre-reform context and do not connect the detailed European institutional framework to the technical requirements of a 100% renewable system.

Second, the thesis develops a technology-neutral ancillary-service taxonomy that goes beyond the conventional frequency- and voltage-related services to include new or emerging products such as synchronous inertial response (SIR), virtual or synthetic inertia, fast frequency response (FFR), fast post-fault active-power response (FPFAPR), fast ramping and ramp-rate control, grid-forming services, and various flavors of demand-side and sector-coupled flexibility. This taxonomy is accompanied by detailed provider–service mapping that systematically links synchronous generators, inverter-based renewable plants, storage systems, EV fleets, data centers, HVDC links and aggregated prosumer portfolios to the services they can technically provide under appropriate control strategies, in contrast to existing reviews that typically treat only one or two resource classes in isolation.

Third, the work explicitly integrates system-level flexibility concepts—such as sector coupling (power-to-heat, power-to-hydrogen), vehicle-to-grid, and data-center flexibility—into the ancillary-service discussion and situates them within current and prospective European market architectures. This leads to a set of design principles and qualitative optimization guidelines for how future ancillary-service products and procurement schemes should be structured to exploit distributed flexibility while maintaining system security in the absence of large synchronous fleets. In doing so, the thesis complements technically focused works on microgrid control and active-distribution-network optimization by providing a higher-level, market-compatible framework tailored to the conditions of very high and 100% renewable penetration, which is largely absent from the existing literature.

2 Ancillary Services

In the literature (including EU regulation), there is a variety of definitions, classifications and terminology used regarding ancillary services (ASs) in EU power systems. ASs can be defined as those services that ensure secure power system operations and help the system operators achieve this fundamental duty, since the mere act of the procurement of electrical energy and capacity does not guarantee system security. Thus, system operators must acquire a set of ASs from capable providers. In EU Directive 2019/944, Art. 2 (48), an 'ancillary service' refers to "*a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management*". In addition, in Art. 2 (49), a 'non-frequency ancillary service' refers to "*a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability*"

2.1. Electricity market design in Europe (wholesale energy markets + ancillary services markets)

In Europe, system operators are known as transmission system operators (TSOs), and unlike the US, are allowed to own transmission assets. Most of them belong to the classification of natural monopoly and are regulated by national independent agencies like TERNA in Italy. They typically hold high voltage lines and some medium and low voltage transmission lines across the country and are also coupled with other European countries by cross-border lines that make European market coupled and integrated.

2.1.1. European Electricity Market Design Overview

The EU electricity market aims at incentivizing the clean energy transition and delivering energy security. It helps ensure affordability by boosting competition, improving the long-term markets and allowing consumers to choose energy suppliers. The European electricity market is the largest integrated electricity market in the world with 11.3 million km of electricity lines and cables across the EU alone, enough to encircle the Earth 282 times, bring electricity to 266 million customers. It is structured as an integrated internal energy market designed to support the clean energy transition, reinforce energy security, and ensure affordable prices through competition and cross-border cooperation. The system currently saves Europeans €34 billion annually, with potential savings reaching €40-43 billion by 2030 through deeper integration. Day ahead and intraday market coupling is a sophisticated approach that connects multiple electricity markets across geographical regions via the cooperation of power exchanges and transmission system operators to create a single, larger, integrated and more liquid marketplace. It allows electricity to flow seamlessly across borders, facilitating efficient resource allocation, fostering competition, reducing price discrepancies, and enhancing grid stability and energy security.

2.1.2. Day-Ahead Market (SDAC - Single Day-Ahead Coupling)

The EU transitioned from hourly to 15-minute market time unit as trading intervals (Now 96 intervals per day instead of 24 hourly) on September 30, 2025, for delivery starting October 1, 2025 as envisaged in the Electricity Regulation (EU/2019/943). [4] This transition creates more precise price formation reflecting renewable generation patterns, better integration of variable renewables (solar and wind), improved ability to capture short-term production fluctuations of PV and wind, and enhanced flexibility and grid reliability. All European bidding zones are coupled through the EUPHEMIA algorithm (EU Pan-European Hybrid Electricity Market Integration Algorithm) and produce uniform marginal pricing within each bidding zone and typically close around 12:00 noon the day before delivery.

2.1.3. Intraday Markets (SIDC - Single Intraday Coupling)

Intraday Markets allow market participants to adjust positions closer to real-time after day-ahead market closure through continuous trading on the XBID platform (cross-border intraday market). The gate closure recently moved from 1 hour to 30 minutes before real-time (cross-zonal gate closure) and they also operate at 15-minute intervals.

2.1.4. Forward Markets and Long-Term Contracts

To decouple consumer prices from short-term fossil fuel price volatility and provide stable revenue streams for renewable energy investments, the 2023-2024 electricity market design reform emphasized:

Power Purchase Agreements (PPAs): Long-term contracts between generators and consumers

Contracts for Difference (CfDs): Two-way contracts providing price stability

2.1.5. Reform of the electricity market design

To boost renewables, better protect consumers and enhance industrial competitiveness, the Commission proposed a reform of the existing electricity market rules in March 2023, as part of the Green Deal Industrial Plan. The new electricity market design rules entered into force on 16 July 2024: the amending Directive EU/2024/1711 and the amending Regulation EU/2024/1747 [5] [6] . To support the implementation of the electricity market design reform, as well as the revised Renewable Energy Directive and the Affordable Energy Action Plan, the Commission published, on 2 July 2025, a recommendation and 3 guidance documents for EU countries.

Reform objectives

The revised rules aim to make the EU energy market more resilient and the energy bills of European consumers and companies more independent from the short-term market price of electricity. This can be achieved by using long-term contracts, such as power purchase agreements and structuring investment support with 2-way contracts for difference. The reform will also help accelerate the deployment and integration of more renewable energy sources in the energy system, and enhance protection against market manipulation, promoting the stability and predictability of energy prices and thereby contributing to the competitiveness of EU industry.

This will be achieved by introducing a new enforcement regime with an enhanced role for the Agency for the Cooperation of Energy Regulators (ACER) in cross-border investigations, allowing it to pursue important cross-border cases with the most significant impact on the markets. The reform will also enhance the supervision of reporting parties and data sharing between relevant authorities, increase market transparency through a liquified natural gas (LNG) price assessment and benchmark and ensure more effective enforcement towards non-EU companies, who will have to designate a representative in the EU.

The new rules amend the following pieces of EU legislation:

1- Electricity Directive and Electricity Regulation

The Directive on common rules for the internal market for electricity (EU/2019/944) and the Regulation on the internal market for electricity (EU/2019/943) put the consumer at the center of the clean energy transition, enabling active participation, with a strong framework for consumer protection. The rules allow more flexibility to accommodate the increasing share of renewable energy in the grid and contribute to the creation of green jobs and growth.

2- The ACER Regulation

Regulation (EC/713/2009) established the Agency for the Cooperation of Energy Regulators (ACER), and it was recast with Regulation (EU) 2019/942 as part of the Clean energy for all Europeans package. ACER acts as an independent body to foster the integration and completion of the European internal energy market for electricity and natural gas. The agency's tasks include, among others, the coordination of actions of national energy regulators at European level (including taking binding decisions in case national regulators cannot agree), the development of common network and market rules, the participation in regional and cross-regional initiatives, the monitoring of market activities (including supervision to combat market manipulation to the detriment of other market participants and consumers), or advice to the EU Institutions on trans-European energy infrastructure development or security of supply.

3- REMIT Regulation

The Wholesale Energy Market Integrity and Transparency (REMIT) Regulation (EU/1227/2011) ensures that consumers and other market participants can have confidence in the integrity of electricity and natural gas markets, that prices are fair and competitive based on supply and demand, and that no profits can be drawn from market abuse. [7]

4- Revised Renewable Energy Directive

The more flexible the energy system is, with generation that can rapidly turn on or off, storage that can absorb or put power onto the system, and responsive consumers who can increase or decrease their demand for power, the more stable prices can be and the more renewable energy the system can integrate. The Renewable Energy Directive (EU/2018/2001) was already amended by Directive (EU/2023/2413) which entered into force on 20 November 2023.

The Regulation on risk preparedness in the electricity sector (EU/2019/941) is also part of the EU electricity market design but is not concerned by the reform. It requires EU countries to prepare plans for potential future electricity crises, putting the appropriate tools in place to prevent, prepare for and manage these situations. It also requires that EU countries - using common methods - identify all possible electricity crisis scenarios at national and regional levels and prepare risk preparedness plans based on these scenarios. Above all, this preparation requires EU countries to cooperate and coordinate in a spirit of solidarity. It also establishes a framework for more systematic monitoring of security of supply issues via the Electricity Coordination Group. [8]

2.1.6. Energy pricing models

As in other sectors, the EU electricity market includes a number of different players in the supply chain – from producers to suppliers, to end-consumers - with wholesale prices at one end of the supply chain and end-user prices at the other.

The wholesale market in the EU is a system of marginal pricing, also known as **a pay-as-clear** market, where all electricity generators get the same price for the power they are selling at a given moment. Electricity producers (from national utilities to individuals who generate their own renewable energy and sell into the grid) bid into the market: they establish their price according to their production cost. Renewable energy sources are produced at zero cost and are therefore by definition always the cheapest. The bidding goes from the cheapest to the most expensive energy source. The cheapest electricity is bought first, next offers in line follow. Once the full demand is satisfied, everybody obtains the price of the last producer from which electricity was bought.

This model provides efficiency, transparency and incentives to keep costs as low as possible. There is consensus that the marginal model is the most efficient for liberalized electricity markets. In fact, it was used by most EU countries before being anchored in EU legislation.

The alternative would not provide cheaper prices. In the **pay-as-bid model**, producers (including cheap renewables) would simply bid at the price they expect the market to clear, not at zero or at their generation costs. Overall, it is better for consumers to have a transparent model that reveals the true costs of energy and provides incentives for individuals to become active in generating their own electricity.

2.1.7. Ancillary Services Markets

Ancillary services (ASs), also called balancing services, are critical for maintaining grid stability and frequency control. European TSOs procure these services through specialized markets coordinated at the European level.

Standard Balancing Products

According to the **EU Electricity Balancing Guideline (EBGL)**, Europe uses three main categories of balancing reserves:

1. FCR - Frequency Containment Reserve (Primary Control)

FCR Cooperation Platform (operational since 2017)

- **Participating TSOs:** The cooperation currently includes 12 TSOs from 9 countries, specifically: Austria (APG), Belgium (Elia), Switzerland (Swissgrid), Germany (50Hertz, Amprion, TenneT DE, TransnetBW - 4 TSOs), Western Denmark (Energinet), France (RTE), Netherlands (TenneT NL), Slovenia (ELES), and Czechia (ČEPS).
- **FCR Procurement Outside the Cooperation:** TSOs not participating in the FCR Cooperation include major countries and regions such as:
    1. Italy (Terna) - Operates independent FCR procurement
    2. Spain and Portugal (Iberian Peninsula) - Separate procurement mechanisms
    3. Nordic countries (excluding Western Denmark) - Finland, Sweden, Norway, and Eastern Denmark have their own Nordic FCR markets (FCR-N and FCR-D)
    4. Other Balkan and Eastern European TSOs - Including Greece, Romania, Bulgaria, Poland, and others within the continental European synchronous area.

- Even within the FCR Cooperation, each participating TSO must procure at least 30% of its demand locally (known as the "core share"), ensuring that a portion of reserves remains domestically available even in the cooperative framework.
- **Market size:** Largest FCR market in Europe (≈50% of continental European FCR demand). The total FCR requirement for the continental European synchronous area is based on a reference disturbance of ±3,000 MW, distributed proportionally among all TSOs according to their annual feed-in and load.
- **Trading mechanism:** Daily auctions for next-day delivery via TSO-TSO cooperation model
- **Product structure:** Six 4-hour symmetric products per day (implemented June 30, 2020, replacing previous full-day products)
- **Timeline:**
    - Gate Opening: D-7 at 11:00 CET
    - Gate Closure: D-1 at 08:00 CET
- **Benefits:** Larger market access for Balancing Service Providers (BSPs), reduced costs for end users.

2. aFRR - Automatic Frequency Restoration Reserve (Secondary Control)

PICASSO Platform (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation)

- **Optimization platform: LIBRA** (performs economic dispatch)
- **Resolution:** Quarter-hour (15-minute) delivery periods
- **Process:**
    a. Ancillary Service Providers (ASPs) submit tenders to their TSOs
    b. TSOs forward tenders + demand + cross-border capacity to LIBRA
    c. LIBRA determines lowest-cost combination meeting total aFRR requirements through optimization
    d. Results sent back to TSOs for activation
- **Gate Closure:** 25 minutes before real-time
- **Pricing:** Pay-as-cleared (marginal pricing) mechanism
- **Activation:** Automatic with a Full Activation Time (FAT) requirement of 5 minutes (reactive TSO activation strategy in Continental Europe and Nordics)

3. mFRR - Manual Frequency Restoration Reserve (Tertiary Control)

MARI Platform (Manually Activated Reserves Initiative)

- **Formation:** The project started in April 2017 with a Memorandum of Understanding (MoU) signed by 19 TSOs. By 2018, this expanded to a second MoU with 28 TSOs
- **Optimization:** A central platform determines the most cost-effective dispatch of mFRR bids
- **Resolution:** The platform operates on 15-minute periods
- **Process:**
    a. BSPs submit mFRR energy tenders to TSOs
    b. TSOs forward aggregated offers, mFRR demand, and available cross-border capacity to the central platform
    c. Platform calculates the most cost-effective activation (clearing) solution
    d. Results are sent back to TSOs, who then request activation from the selected BSPs
- **Gate Closure:** The standard Balancing Energy Gate Closure Time (BEGCT) for submitting bids to the platform is 25 minutes before real-time (T-25)
- **Pricing:** Pay-as-cleared (marginal pricing) mechanism is used for the settlement of activated energy
- **Activation Types**: MARI supports two activation types: **Scheduled Activation**: Activated at the start of the quarter-hour for the full period, and **Direct Activation**: Can be activated at any point during the 15-minute period for immediate support.
- **Full Activation Time (FAT)**: The standard FAT for mFRR in MARI is 12.5 minutes.
- **Collaboration:** Works with PICASSO and Nordic LIBRA for best practices

4. RR - Replacement Reserve (Restoration Control)

TERRE Platform (Trans European Replacement Reserves Exchange)

- **Technical backbone:** LIBRA platform
- **Resolution:** 15-minute intervals
- **Pricing:** Pay-as-cleared mechanism
- **Gate Closure:** 55 minutes before real-time (allows proactive TSO activation)
- **Purpose:** Restore frequency reserves after activation

- **Integration:** Collaborates with MARI and Nordic LIBRA
- **TERRE Platform Decommissioning**: The TERRE platform (and the LIBRA IT solution for RR) is scheduled to stop operations by December 31, 2025 because the new Electricity Market Design Reform (EMDR) mandates an intraday cross-zonal gate closure time of 30 minutes before real-time (H-30) starting Jan 1, 2026. This timing is incompatible with the existing RR process, which required a 60-minute lead time (H-60) and was too slow to be compatible with this new faster standard. The TERRE project will be officially terminated at the beginning of 2026. TSOs like Terna (Italy) will disconnect earlier (Jan 1, 2025), while others (RTE, Swissgrid, etc.) may continue until the end of 2025. The TERRE project is in its final administrative closure phase, set to fully end by March 2026.

2.2. Conventional Frequency-related ancillary services

Frequency-related ASs maintain the active power balance in normal operation and after a contingency or an imbalance till settlement. The inertial response (IR) is a reserve that is immediately released from synchronous generators after any active power imbalance between generation and demand, thanks to its governor that can automatically change its active power when the frequency value goes outside a predefined deadband during regular or random deviations from the supply and demand and also to its high rotational energy stored. SGs make this control feasible, and if a tight tolerance band is imposed by system operators, these minor imbalances do not trigger what is called primary frequency control (PFC). PFC helps to contain the imbalances in real-time and keep the frequency close to, but not exactly, the nominal frequency. To keep the frequency close to the nominal value, secondary frequency control (SFC) is fundamental to restore scheduled power flows between interconnected areas and reduce the area control error. SFC is a centralized control that can be performed manually or automatically through online generators with automatic generation control (AGC). Online generators with AGC can rapidly modify their active power output in response to rapid imbalances (in the order of seconds to minutes). Manual operation can be performed by system operators for slower fluctuations (intra- and inter-hour). Fig 1.1 shows how the frequency changes after a large under-frequency event and the activation sequence of hierarchical control for a typical large power system. IR helps to dampen the sudden frequency drop and extends the available response time for PFC to act so that system operators avoid disconnection of loads by under-frequency load-shedding schemes. The frequency is held at this slightly deviated value until the power output of another source increases to cover this imbalance. This source is reserved for SFC but using part of the reserve capacity of generators can cause a deficit and TSOs may need to replenish them by rescheduling the generating units. Tertiary frequency control (TFC) restores the power system to pre-contingency status and makes it ready for the next possible imbalance. Three main metrics can be found in fig.1.1. Rate of change of frequency (RoCoF) is a measure of how fast frequency changes and the derivative of frequency to time immediately after the contingency defines the maximum RoCoF. The nadir occurs at the maximum frequency deviation (Δfmax) point, while the maximum allowed frequency deviation (Δfmax ss) sets the quasi-steady-state frequency, that is notionally the frequency reached after inertial and primary response, but before secondary response activation.

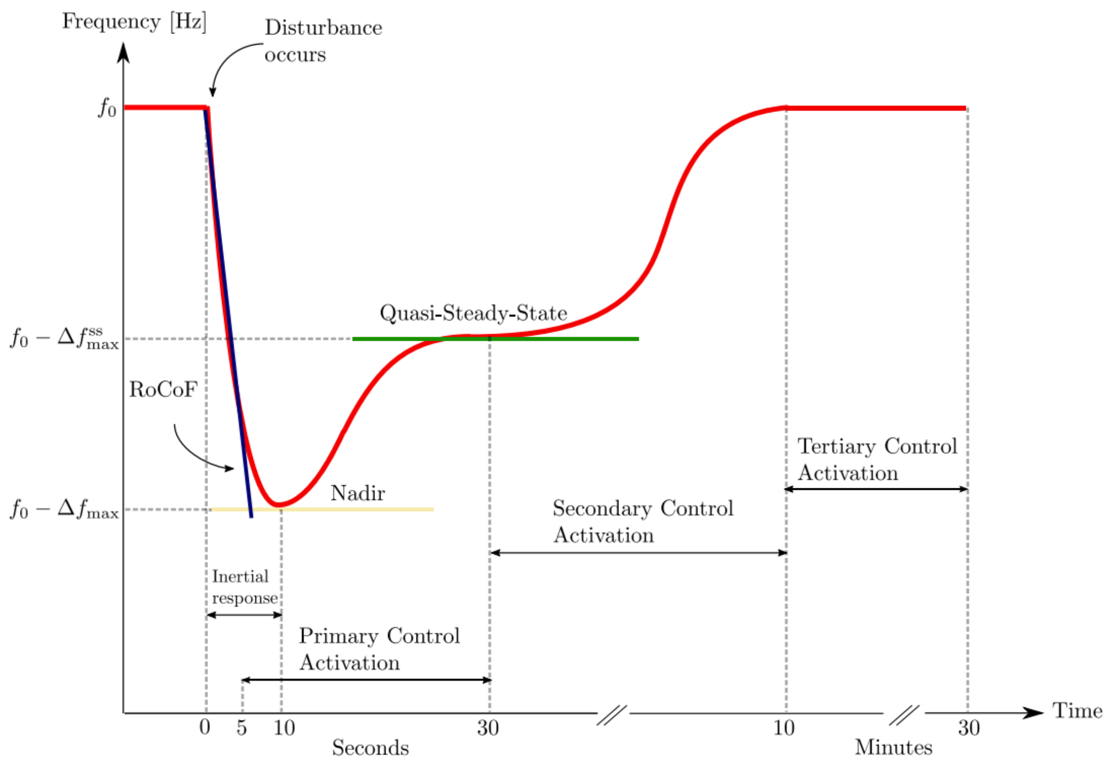

Figure 2: After the inertial response, a hierarchical control brings the frequency back to the nominal value

2.3. Conventional Non-Frequency-related ancillary services

Voltage variations indicate reactive power imbalances, and the supply of reactive power consumes part of the reserved capacity of generation and transmission resources. Voltage control is usually location-constrained since the reactive power losses increases with distance. Therefore, devices are installed at key buses in the power system to provide this AS and prevent excessive reactive power from travelling back and forth through the transmission lines and thus causes losses. Capacitors and reactors are static devices that help to regulate the voltage in steady-state conditions. Dynamic devices have the ability to control the voltage output in response to voltage variations, such as flexible AC transmission system devices. Static devices also include static VAR compensators and static synchronous compensators. In addition, synchronous generators continuously adjust their reactive power to perform Systemic voltage control. Blackout events can cause severe technical and economic losses and thus, power system restoration must be initiated as soon as possible to minimize these losses. This task is usually performed by complex steps that begin with the restart of the generators and appropriate resources rapidly without an external power supply and reactivation of the transmission lines.

2.4. The transition towards 100% Renewable Electric Power Systems

2.4.1 Existing synchronous resources

Available synchronous generators can smooth the transition and allow the gradual introduction of new technologies without facing system instabilities. For example, Ireland/Northern Ireland is imposing a 75% limit for non-synchronous instantaneous generation penetration and a minimum number of online synchronous units to guarantee stable operation. Synchronous condensers can mitigate the reduced system inertia and synchronize torque levels, improving the dynamic voltage support and fault levels provision.

2.4.2. Power electronics and control

Power electronics are essential components in VRE systems to convert and control the power output of their devices and to deploy energy storage systems (ESS). However, the electronic interface decouples variable speed wind turbines (particularly full converter type) and photovoltaic (PV) generators from the grid, preventing the natural transient response under a contingency because they inherently have low or no IR, which leads to lower system inertia if conventional generators are displaced in high instantaneous VRE share conditions. The reduction in system inertia leads to an increase in RoCoF and a lower frequency nadir and this puts pressure on the other generators to respond in a shorter time. Most IBRs connected to the grid are grid-following (GFL) inverters that act as controlled current sources. Their current control loop changes the output current based on the angular reference from the phase-lock loop (PLL) control. The PLL estimates the instantaneous voltage phase angle by measuring the terminal voltage phasor of the inverter. On the other hand, Grid-forming (GFM) inverters operate as voltage sources and an essentially instantaneous response can be achieved. Using some energy buffer and a modified control strategy, such as the so-called virtual synchronous machine, the dynamic behavior of an SG under disturbances can be emulated [9]

2.4.3. Energy storage systems

ESS can smooth power generation from VRE, shift energy and power to enhance system flexibility and provide ASs to the grid. A pumped hydropower storage (PHS) is a versatile technology to provide frequency-related ASs in generating mode. In pumping mode, fixed-speed PHS can operate their SG as a synchronous condenser to increase the inertia of the load. Furthermore, inverter-based variable-speed PHS can contribute to a fast response against frequency deviations after a disturbance. Battery Energy Storage Systems (BESS) can quickly respond to changes in system frequency due to the absence of moving components. BESS are also helpful in enhancing short-term flexibility due to their high ramp capability and can contribute to system restoration if suitably located. Flywheels are well-suited to follow small frequency imbalances, and the short-term storage of supercapacitors can assist in inertia emulation control.

2.4.4. High voltage direct current (HVDC) grids

HVDC transmission lines provide power transfer for long lines, interconnecting systems asynchronously and helping to integrate renewable energy. Line-commutated converter HVDC links have a high-power transfer rating, but their inability to provide an AC voltage from the DC side precludes black start operation. Also, Line-commutated HVDC cannot support voltage control. Voltage source converter HVDC links have black start capability and can contribute to voltage control due to the independent controllability of active and reactive power. Both Line-commutated converter and Voltage source converter HVDC technologies can contribute to frequency response. [3] [10]

2.4.5. Information and communication technology (ICT)

Appropriate ICT infrastructure allows monitoring, controlling, and management of resources at different voltage levels. In distribution systems, households can interconnect sensors and controllers through an internet of things infrastructure network to facilitate the automation of residential appliances and optimize their electricity consumption. Digital meters can enable two-way communication between utilities and consumers, improving the visibility of rooftop PV systems, BESS, and EVs across the grid, allowing consumers to trade their flexibility. [11]

2.4.6. Wind and solar power forecasting models

Forecasting models for renewable energy (like wind and solar) are critical for System Operators (SOs) and market participants due to the unpredictable nature of these sources. These models are categorized into two main types: Deterministic methods provide a single series of expected values and are widely used in power systems by SOs to guarantee sufficient reserve. In electricity markets, the deterministic forecast guides VRE producers to find suitable trading strategies. Significant advantages are simplicity, compatibility with existing operator tools, straightforward evaluation, and fast use and reproduction. Probabilistic methods provide a confidence interval of the expected values, resulting in uncertainty estimation. A range of possible outcomes is an improved solution compared to the deterministic point forecast. Analysis of multiple scenarios potentially optimizes the SO reserve procurement and the decision-making process of VRE suppliers. [12]

2.4.7. Load modeling

Historically, power system analysis has relied on static, passive load models like the ZIP (constant impedance, current, and power) or exponential models. However, these traditional approaches are becoming less effective due to evolving load profiles, specifically the growing use of drive-controlled induction motors in applications like air conditioning and the widespread adoption of DERs. As a result, dynamic load models such as the induction motor (IM) model, which use differential equations, are now essential for analyzing angular and transient stability. Furthermore, composite load models that combine static and dynamic elements (e.g., ZIP plus IM) offer greater accuracy than using either type in isolation. [13]

2.4.8. Demand response

Demand-side participation is one of the most powerful strategies to enhance system stability and flexibility and engage many small and large players, such as industrial, commercial, and residential loads, in AS provision. Three potential strategies are discussed:

2.4.8.1. Sector coupling

Integrating the power sector with heating, gas, hydrogen, and transportation industries unlocks valuable flexible resources for SOs. Technologies such as power-to-heat—encompassing HVAC, refrigeration, and industrial pumping—can utilize inherent energy storage to aid in frequency regulation. Similarly, hydrogen electrolyzers can function as controllable loads, rapidly adjusting production in response to grid frequency changes and demand response incentives. In the transportation sector, Vehicle-to-Grid (V2G) technology enables Electric Vehicles (EVs) to provide rapid bi-directional frequency support. However, successful implementation requires economic structures that compensate EV owners for battery degradation and energy conversion losses caused by frequent cycling. [14] [15]

2.4.8.2. DER aggregation

Distribution-level resources, though geographically dispersed and individually smaller in capacity than transmission-connected assets, represent viable sources for ASs. Aggregators—specialized intermediary entities—coordinate multiple DERs and facilitate interactions among DER operators, SOs, and Distribution System Operators (DSOs). This aggregation model represents a fundamental shift from traditional centralized generation paradigms, enabling consumers to transition into active prosumers capable of supplying services within a decentralized framework. Direct, centralized coordination of individual DERs by SOs through bilateral communication channels is operationally infeasible at scale; aggregators instead serve as interface entities capable of managing thousands of DERs while receiving operational directives from both DSOs and SOs.

2.4.8.3. Data centers

The deployment of digital technologies and cloud-based applications makes the electricity demand very high for large-scale data centers. Global electricity consumption from data centers is estimated to be around 415–450 TWh annually, which represents around 1.4–1.5% of global electricity demand in 2024 and 2025. This consumption is expected to double to nearly 945 TWh by 2030. This is driven by the exponential growth of artificial intelligence and high-performance computing applications. The rapid acceleration of digital transformation and AI adoption makes understanding the interplay between data center operations and grid stability critical. Data centers function as significant and flexible loads within the power system. Data centers are equipped with uninterruptible power supply (UPS) systems that typically utilize redundant BESS to supply backup power in order to ensure uninterrupted service during grid outages. In Addition, many data center workloads, particularly those with lower latency sensitivity, can be temporally shifted to align with periods of abundant renewable generation or favorable electricity pricing signals, and thus enabling demand-side flexibility contributions to grid operations. [16]

2.4.9. New ancillary services

Traditionally, synchronous inertia and PFC have been inherent features of SG operation. In modern power systems dominated by VRE, maintaining sufficient numbers of conventional SGs for stability becomes economically suboptimal. Nevertheless, these units remain operationally essential to sustain minimum system inertia levels and ensure frequency stability. To address this challenge, Synchronous Inertial Response (SIR) has been proposed as an explicit AS, designed to incentivize synchronous generators to operate below their minimum generation thresholds and enable additional units to remain grid-connected solely for their inertial contribution. This service has been adopted in Ireland and Northern Ireland (EirGrid/SONI). Primary Frequency Response (PFR) describes the immediate grid adjustment following frequency deviations. SGs deliver PFR through automatic electromechanical governor controls on their turbines. Alternatively, controlled loads equipped with governor-like functionality can provide equivalent PFR. PFR is well-established in European markets.

As IBRs continue advancing in capability, market frameworks must evolve to recognize technology-neutral solutions and eliminate design barriers that inherently favor traditional synchronous generation. GFM inverters with modified control algorithms and energy storage buffers can emulate synchronous machine dynamics, effectively providing Virtual Inertial Response (VIR).

Additionally, non-synchronous resources can respond instantaneously to rapid frequency changes irrespective of inverter topology. *Fast Frequency Response (FFR)*, a newly introduced AS by several operators, represents an expedited subset of PFR with reaction times exceeding traditional governor response. FFR can be provided through rapid load shedding (via under-frequency relays on large industrial loads) or by mobilizing active power reserves from variable renewables, HVDC systems, or BESS.

VRE sources, including wind and solar generation, inherently exhibit operational variability and forecasting uncertainty attributable to meteorological dependency. Deviations between forecasted and actual VRE generation, coupled with unanticipated net load fluctuations, frequently precipitate substantial active power imbalances and corresponding frequency ramps that challenge grid stability. To deal with these challenges, regulatory frameworks should incentivize existing generation assets to augment their operational flexibility, while simultaneously establishing market-based compensation mechanisms to encourage newly integrated resources to operate in a demand-responsive manner. *Flexible Ramping Capability (FRC)* has emerged as a distinct AS, encompassing the ramping provision from both committed and uncommitted flexible resources capable of rapid power modulation to accommodate forecasted net load trajectories. This AS has been formally adopted and procured by several System Operators.

The progressive displacement of conventional SGs by IBRs diminishes the system's inherent dynamic reactive capability. To compensate for this degradation, EirGrid/SONI has introduced the *Dynamic Reactive Response (DRR)* ancillary service, which provides financial incentives for resources to deliver expedited reactive power adjustments following transient grid events. Complementary to this development, the *Fast Post-Fault Active Power Recovery (FPFAPR)* service has been defined as an emerging AS that compensates wind turbines and other converter-based generators capable of rapidly restoring their active power output following severe voltage depressions, thereby enhancing frequency stability and preventing cascading instability events.

Ancillary Service	Abbreviation	Definition	Providers
Synchronous Inertial Response	SIR	Inherent and uncontrolled response from synchronous resources	SG, Synchronous Condensers, PHS, synchronous loads
Virtual Inertial Response	VIR	Emulation of synchronous inertia from non-synchronous resources responding proportionally to RoCoF	BESS, EVs, supercapacitor, wind or solar headroom, energy stored in HVDC links
Primary Frequency Response	PFR	Active power capability to quickly respond to frequency deviations by increasing generation or reducing demand	SG and controllable loads
Fast Frequency Response	FFR	Faster primary frequency response capability	VRE, BESS, EVs, HVDC links, interruptible loads, data centers
Frequency Regulation	FR	Centralized increase or decrease in active power provided by resources with AGC to continuously match the nominal frequency under normal operation	SG, VRE, BESS, flywheels, controllable loads, DER aggregation
Spinning Reserve	SR	Active power capacity synchronized to the grid, which can be deployed immediately under a contingency condition	SG, VRE, BESS, DER aggregation, electrolyzer
Non-Spinning Reserve	NSR	Active power capacity that, although non-synchronized to the grid, can be readily available within a few minutes under a contingency condition	SG, VRE, BESS, DER aggregation
Replacement Reserve	RR	Active power capacity necessary to restore the levels of SR and NSR to their pre-contingency status	SG, BESS, DER aggregation
Flexible Ramping Capability	FRC	Ramping capability (increase or decrease in active power), provided by flexible resources, online or offline, to follow future movements of net load	VRE, BESS, SG (hydro, gas-fired), DER aggregation

Steady-State Reactive Response	SSRR	Reactive power capacity to maintain the voltage within narrow limits under normal operation	SG, Synchronous Condensers, VRE, Static VAR Compensators, Static Synchronous Compensators, DERs, capacitors, reactors
Dynamic Reactive Response	DRR	Fast reactive power response used during disturbances to recover the voltage to its nominal value	SG, Synchronous Condensers, VRE, Static VAR Compensators, Static Synchronous Compensators, DERs
Fast Post-Fault Active Power Recovery	FPFAPR	Fast recovery of inverter-based generation active power output after a disturbance	VRE
Black Start Capability	BSC	Active and reactive power capacity responsible for starting the power system from a blackout condition	SG, BESS, PHS

Table 1 Proposed definition and potential providers of conventional and new ASs. [3]

The design of competitive AS markets requires adherence to several fundamental operational principles to ensure efficient resource allocation and market functionality; however, no universally applicable prescriptive framework can be uniformly applied across disparate power systems, given the heterogeneity of infrastructural configurations and institutional practices. Each power system operator establishes a distinctive portfolio of ASs calibrated to its specific infrastructural evolution and operational exigencies, necessitating continuous iterative refinement and market architecture modification. Consequently, the transition toward fully decarbonized power systems dominated by VRE sources will likely be achieved through evolutionary enhancement of existing market frameworks, incorporating proven institutional mechanisms and contractual structures demonstrably applicable under high penetration scenarios, rather than through the wholesale replacement of established market designs with novel architecture.

The definition of each AS should be grounded in explicit operational objectives that reflect anticipated system requirements under evolving generation portfolios. The product specification for any AS must be delineated with precision, establishing both technical performance parameters and administrative compliance obligations that prospective service providers must satisfy. The fundamental architectural determinants of an AS market framework—encompassing the procurement methodology, the price discovery mechanism, the remuneration structure, and the cost allocation scheme—collectively constitute critical design variables that establish the operational and economic incentive structures governing market behavior and resource participation decisions.

While FFR and SIR are explicitly defined as system services in some markets (e.g., Ireland's DS3 framework), 'virtual inertia' from grid-forming inverters is more commonly treated as a technical capability in the literature and emerging specifications rather than a widely standardized ancillary-service product. In Europe, procurement mechanisms are now appearing—for example, Germany's TSOs started market-based procurement of inertia/instantaneous reserve (Momentanreserve) on 22 Jan 2026—while in Australia AEMO has published a voluntary grid-forming inverter specification intended to inform future service specifications and procurement. [17] [18] [19] [20]

The formal market-based *Synthetic Inertia Service* that Germany is launching in 2026 represents a critical evolution where synthetic inertia transitions from a technical concept to a procured ancillary service with dedicated market mechanisms. The synthetic inertia market is experiencing rapid growth, valued at $1.8 billion in 2024 and projected to reach $6.2 billion by 2033. [19] [21]

Modern grid codes are now explicitly requiring *Grid-Forming Capability Services* that enable inverter-based resources to actively establish grid frequency and voltage, support black start operations, and provide fault current contribution. These services represent a technology-neutral evolution beyond traditional synchronous compensation. The emerging *Grid Stability Services* framework that system operators are developing encompass a comprehensive approach including inertia provision, short-circuit level support, and system strength services that go beyond individual AS categories. The UK's National Grid ESO Stability Pathfinder program represents this new paradigm, with major contracts awarded through 2022-2024. [22]

Today there is no EU-wide harmonized ancillary-service product officially called "*V2G Frequency Response Service*"; V2G instead participates (or is piloted) inside existing products like FCR and FRR under national TSO rules. Some TSOs and companies are creating V2G-focused tariffs and pilots, but these are still implementations of standard (or "specific") balancing products, not a separate EU-level category. In practice, EV fleets with V2G are used or modelled to provide FCR and sometimes FRR, with aggregators pooling many cars to meet MW minima and activation requirements. Nordic studies show FCR market "flexibilization" (lower minimum bid size and shorter delivery blocks) explicitly improves the economics and feasibility of EV fleets offering FCR via V2G. The Danish Parker project and subsequent Nordic work demonstrated commercial FCR-N provision with aggregated EVs, treating V2G as a technology option for the existing FCR products, not a new product class. In Germany, TenneT–Nissan–The Mobility

House pilots showed V2G cars helping grid stability and redispatch, again framed as flexibility/ancillary services within current market structures.

While not exclusively for V2G, Terna's Fast Reserve (Riserva Ultra-Rapida) pilot is the de facto "specialized" service where V2G shines. It requires extremely fast response (full activation in 1 second) to frequency deviations, a service batteries/V2G can provide much better than thermal plants. The Stellantis Mirafiori "Vehicle-to-Grid" plant (the Drosso project) is the world's largest V2G pilot. It aggregates ~700 EV batteries to provide 25 MW of Fast Reserve to Terna. Because batteries have limited energy, the Fast Reserve pilot includes specific rules for state-of-charge (SOC) management and restoration, allowing the unit to recover energy (recharge) after providing the service. [23]

3 The Role of Distributed Energy Resources

This Chapter discusses the role of distributed energy resources (DERs) towards 100% Renewable Electric Power Systems. It starts with the introduction of the Modelling and Optimization Approaches, Case Studies and Main Results used during the literature review for this thesis where around sixty articles were reviewed and categorized to give an overview of the traditional , novel ideas, and technologies that are promising towards the ambitious goal of 100% renewable energy penetration. The sixty articles chosen for these purposes are organized based on three main categories:

1- Modelling and Optimization Approaches (e.g., MILP/MINLP, stochastic optimization, robust optimization, genetic algorithms, MPC/active control, etc.)
2- Ancillary Service Products and Market Participation (e.g., frequency containment/reserves, aFRR/mFRR, voltage support/reactive power, congestion management, balancing, etc.)
3- System Scope and Flexibility Technologies (e.g., EVs, heat pumps, thermal storage, batteries, CHP, district heating/cooling, PV, flexible loads, aggregators, etc.)

3.1. Literature review

In [24], S. Hanif et al. discussed how can a Battery Energy Storage System (BESS) be optimized and controlled to provide multiple grid services simultaneously, considering different time scales and uncertainties. They developed a two-stage framework: 1) A look-ahead planning stage (Day-Ahead) using Robust Optimization to handle uncertainties (prices, load) and linearize non-convex constraints (power factor). 2) A real-time control stage using sensitivity-based rules to adjust set-points based on actual grid conditions (seconds-to-minutes scale). The model integrates Energy Arbitrage, Frequency Regulation, Demand Charge Reduction, and Power Factor Correction. A utility-scale BESS (1500 kWh / 750 kW) provides services to a large commercial building in the US Pacific Northwest. The study used real historical data for load, prices (energy and regulation), and regulation signals over a one-month period. The proposed multi-service framework improved BESS revenue by 3.7% compared to day-ahead planning alone, primarily through real-time adjustments for regulation services. The framework efficiently handled multiple time scales (hourly planning vs. seconds-level control) and scaled well computationally (solving in ~1 second). It successfully maintained BESS operation within limits while providing all four targeted services. My main observation for this study is the absence of the economic cost models to represent BESS system like net present value that shows the many times the BESS is not economically feasible despite the cost reduction and revenue gained by its installment.

In [25], A. Kumar et al showed how to optimally allocate and operate wind turbines and BESS in active distribution networks, considering both central and distributed ASs. A bi-level optimization framework was solved using a Genetic Algorithm (GA). Level 1 determines optimal sites and sizes of DERs (Wind, BESS, Shunt Capacitors) to minimize annual energy loss. Level 2 performs hourly optimal management for energy and ASs (minimizing load deviation, reverse power flow, power loss, and voltage deviation). A real-life Indian 108-bus distribution system (11 kV network). The study compares three cases: Base case (no DER), Optimal integration of Wind Turbines (WT) only, and Optimal integration of WT and BESS with modern distributed ancillary services (MDAS). The proposed framework with distributed ancillary services (Case III) achieved the highest annual energy loss reduction (48.70%) compared to WT only (42.69%), while enabling higher renewable penetration (31.46% vs 28.85%). It significantly improved the mean power factor to 0.94 (from 0.43 in WT-only case) and reduced voltage deviations and reverse power flow. Central and distributed BESS effectively coordinated to provide peak shaving and frequency support services.

In [26], G. E. Mejia-Ruiz et al. Investigated the idea of how to simultaneously provide multiple ASs (frequency regulation, voltage support, and virtual inertia) in transmission networks using aggregated IBRs to address stability issues in low-inertia grids. Hierarchical Optimal Control Scheme with four layers was used as shown below:

-Layer 4: TSO supervision and setpoint definition.

-Layer 3: Linear Quadratic Gaussian (LQG) controllers for optimal active/reactive power setpoints.

-Layer 2: Aggregator for dispatching power to IBRs based on capacity and State of Charge (SOC).

-Layer 1: Device-level control including virtual inertia using DC-link capacitors.

They used Eigensystem Realization Algorithm (ERA) for black-box modeling as system Identification and Utilized the energy stored in DC-link capacitors of inverters as Virtual Inertia. A modified IEEE 39-bus system was used with 25% non-synchronous generation penetration. They replaced 5 Synchronous Generators with IBRs (Solar, Wind, BESS). They presented the simulation results across four Scenarios: (1) Sudden generation reduction (200 MW to 100 MW), (2) Closed-loop vs Open-loop performance, (3) Three-phase short-circuit fault, (4) Impact of communication latency (0-100 ms). Their results indicated the following:

- **Frequency Stability**: 68% reduction in frequency nadir deviation and 26% improvement in Rate of Change of Frequency (RoCoF) (reduced from 60 mHz/s to 26 mHz/s).
- **Response Time**: Fast frequency and voltage regulation achieved within 100 ms.
- **Voltage Support**: Maintained bus voltages above 0.95 pu during disturbances.

- **Virtual Inertia**: Successfully increased system inertia using DC-link capacitors without additional hardware.
- **Robustness:** System recovered stability within 450 ms after a severe 3-phase fault

They proved that the energy stored in the DC link capacitors can provide several MWs along the first few seconds that are crucial to give the slower response acting devices like governor power generators the sufficient time to arrest this imbalance and determine whether to use or not the protection layer of under-frequency load shedding. The importance of this idea is the possibility of using existing components in grid-installed inverters instead of using dedicated supercapacitors connected to the grid and thus is very economic and can provide voltage support required by some grid codes at the beginning of the imbalance. Furthermore, this inertia support can be extended using BESS systems connected to the inverter.

In [27] , A. Pinnarelli et al. discussed the idea of how to evaluate the actual aggregate contribution of distributed Energy Storage Systems (ESS) operating as a Virtual Energy Storage System (VESS) for synthetic inertia and fast reserve services, considering individual ESS capacity and grid constraints. A Multi-Agent System (MAS) approach was developed with a hierarchical control structure: centralized between DSO and Renewable Energy Communities (REC), and distributed/decentralized among ESSs. The algorithm uses a top-down approach for requests (from TSO/DSO) and a bottom-up approach for actual capability verification (based on State of Charge and Load Flow constraints) and implemented in Python. A portion of a distribution grid with 4 buses and 6 lines, tested in two scenarios: 1) One DSO with a single REC containing 2 ESSs. 2) One DSO with three RECs (aggregated) containing multiple ESSs. Real data for ESS and load characteristics were used. The study demonstrated that the theoretical regulating capacity of ESSs is often significantly reduced by real-world constraints. In Case 1, the effective contribution was only 9.2% of the requested amount (1 kWh vs 10.8 kWh) due to State of Charge limits and grid technical constraints (line currents). In Case 2, the contribution was 9.05% of the request. The MAS approach successfully identified the actual deliverable AS capacity while ensuring grid security.

In [28], P. Mancarella et al. investigated the ability of Distributed Multi-Energy Systems (DMES) to leverage multi-energy arbitrage and provide power system ASs, and what is the optimal profitability. The paper introduces a novel indicator, Maximum Profit Electricity Reduction (MPER), to identify the optimal level of electricity input reduction for ASs. It uses multi-energy profitability maps and break-even maps to visualize profitability based on availability and exercise fees. The approach relies on energy shifting across input vectors (electricity, gas) and plant components (CHP, Heat Pumps, Boilers) without affecting end-use demand. Two illustrative cases for a trigeneration system (CHP + Electric Heat Pump + Auxiliary Boiler): 1) Winter case (EHP in heating mode). 2) Summer case (EHP in cooling mode). Both cases analyze half-hourly periods with specific load profiles and market prices. The maximum profit from providing ASs does not always correspond to the maximum technical electricity reduction (Electricity Shifting Potential - ESP). In many cases, especially with lower availability/exercise fees, the optimal profit (MPER) occurs at an intermediate reduction level (e.g., 10 kWh reduction vs 30 kWh ESP in the winter case). Profitability depends non-linearly on fees due to the complex interaction of component efficiencies and energy shifting costs.

In [29], Metwaly et al. discussed how can BESS be optimally sized (energy and power) for peak demand matching to enhance transmission network reliability, and what are the effects of deploying them alongside Dynamic Thermal Rating (DTR) and Demand Response (DR). A probabilistic evaluation method based on Sequential Monte Carlo (SMC) simulation assesses Expected Energy Not Supplied (EENS) by running DC Optimal Power Flow (DC-OPF) simulations over a year. The method models random component failures, hourly demand variations, DTR based on weather data (using ARMA models for wind), and DR using peak-shaving/valley-filling. The IEEE 24-bus Reliability Test System (RTS), with load levels increased by 5x to stress the network. Weather data for DTR was sampled from UK Met Office data (BADC) for 2000-2019. BESS capacities ranged from 20-100 MWh and 4-80 MW. The combination of BESS, DTR, and DR provided the highest reliability improvement, reducing EENS by up to 37.2%. DTR significantly reduced the need for BESS discharging (by ~6.8%) and utilization (by ~9.8%) compared to static ratings, extending battery life. DR improved reliability up to a specific penetration level (25% of peak load); beyond this, it created new peaks and worsened reliability. Larger BESS units improved reliability but had a more detrimental impact when they failed compared to smaller distributed units.

In [30], Heine et al. showed how can an industrial-sized BESS be used in an urban distribution network to improve power quality and provide ASs like reactive power control and load smoothing with a field testing of a 1.2 MVA / 600 kWh BESS in a live distribution network. The methodology involved implementing and monitoring three specific control modes: 1) Reactive power management (for TSO/DSO connection limits, transformer loss reduction, and BESS self-optimization). 2) Peak shaving/smoothing of rapidly varying metro train loads. 3) Smoothing of solar power plant production fluctuations. Case Helsinki: A 1.2 MVA / 900 kVAr / 600 kWh BESS installed at the Suvilahti 110/10 kV substation in Helsinki, Finland. The site also includes a 380 kWp solar power plant and an EV charging station. The BESS was tested in a strong urban grid environment and successfully managed reactive power to keep the DSO within the TSO's PQ window limits, saving approximately €960 in penalty costs during a test month (September 2018). It also effectively smoothed the rapid load fluctuations from metro trains (up to 12 MW variations) and solar production (using 5s and 15s sampling rates, respectively). The study confirmed that while active power services (frequency control) are most profitable, reactive power support is a valuable additional AS, though it increases BESS losses (estimated cost €272/month).

In [31] , Marchgraber et al. presented the idea of how BESS can efficiently prioritize and allocate limited power and energy resources among multiple conflicting services (functions) during real-time operation, especially under abnormal grid conditions. The authors propose a novel "Dynamic Prioritization" concept for real-time BESS operation. This method dynamically allocates power resources based on assigned priorities when total requested power exceeds BESS capabilities, resolving conflicts between services like Frequency Containment Reserve (FCR), Fast Reserve (FR), Synthetic Inertia (SI), and Voltage Support. A mathematical framework is developed to describe these functions and their interactions. The concept is validated using MATLAB/Simulink simulations (short-term for specific events like short-circuits, and long-term based on historical frequency data). The methodology is applied to several theoretical scenarios simulated on a model of a real 2.5 MVA BESS. Case studies include: 1) A short-circuit event where Dynamic Voltage Support (highest priority) overrides Frequency Control services. 2) A reference incident (frequency deviation) where Fast Reserve and Synthetic Inertia interact with FCR. 3) Long-term simulation (January 2019 frequency data) comparing dynamic prioritization vs. static allocation for FCR and SoC management. The dynamic prioritization concept allows for better utilization of BESS resources compared to static allocation (virtual BESS). It enables the BESS to provide critical high-power services (like Dynamic Voltage Support or Synthetic Inertia) during rare abnormal grid events without reserving idle capacity during normal operation. For example, during a simulated short-circuit, the system successfully prioritized voltage support over frequency services, stabilizing the local voltage while momentarily limiting frequency response. In normal operation, it allowed SoC management to use "slack" power capacity from FCR, improving SoC maintenance without violating FCR requirements.

In [32], Shi et al. discussed how can a joint optimization framework for battery storage performing both peak shaving and frequency regulation yield greater economic benefits than the sum of individual applications ("superlinear gains"). A stochastic joint optimization framework was developed, capturing battery degradation (linear cost model), operational constraints, and uncertainties in customer load and regulation signals. The problem was split into: 1) A day-ahead optimization for capacity bidding and peak shaving thresholds (using MLR for load prediction and scenario reduction for regulation signals). 2) A simple threshold-based online control algorithm for real-time battery operation. Two real-world case studies using data from commercial users: 1) A Microsoft data center (1 MW peak load). 2) The University of Washington EE/CSE building. Both assumed a 1 MW / 15-minute battery, with portions (3-10 minutes) reserved for grid services. Frequency regulation signals were from the PJM market. The study demonstrated a superlinear gain, where the savings from joint optimization were larger than the sum of savings from individual applications. For the Microsoft data center, joint optimization saved $52,282/year (10.7% of the bill), with a "superlinear saving ratio" of 2.71 (saving was ~2.7x higher than the sum of individual benchmarks). For the UW building, the gain was 12.4% with a ratio of 3.91. This gain arises because the random zero-mean regulation signal helps break down long peak loads into shorter intervals, making peak shaving more efficient and less energy-intensive.

In [33], Moazzen et al. investigated how can geographically adjacent microgrids be efficiently clustered and managed to minimize operational costs and emissions, utilizing *shared battery storage* and demand-side flexibility. A two-layer energy management strategy was developed. The lower layer optimizes individual microgrid operations (day-ahead scheduling) using local resources. The upper layer employs a cooperative strategy for the entire cluster (C-EMS), managing a Shared Battery Energy Storage (SBES) system and coordinating power exchanges. The problem is formulated as a Mixed-Integer Quadratic Programming (MIQP) model, solved with the Gurobi optimizer, to handle costs like battery degradation and state-switching (CiOS). A real-world case study was conducted using data from a cluster of three grid-connected microgrids in New South Wales, Australia. Each microgrid contained PV units, conventional gas generators, and local battery storage, but with different load profiles and capacities. The study used real Australian market price data and solar irradiance profiles. The proposed two-layer strategy reduced operational costs by 6.96% (saving ~$92/day) compared to conventional individual microgrid management. Sensitivity analysis showed potential savings ranging from 6.5% to 8.1% depending on SBES capacity and flexibility pricing. Additionally, the strategy reduced CO_2 emissions by up to 11.6% by prioritizing renewable usage and minimizing reliance on the main grid and fossil-fuel generators.

In [34], Koltsaklis et al. addressed how does the co-optimization of energy and reserve markets, incorporating diverse flexibility providers (EVs, ESS, DRPs) alongside conventional units, impact operational costs, CO_2 emissions, and RES curtailment in a high-RES power system. A detailed mixed-integer linear programming (MILP) model was developed to co-optimize day-ahead energy and ASs markets. The model integrates detailed unit commitment for conventional plants with flexible resources: Energy Storage Systems (ESS) (charge/discharge), Electric Vehicles (EVs) (G2V/V2G), and Demand Response Programs (DRPs). It accounts for upward and downward reserves (FCR, aFRR, mFRR). The problem was solved using CPLEX in GAMS. An illustrative case study of a power system with high renewable penetration (Wind, PV) and conventional thermal/hydro units. Five scenarios were analyzed:
1) EVs (G2V only), 2) EVs (G2V + V2G), 3) EVs + ESS, 4) EVs + ESS + DRPs (energy market only), 5) All flexibility providers (EVs, ESS, DRPs) participating in both energy and ASs markets. Input

data included 100,000 EVs, 3 generic ESS units (1000 MWh max), and flexible loads (30% flexibility). Integrating all flexibility providers (Case 5) significantly outperformed the baseline (Case 1). It reduced total daily operational costs by 38.9% and CO2 emissions by ~43% (due to displacing lignite units). RES curtailment was completely eliminated in Case 5 (from 3821 MWh in Case 1). The number of thermal unit start-ups/shut-downs decreased, enhancing system reliability. Flexibility providers supplied 71% of daily aFRR-up requirements in the fully integrated scenario, demonstrating their capability to replace conventional reserves.

In [35], Lampropoulos et al. discussed how a generic, hierarchical control framework enables aggregators to provide flexibility services to both Transmission (TSO) and Distribution System Operators (DSO), considering potential conflicts and market optimization (energy arbitrage). A hierarchical control framework was proposed, featuring decentralized decision-making and distributed computation to preserve user privacy. It includes: 1) Operational Planning: Optimizing day-ahead energy schedules. 2) Real-time Operations: A feedback control loop where aggregators broadcast set-points and users (equipped with Home Energy Management Systems) optimize their response voluntarily. 3) Conflict Resolution: Specific rules for TSO-DSO conflicts (e.g., giving priority to local grid congestion management). The model was simulated in MATLAB using historical Dutch market data (2016). A case study of a Low Voltage (LV) distribution grid in the Netherlands with 50 residential users (divided between two aggregators), each equipped with PV systems and battery storage (Tesla Powerwall 2). Three scenarios were simulated: Scenarios 1 & 2 varied forecast errors (low vs. medium) with a standard transformer capacity (125 kW). Scenario 3 simulated a "stressed" grid with high forecast errors and reduced transformer capacity (90 kW) to trigger frequent congestion. Aggregator 1 (combining day-ahead energy arbitrage with ASs) consistently generated higher total profits than Aggregator 2 (ASs only). However, Aggregator 2 achieved higher profit per unit of flexibility provided. In Scenario 3 (stressed grid), revenues from peak shaving (DSO) surged significantly (e.g., from ~€800 to >€5000), while revenues from TSO balancing services decreased due to capacity conflicts. The study showed that increased forecast errors had a relatively minor impact on overall profitability, but grid constraints heavily influenced the value distribution between TSO and DSO services. High peak shaving costs signal DSOs to invest in grid reinforcement.

In [36], Oshnoei et al investigated how can a Virtual Power Plant (VPP) comprising BESS and Heat Pump Water Heaters (HPWHs) effectively participate in load frequency control (LFC) in a coordinated manner, minimizing regulation costs while managing communication delays. A coordinated control strategy for VPPs was proposed, distributing regulation signals between Conventional Generation Units (CGU) and the VPP. A multi-objective optimization was used to determine optimal distribution coefficients, balancing dynamic regulation performance and total regulation cost. A Brain Emotional Learning (BEL) supervisory coordinator was developed to mitigate frequency deviations caused by communication delays. The method was validated using MATLAB/Simulink and a real-time OPAL-RT simulator. A case study on the New England 10-generator 39-bus test system, divided into three control areas. The VPP (located in Area 1) consisted of a BESS aggregator (10 units, 9.85 MWh total) and two HPWH aggregators (117,000 units, ~11.7 MW total). The system faced an 80 MW load increase contingency. Robustness was tested against parameter uncertainties and communication delays (0-10s). The proposed coordinated control strategy significantly outperformed non-coordinated schemes and CGU-only control. It reduced the absolute maximum frequency deviation to 0.9772 Hz (vs. 1.27 Hz without coordination) and lowered the total regulation cost to $659.9 (vs. $685.3). The BEL coordinator effectively managed communication delays, preventing excessive power injection/withdrawal and maintaining stability even with long delays (e.g., 6s). The optimization showed that allocating ~50% of the regulation signal to the VPP provided the best trade-off between cost and performance.

In [37], Kong et al. showed how to plan backup capacity for flexible and adjustable resources (source, load, storage) in port areas with a high percentage of renewable energy to ensure system stability and economic efficiency. A two-layer optimization model was proposed: 1) Planning Layer: Maximizes annual revenue minus costs (investment & operation) to determine optimal capacities of gas turbines, storage, and demand response. 2) Operation Layer: Minimizes operating and backup costs by coordinating resources. A hybrid Population Migration Particle Swarm Optimization (PMPSO) algorithm was developed to solve the problem, offering better global search capability than traditional PMO or PSO. A green seaport in China with a high penetration of renewables (39 MW wind, 3.9 MW PV). The study compared four scenarios: 1) Conventional planning (no demand response preference), 2) DR participation only in energy regulation (not planning), 3) Standby service without DR preference, and 4) The proposed method (comprehensive flexible resource planning). The proposed method (Scenario 4) achieved the lowest total annual cost (13.83 million RMB) compared to other scenarios (e.g., 14.24M for Scenario 1). It reduced the operating costs of the port distribution system by 24.61% by effectively utilizing demand response (33.24 MW planned) and optimizing gas turbine usage (38 MW planned). The PMPSO algorithm outperformed other methods, reducing configuration costs by 8.84% compared to PSO and providing better reliability than the maximum single-machine method. The study confirmed that coordinating source-load-storage backup resources significantly improves economic efficiency and renewable energy consumption.

In [38], Pandey et al. explained how can a Virtual Power Plant (VPP) optimize both net profit and emissions reduction by integrating multiple renewable sources (PV, wind), co-generation (CHP, FC), and using EVs as flexible reserves and ESS as spinning reserves. A Multi-Objective Day-Ahead Scheduling (MODAS) framework was developed using a weighted sum approach to balance profit maximization and emission minimization. The problem was solved using the Multi-objective Harris Hawks Optimization (MOHHO) algorithm, a metaheuristic technique chosen for its ability to handle non-linear problems. The model incorporates a dynamic pricing (Peak-Valley Pricing) strategy and a penalty factor approach for constraint handling. The study utilizes a theoretical VPP system comprising wind turbines (150 MW rated), solar PV modules, CHP units (Type I & II), fuel cells, Heat-Only Units (HOU), EVs as flexible reserves, and ESSs as spinning reserves. Four illustrations were analyzed across three cases: 1) Profit Maximization, 2) Emission Minimization, and 3) Multi-objective optimization. The proposed MOHHO method significantly outperformed other techniques like MOPSO. In the Multi-objective scheduling (Case III), the VPP achieved a maximum net profit of $28,895.3 (compared to $23,302.8 with MOPSO) and minimized emissions to 53,800.2 kg (compared to 64,432.3 kg with MOPSO). Integrating EVs as flexible reserves and ESS as spinning reserves, along with the penalty factor method, increased net profit by 10.32% and reduced emissions by 8.48% compared to scenarios without reserves. The dynamic pricing strategy further enhanced revenue during peak periods.

In [39], Ikuta et al. discussed how can a price-based demand response (PDR) scheme with a two-stage incentive design (Day-Ahead and Hour-Ahead) enable DERs to provide flexibility (specifically Replacement Reserve for Feed-in Tariff) in the Japanese market. A Multi-timescale simulation model (Day-Ahead, Hour-Ahead, Real-Time) was developed. It uses a two-stage incentive design: 1) Real-Time Incentive (RTI) ranges set in the Day-Ahead stage to estimate available flexibility, and 2) Specific RTI rates set in the Hour-Ahead stage to finalize flexibility procurement. The model employs MILP for optimal operational planning and rule-based control for real-time operation. A simulation of 20 detached houses in Japan, each equipped with various DERs (PV, Fuel Cells (SOFC/PEFC), Batteries, Heat Pumps). The simulation covered two days in April, using real-world data for demand and solar radiation. The proposed scheme effectively procured flexibility: 77% for downward flexibility and 85% for upward flexibility in the Day-Ahead stage. In the Hour-Ahead stage, it achieved 70% (downward) and 63% (upward) procurement in real-time. The demand shifts induced by the incentives reduced supply-demand imbalances in 29 out of 96 time steps, with an average imbalance reduction of 76% per time step. The study highlighted the specific characteristics of different DERs: Fuel cells were easiest to manage via price signals, while batteries and heat pumps faced constraints due to state-of-charge and thermal storage levels.

In [40], Liu et al. showed how can a Virtual Power Plant (VPP) composed of interconnected microgrids (IMGs) with different load profiles use a combinatorial auction mechanism (CAM) for peer-to-peer (P2P) energy trading to minimize RegD-following violation and operating costs in the demand-side ASs market. A two-stage optimization model was proposed: 1) Day-ahead: Optimizes baseline and regulation capacity using RNN for forecasting. 2) Real-time: Distributes RegD signals and uses a CAM-based P2P energy trading mechanism (solved via Particle Swarm Optimization) among MGs to minimize RegD-following violations. This was compared with two Stackelberg game-based methods (Buyer-leader and Seller-leader) and a no-trading scenario. A modified IEEE 118-bus test system divided into 8 interconnected microgrids (IMGs): 1 commercial (MG1), 1 heavy industry (MG8), and 6 residential MGs. The VPP included 33 Distributed Generators (DGs) and 10 Energy Storage Systems (ESSs). Simulation was conducted over a one-year period (results shown for one day). The VPP using CAM-based P2P trading (Scenario iii) achieved the lowest RegD-following violation (1.3863 MWh) and the lowest total operating cost ($91,483.31) compared to other scenarios (e.g., $94,812.87 for no trading). CAM-P2P reduced total costs by 3.64% compared to the no-trading case. It also had the shortest computation time (~19.58s for 288 intervals) compared to Stackelberg game methods (~20.2s), making it more practical for real-time applications. MGs with stable loads (commercial/industrial) profited more from trading than residential ones.

In [41], Zhao et al. investigated how to optimally determine the sizing and siting of BESS in high-renewable penetration power systems to mitigate grid vulnerability and maximize economic benefits. A trilevel optimization model was proposed: 1) Upper-level (Pre-optimization): Uses a Global Vulnerability Index (GVI) based on voltage stability and connection loss to filter potential BESS sites. 2) Middle-level (Sizing & Siting): Determines optimal capacity and power using Improved Particle Swarm Optimization (IPSO) to maximize equivalent annual revenue. 3) Lower-level (Operational): Optimizes daily operation scheduling using Improved Butterfly Optimization Algorithm (IBOA) to maximize expected revenue from arbitrage, frequency regulation, and peak shaving. An extended IEEE 33-bus distribution system connected to a main grid and including two photovoltaic power stations. The simulation used historical load, wind, and solar data (clustered into 4 typical seasonal scenarios) and market price data (PJM market). Configuring BESS at critical nodes (identified as node 5) improved the Global Vulnerability Index to 0.282, significantly enhancing grid stability. The optimal strategy (Scheme 3: multi-market participation) increased annual revenue by ¥1.4 million compared to conventional strategies (Scheme 2) and shortened the investment payback period by 0.4 years (to approx. 6 years). Frequency regulation revenue contributed ~40% of the annual income, highlighting its economic importance.

In [42], Liu et al. addressed the opportunities, technologies, and challenges for building energy systems to provide flexibility services via power-to-heat technology, considering both supply and demand sides. A comprehensive review and theoretical framework analysis. It discusses four key aspects: 1) Quantitative indicators based on thermal inertia (Key Performance Indicators like energy efficiency, time control, cost reduction). 2) Model Predictive Control (MPC) for building flexibility (comparing white-box, gray-box, and black-box/data-driven models). 3) Flexible system optimization (using 6E analysis: Energy, Electricity, Exergy, Entropy, Economy, Environment). 4) Applications for flexible services in engineering and sociology. No specific experimental case study was conducted by the authors themselves, but they reviewed numerous existing studies and demonstration projects (e.g., zero-emission building in KhshU, flexible BIPV in Turkey, community-scale residential systems). The paper identifies thermal inertia as a crucial bridge between supply and demand, allowing load shifting without compromising comfort. Model Predictive Control (MPC), particularly gray-box and data-driven models, is essential for managing unpredictability in renewable energy and demand. 6E analysis provides a holistic framework for optimizing flexible systems. The transition from rigid to flexible building energy systems can significantly reduce carbon emissions and operational costs, but requires advanced control strategies and policy support to overcome technical and societal barriers.

In [43], Chong et al. investigated how to enhance the adaptability and flexibility of a large-scale Virtual Power Plant (VPP) by integrating industrial-scale Interruptible Load Energy Storage (ILES) while ensuring operational safety and frequency stability. A dynamic simulation model was developed for a large-scale VPP (using APROS software) integrated with an ILES. A coordinated control strategy was proposed, involving: 1) Determining dispatching time and range. 2) Three power calculation schemes (PUS - Power Universality Scheme, PES - Power Enhancement Scheme, PAS - Power Attenuation Scheme). 3) Control system optimization (using Optimization Functions) to improve dispatch rates and frequency stability. A simulation of a large-scale VPP comprising a 350 MW coal-fired unit, a 100 MW PV unit, electric bus fleets (96 MWh per group) as main energy storage, and a monocrystalline silicon industry load as the ILES. The study used typical daily power demand curves (e.g., Summer Solstice, Winter Solstice, Jan 6th, Aug 16th) from Shaanxi Province, China. The proposed strategy significantly improved system performance: The ILES dispatch rate increased from 10 MW/min to 40 MW/min while maintaining frequency stability (<0.2 Hz deviation). Adjusting dispatch times increased ILES dispatching power from 53.7 MW to 101.8 MW and VPP output energy from 16.9 MWh to 96.7 MWh. Under different schemes, dispatching power varied significantly (e.g., 27.5–107 MW), enhancing flexibility. The strategy allowed the VPP to effectively manage renewable fluctuations and participate in ASs.

In [44], Pandey et al. addressed the idea of how to optimize the operation and scheduling of a multi-area Virtual Power Plant (MAVPP) comprising renewable energy sources, co-generation units, and flexible storage to maximize net profit and minimize emissions. A novel Multi-Area Virtual Power Plant (MAVPP) framework was proposed, connecting two areas via a tie-line. A Marine Predator Optimization Algorithm (MPOA) was employed for day-ahead optimized scheduling. The problem was formulated as a multi-objective optimization (maximizing net profit, minimizing emissions) using a Pareto-based approach. Results were compared with Particle Swarm Optimization (PSO) and Genetic Algorithm (GA). A simulated two-area interconnected power system containing flexible resources: solar PV, wind power, fuel cells, Combined Heat and Power (CHP) units, EVs as flexible reserves, and ESSs as spinning reserves. The study analyzed two scenarios: single-area (for validation) and the proposed multi-area VPP. The proposed MPOA technique outperformed PSO and GA. For the MAVPP scenario, the maximum net profit converged to \$59,351.88 (compared to ~\$58,978 for PSO), and minimum emissions were reduced to 51,700.73 Kg (compared to ~52,700 Kg for PSO). The computational time was significantly lower (92.96s for profit maximization vs. 122.41s for PSO). The multi-area configuration showed superior economic benefits compared to single-area systems, though with slightly higher total emissions due to dual co-generation units.

In [45], Fatemi et al. took into account the question of how to unlock the flexibility of demand-side resources (EV fleets, flexible loads) and grid-connected storage systems (coordinated by a Virtual Storage Plant) in a decentralized, privacy-preserving manner to address power imbalances in renewable-based grids. A decentralized bi-level optimization framework was proposed. The upper level represents the TSO minimizing balancing costs, and the lower level represents balancing service providers (Virtual Storage Plant, EV parking lots, flexible loads) maximizing profits. An adaptive Alternating Direction Method of Multipliers (ADMM) was employed to solve the problem with limited information exchange, updating penalty coefficients and prices iteratively to ensure fast convergence. A modified IEEE 30-bus transmission system with 15-minute resolution was used. The system included renewable sources (wind, PV), dispatchable units, and flexible resources: a Virtual Storage Plant (VSP) coordinating Battery Energy Storage (BES), Pumped Hydro (PHES), and Compressed Air Energy Storage (CAES); 6 EV parking lots; and 6 flexible load (FL) locations (residential and industrial). The proposed framework achieved significant improvements: 18.7% reduction in daily TSO balancing costs (12.8% from demand-side resources, 6.7% from VSP). Transmission losses decreased by ~12%, and voltage profiles improved. The adaptive ADMM converged 60% faster (146 fewer iterations) than the standard ADMM, demonstrating superior computational efficiency and scalability for real-time markets while preserving privacy.

In [46], Vanegas et al. discussed how to optimally place, size, and schedule hourly operations of BESS and PV-DG in distribution systems to minimize costs and losses, ensuring global optimality. A MILP model was proposed for the simultaneous placement, sizing, and multi-period operation of BESS and PV-DGs. The model linearized voltage and current constraints (using tangent line approximation and discretization) to guarantee global optimality, unlike metaheuristic methods. It was implemented in AMPL and solved with CPLEX. Tested on the IEEE 33-bus, 69-bus, and a practical 136-bus distribution system (a simplified Brazilian network). The study used a single daily load profile and PV generation curve based on historical Colombian utility data. The model achieved significant improvements: In the 69-bus system, peak demand was reduced by 30.8%, substation energy by 53.9%, and annual energy losses by 43.6%, with a total economic benefit of 36.9%. In the 136-bus system, peak demand dropped by 5%, losses by 27%, and substation energy by 15%, yielding a 7.4% economic benefit. The model consistently provided globally optimal solutions with superior computational efficiency compared to metaheuristics.

In [47], Habib et al. investigated how to optimally coordinate DERs across smart homes, microgrids, and the DSO in a hierarchical manner to minimize costs and improve reliability without centralizing all decisions. A tri-level hierarchical optimization framework was proposed, involving: 1) Smart homes (optimizing local PV, battery, EV); 2) Microgrids (aggregating homes, managing wind, fuel cells, P2P trading); 3) DSO (managing network limits, central generation, prices). A Hierarchical Distributed ADMM (Hier-ADMM) algorithm was developed to decompose the large-scale MILP problem into level-specific subproblems, ensuring convergence and privacy. It was Tested on IEEE 33-bus and 69 bus distribution systems. The 33-bus system included 3 microgrids and 125 smart homes. The 69-bus system was larger, with 8 microgrids and over 400 smart homes, incorporating high renewable penetration (PV, wind) and hydrogen integration (fuel cells, power-to-gas). The tri-level framework significantly outperformed decentralized and two-level approaches. In the 33-bus system, daily operating costs fell by ~12% (to $55,900) vs. decentralized, with network losses dropping from 4.1% to 3.3% and peak line loading from 90% to 80%. In the 69-bus system, costs decreased by ~10% (to $151,100), reducing losses to 3.5% and peak loading to 81%. The Hier-ADMM algorithm converged efficiently (under 2 hours for the 69-bus system) and proved robust under high renewable uncertainty.

In [48], Araghi et al. discussed the question of how to manage energy and ASs markets in a coordinated way between transmission and distribution systems, leveraging demand-side flexibility (SS, PEVs, DR) in a decentralized manner. A two-level decentralized Mixed-Integer Quadratically Constrained Programming (MIQCP) model was proposed. Level 1 handles the Day-Ahead energy market (bids/offers, market clearing) and Level 2 manages ASs (spinning reserve, real-time regulation). Uncertainties (load, wind, solar) were handled using a scenario-based stochastic approach with ScenRed reduction. Solved using CPLEX in GAMS and Tested on a modified IEEE 30-bus transmission system connected to four IEEE 33-bus distribution systems. It included 6 thermal units, 3 wind farms, and various distributed resources (PV, gas turbines, storage, PEVs, DR) across the distribution networks. Integrating distribution systems into reserve/regulation markets significantly reduced costs. Scenario 5 (with DR) showed the lowest regulation costs, reducing them by 6.56% compared to the base case (no DR). The model alleviated transmission congestion and improved voltage profiles during peak hours.

Computationally, it was ~2x faster than centralized and ~89x faster than ADMM-based methods (29.6s vs. 71.1s and 2631s), making it suitable for real-time applications while preserving privacy.

In [49], Wu et al. investigated how to optimize the balancing of regional power systems by integrating Virtual Power Plants (VPPs) as independent Balancing Responsible Parties (BRPs) within a Balancing Group Mechanism (BGM). A bi-level optimization model was proposed. Upper level: Minimize regional system operational costs (generation, balancing, load management). Lower level: Maximize VPP profit as an independent BRP (service revenue, arbitrage, minus penalties). The problem was modeled as a Stackelberg game and solved using Particle Swarm Optimization (PSO). A regional case study was conducted using 24-hour typical deviation data from a region with PV, wind, and user loads. The VPP managed two balancing groups (A and B) containing energy storage, small gas turbines, and interruptible loads. The proposed VPP-as-BRP mechanism reduced regional system operational costs by 29.1% compared to traditional centralized regulation and increased VPP revenues by 24.9%. The model effectively balanced deviations (minimizing penalties) while allowing the VPP to profit from arbitrage and service fees, demonstrating a replicable pathway for balancing mechanisms in renewable-heavy systems.

In [50], Siano et al. discussed how to coordinate multiple Local Energy Communities (LECs) to jointly provide flexibility for ASs markets while preserving privacy and maximizing shared energy incentives. A decentralized optimization method was proposed to coordinate LECs. It introduces a global constraint (minimum power flexibility) managed by a virtual layer using penalty terms and iterative updates, allowing LECs to optimize locally while meeting global requirements. The objective maximizes AS remuneration and shared energy incentives (linearized for tractability) subject to network constraints (DistFlow model, including losses and voltage). Analyzed two LECs (EC1, EC2) connected to an 84-bus radial distribution test system during summer and winter days. Each LEC included prosumers with PV and battery systems. Scenarios included operations with and without internal Peer-to-Peer (P2P) energy exchanges. The decentralized coordination allowed LECs to jointly meet the 300 kW minimum flexibility requirement, which they could not meet individually. In summer, coordination increased EC1's objective from ~€659 to €2154 and EC2's from ~€745 to €1601, with AS revenues outweighing the slight reduction in shared energy incentives. Coordinated solutions deviated by <1% from local optimal targets. P2P trading reduced energy costs but slightly lowered AS potential in winter due to lower PV output.

In [51], Cardo-Miota et al. investigated how to maximize profits for a collocated RES and BESS participating in multiple markets (day-ahead energy + ASs) while managing battery degradation. A Deep Reinforcement Learning (DRL) approach using the Twin Delayed Deep Deterministic Policy Gradient (TD3) algorithm was proposed. It uses an Actor-Critic architecture with LSTM networks to handle continuous action spaces and temporal patterns. A novel non-linear battery degradation model (based on Depth of Discharge) was integrated into the reward function within a Markov Decision Process (MDP) framework. It focused on the Irish electricity market using 2022 historical data. The system included a 7 MW solar PV plant and a 1 MW / 1 MWh Li-ion BESS. Markets considered were the Day-Ahead Market (DAM) and the DS3 ASs program (Frequency Response). The TD3 agent outperformed benchmark strategies (PV+DAM only and PV+DS3 only) and a standard DDPG agent. It achieved total annual profits of €709,461, which was €8,271 more than the PV+DS3 strategy, €166,738 more than PV+DAM, and €11,369 more than the DDPG agent. It effectively balanced arbitrage and reserve provision while minimizing battery degradation costs.

In [52], Mussawar et al. discussed how can a hybrid energy storage system (HESS) comprising Li-ion batteries (LIB) and Reversible Solid Oxide Fuel Cells (RSOFC) profitably participate in multi-energy (electricity and hydrogen) arbitrage in wholesale electricity markets. A linear optimization model was developed to maximize annual profits (or minimize costs) by optimizing the technology selection, sizing, and operation of a HESS. It evaluates two scenarios: electricity-only arbitrage and multi-energy (electricity + hydrogen) arbitrage, assuming perfect price foresight and price-taker behavior. A case study in the United States covering four wholesale electricity markets: CAISO, ERCOT, PJM, and MISO, using real-time historical hourly price data from 2020-2023. The study compared the performance of standalone LIB, RSOFC, and hybrid configurations. Electricity-only arbitrage was largely unprofitable in most markets (except ERCOT in later years) due to high capital costs, requiring >35% cost reduction for profitability. However, multi-energy arbitrage (selling electricity and hydrogen) was highly profitable, generating profit margins of at least 20% in all markets without needing technology cost reductions. In ERCOT (2021-2023), margins exceeded 45% with a hybrid system. RSOFC enabled valuable electricity-to-hydrogen arbitrage, mitigating commercial risks associated with electricity-only trading.

In [53], Prakash et al. addressed the question of what are the opportunities, challenges, and potentials of active neighborhood resources (DERs and smart flexible loads) to participate in Fast Frequency Control (FFC) services. The paper conducts a comprehensive review of technical, regulatory, and economic aspects of FFC from active neighborhoods. Additionally, it demonstrates a coordinated Synthetic Inertia Control (SIC) model for DERs. The control strategy uses a Fuzzy Logic controller (tuned with Particle Swarm Optimization - PSO) to determine optimal synthetic inertia and damping coefficients for Fast Frequency Response (FFR). A dynamic microgrid model simulation incorporating various DERs: small-scale wind turbine generator (WTG), photovoltaic (PV) generator, diesel engine generator (DEG), fuel cell, and energy storage. The system was tested under disturbance conditions (load step changes at 15s and 70s) to evaluate frequency stability. The proposed coordinated SIC strategy significantly improved frequency stability. It reduced the RoCoF by approximately 94% (from 1.16 Hz/s to 0.07 Hz/s) and improved the frequency nadir by roughly 80% (reducing deviation from 0.10 Hz to 0.02 Hz) compared to the case without SIC. The study concludes that active neighborhood resources are credible candidates for providing reliable FFC services.

In [54], Oskouei et al. discussed how to satisfy security and flexibility requirements of multi-district Distribution Companies (DISCOs) under uncertainty while respecting the economic interests of privately owned Virtual Energy Storage Systems (VESSs). A single-leader multi-followers stochastic bi-level optimization model was developed. The upper level (DISCO) minimizes congestion and sets local flexibility setpoints (minimum spinning reserve). The lower level (VESSs) maximizes profit by participating in day-ahead, reserve, and real-time markets. The model was converted to a single-level MILP using Karush-Kuhn-Tucker (KKT) conditions and Big-M linearization. DIgSILENT PowerFactory was used for contingency analysis validation. A modified IEEE 33-bus test system divided into three districts (residential, commercial, and critical users), each hosting a VESS containing DGs, BESS, PVs, and EV parking lots. The study simulated 24-hour operations under uncertainty (PV, load, EV behavior) and N-2 contingency scenarios. The proposed flexibility-oriented strategy (Case 3) significantly enhanced grid resilience compared to baseline cases. It increased the Spinning Reserve Index (SRI) by up to 42.73% on average across districts while slightly reducing the Self-Sufficiency Index (SSI). The strategy effectively mitigated congestion in critical feeders (keeping loading below 80%) and maintained voltage stability (~1.0 p.u.) even under severe N-2 contingencies, proving the trade-off between VESS profit (~8.5% reduction) and grid security is viable and beneficial.

In [55], Wenbo Ma et al. investigated how to enhance the energy efficiency of heating systems for small residential buildings by integrating active solar phase change thermal energy storage (PCTES) with passive building envelope retrofits. A dynamic simulation model was developed using TRNSYS (Transient System Simulation Tool) coupled with GenOpt (for optimization using the Hooke-Jeeves algorithm). The study modeled a synergistic system combining active PCTES (paraffin-based) and passive envelope retrofits (thermal storage walls, optimized window-to-wall ratio). Performance was evaluated using Solar Fraction (SF), energy consumption, and economic metrics (NPV, payback period). A 105 m² single-story residential building located in southern Shaanxi, China (cold winter climate). The case study compared three scenarios: System 1 (PCTES + envelope retrofit), System 2 (PCTES + conventional building), and System 3 (Conventional water tank storage + conventional building). The proposed system (System 1) reduced the building's heating load by 48.1% compared to a conventional structure. The optimized solar fraction (SF) reached 61.8%, significantly higher than System 2 (40.6%) and System 3 (29.3%). The system achieved an annual carbon emission reduction of 1,189 kg CO_2 and a 20.2% reduction in operating costs after optimization (collector area 37 m^2). The return on investment was estimated at 13 years (considering subsidies).

In [56], Jiang et al. discussed how to effectively coordinate TSOs, DSOs, and Charging Station Operators (CSOs) to unlock flexibility from EVs in a coupled power-transportation network while preserving privacy. A two-stage TSO-DSO coordinated dispatching framework (day-ahead and real-time) was proposed. It decomposes the problem into three sub-models: TN-level market clearing (TSO), ADN-level market clearing (DSO), and EV/CS optimization (CSO). An Adaptive Alternating Direction Method of Multipliers (A-ADMM) algorithm with self-adaptive step size was used to solve the distributed optimization problem, protecting data privacy. McCormick relaxation linearized non-convex terms. Two test systems were used: 1) T30-D42-R32 (IEEE 30-bus TN + 42-node ADN + 32-node transport network). 2) T1182-D-2-R (IEEE 118-bus TN + IEEE 33/69-node ADNs + transport networks). Scenarios compared uncoordinated vs. coordinated operation, different weather/speed impacts on EVs, and V2G participation. The proposed coordination framework significantly reduced operating costs for all stakeholders. In the T30-D42-R32 case with full coordination (Case 7), CSO operating costs dropped by ~39%, and ADN costs by ~9% compared to uncoordinated scenarios. TN costs decreased by ~1%. The A-ADMM algorithm reduced iteration count by 44.9% and convergence time by 35% compared to standard ADMM. Incorporating traffic and temperature constraints improved EV load estimation accuracy (~13-15% increase in charging demand).

In [57], Ximu Liu et al. investigated how to optimize day-ahead and intra-day market bidding and on-site scheduling for an Integrated PV-ESS-EV Station (IPEES) under temporally correlated uncertainties in prices, PV generation, and EV demand. A multi-stage stochastic optimization model was developed. Uncertainties were modeled using a non-homogeneous Markov chain with DBSCAN clustering to capture temporal correlations. The problem was solved using a Markov Chain Stochastic Dual Dynamic Integer Programming (MC-SDDiP) algorithm, which uses Monte Carlo resampling to generate robust cuts and avoid traversing the entire scenario tree. A case study on a PJM-calibrated IPEES was conducted. The station includes 1MW PV, 1MW/2MWh ESS, 30 EV charging piles (60kW each), and a battery swapping station. The study simulated a 24-hour horizon with hourly day-ahead bidding and 15-minute intra-day rebidding (6 sessions). The proposed strategy significantly improved economic performance. Joint bidding in energy and ASs markets turned a baseline loss (without ASs) of -102.74 (currency units) into a profit of up to 47.53 (in scenarios with downward reserve calls). The MC-SDDiP algorithm demonstrated high scalability and accuracy, achieving a low optimality gap (~0.1%) even for large-scale problems (10^6 scenarios) where classical Nested Benders Decomposition failed to converge efficiently.

In [58], Yan Yao et al. discussed how to optimally dispatch a Hybrid Energy Storage System (HESS) composed of compressed air (AA-CAES) and vanadium flow batteries (VRB) to provide multiple auxiliary services (Peak Shaving - PS, Frequency Containment Reserve - FCR, Secondary Frequency Regulation - SFR) and support Distributed Generation (DG). A multi-timescale hierarchical optimal dispatch model (Daily Baseline - Regulation Basepoint - Real-time Regulation, DB-RB-RF) was proposed using stochastic optimization. It introduces an idle-time reuse response strategy to create a "virtual ESS" from remaining capacity for SFR. The model optimizes across three timescales: day-ahead (PS allocation), intra-day (FCR/SFR capacity), and real-time (frequency response), solved using GUROBI. A modified IEEE 33-node system with a 650 kW wind farm. The HESS consists of a 2500 kWh / 400 kW VRB and a 960 kW AA-CAES. Real-world wind and load data from Henan Province, China, were used to simulate operations over a year under different market conditions. The proposed joint optimization strategy increased comprehensive income by 4.87% and auxiliary service income by 15.2% compared to operating the two storage types separately. Participating in the SFR market generated significant additional value (60-90% of economic value). The hierarchical approach effectively managed the different response speeds and capacities, realizing stackable benefits from PS, FCR, and SFR while supporting renewable integration.

In [59], Ponnaganti et al. showed how flexibility provisions can be designed for energy communities and how their market activities can be made noticeable, and what social/economic barriers exist. A comprehensive literature review of flexibility mechanisms (Price-based and Incentive-based Demand Response), market designs (Local Flexibility Markets, Peer-to-Peer), and barriers. It integrates findings from EU Horizon 2020 projects SERENE and SUSTENANCE. The review draws on pilot sites from the SERENE and SUSTENANCE projects in Denmark, The Netherlands, Poland, and India, specifically highlighting Danish demonstrators focusing on smart control of heat pumps and EV charging. Local Energy Communities (LECs) can effectively provide grid flexibility through aggregation and demand response. However, significant barriers exist, including undefined aggregator roles, lack of ICT infrastructure, and regulatory rigidities. Local Flexibility Markets (LFMs) and P2P trading are identified as key enablers, but require new regulatory frameworks and better coordination between DSOs, TSOs, and aggregators to succeed.

In [60], Li Li et al. discussed how to balance the conflicting interests of agents (e.g., Energy Retailers, Load Aggregators) and flexibly manage resources in community Multi-Energy Systems (MES) under multi-time scale scheduling (day-ahead and intra-day). A self-approaching optimal scheduling framework was proposed. It uses a Nash-type game model (linearized via separable programming) for day-ahead planning to ensure fair benefit allocation. For intra-day real-time scheduling, a Lyapunov optimization approach with an event-triggered mechanism is used to handle uncertainties and minimize deviations from the day-ahead equilibrium without requiring forecast data. A residential community in Shanghai, China, simulated over three typical seasonal days (summer, transition, winter). The system includes PV, CHP, gas boilers, heat pumps, absorption/electric chillers, and flexible household loads (e.g., HVAC, EVs). The framework successfully balanced agent benefits. In the winter day-ahead scenario, it avoided a 90.05% profit loss for the Energy Retailer while achieving 13.15% cost savings for the Load Aggregator. The intra-day self-approaching optimal approach maintained fairness under uncertainty; for instance, in a specific event (Event 2), it prevented a scenario where 79.98% of profit was sacrificed to achieve excessive cost reduction, ensuring a fairer allocation compared to traditional methods.

In [61], Babazadeh et al. investigated how to integrate the storage capabilities of Plug-in Electric Vehicles (PEVs) via a Virtual Storage Plant (VSP) framework to provide local and global grid services (congestion relief, regulation) in interaction with other storage systems and flexible loads. A Virtual Storage Plant (VSP) framework was proposed, comprising Parking Lot Aggregators (PLAs), Local Service Providers (LSPs), and Global Service Providers (GSPs). The methodology uses a Mixed Integer Quadratic Complex Programming (MIQCP) approach to solve the optimal demand response problem across three market tiers: pre-scheduled, intra-day, and balancing markets. A decentralized algorithm based on primal-dual residuals was used for coordination. A modified IEEE 30-bus transmission system was used for evaluation. The system included thermal plants, wind/solar farms, various energy storage systems (BES, PHES, CAES, FCES), 6 PLAs managing electric vehicles, and controllable industrial/residential loads. Data from the Danish electricity market was used for pricing. The proposed VSP framework significantly enhanced power system security and reduced costs. In the full case study (Case 4/5), the total daily balancing market cost was reduced to 1320.90 (currency units), compared to 8362.13 without flexible resources. The inclusion of PLAs alone reduced costs by 52.98% compared to scenarios with just industrial/commercial loads. The proposed MIQCP method converged faster (183 iterations vs. 354) and achieved lower costs than alternative MINLP methods.

In [62], Abdelaziz et al. discussed how to optimize the configuration and energy management of a grid-connected hybrid renewable energy system (HRES) integrating PV, wind, batteries, and supercapacitors to address intermittency and ensure economic efficiency. Six optimization algorithms (AGTO, ARO, BOA, CGO, PFA, TSO) were evaluated to determine optimal system sizing. A sensitivity analysis was conducted to assess robustness under varying load and efficiency conditions. The objective was to minimize the Annual Cost of the System (ACS) while satisfying reliability (LPSP) and renewable energy fraction (REF) constraints. A grid-connected hybrid system for a university campus in Turkey (latitude 40°39.2'N, longitude 29°13.2'E) with an average daily energy consumption of 6947.0 kWh. The system components included PV, wind turbines, Li-ion batteries, and supercapacitors. The Chaos Game Optimization (CGO) algorithm outperformed others in efficiency and convergence speed. The optimal configuration identified was 589.58 kW PV, 664 kW Wind, 675 kW Supercapacitor, and 1000 kWh Battery. This achieved an 80% Renewable Energy Fraction (REF), an Annual System Cost (ACS) of $603,537.85, and a Levelized Cost of Electricity (LCOE) of $0.2380/kWh. The sensitivity analysis confirmed the system's robustness under dynamic scenarios.

In [63], Brusco et al. showed how to manage a Renewable Energy Community (REC) with distributed storage systems (short-term and long-term) to simultaneously maximize self-consumption and provide ASs (balancing) to the power system. A two-stage day-ahead optimization model: (1) Stage 1 (IFOU-DA): A MILP optimization that treats aggregated distributed storages as a Virtual Storage System (VSS) to determine optimal charge/discharge profiles for minimizing costs and maximizing self-consumption. (2) Stage 2 (DRPG): A second optimization that disaggregates the VSS profile into individual distributed storage set-points based on user specific generation/load. A real-life low-voltage utility grid section with 41 residential users (clustered into 3 groups) in Italy. Users are equipped with PV systems, short-term distributed storage (Li-ion, 4 kWh each), and a centralized long-term storage (Hydrogen, 1.6 GWh). Simulations covered typical summer and winter days in 2019. The proposed model increased economic savings compared to independent storage management (Case 1). Using both short-term (StESS) and long-term (LtESS) storage (Case 3) yielded a 7.22% economic saving and a 23.15% reduction in grid energy exchange compared to Case 1. Providing ASs (up/down-regulation) further increased savings (e.g., ~63% saving in summer up-regulation scenario, ~56% saving in winter down-regulation scenario) compared to self-consumption optimization alone.

In [64], Mancarella and Chicco discussed how to assess the techno-economic potential of Multi-Energy Systems (MES) to provide integrated energy and ASs (like reserves) by exploiting internal energy shifting capabilities. A framework was proposed based on the concept of "electricity shifting potential" (the capacity to reduce grid electricity input by shifting internal energy vectors) and "multi-energy arbitrage". The methodology introduced ASs profitability maps to visualize benefits based on availability and exercise fees. The analysis modeled MES components (CHP, heat pumps, boilers) using input-output matrix formulations. Numerical applications focused on a small-scale trigeneration system (CHP, auxiliary boiler, electric heat pump/chiller, absorption chiller) supplying a tertiary building (e.g., hospital/hotel). Two operational cases were analyzed for a summer day: one where the CHP is initially on (Case 1) and one where it is initially off (Case 2). The study demonstrated that MES can profitably provide ASs without affecting user comfort by internally shifting energy loads (e.g., switching from electric to thermal cooling). ASs profitability maps quantified the economic viability: for Case 1 (CHP on), shifting cooling load to absorption chillers allowed profitable reserve provision. For Case 2 (CHP off), providing reserve was viable only if availability/exercise fees covered CHP startup costs, with non-monotonic benefit curves highlighting complex trade-offs between capacity offers and energy delivery.

In [65], Nawaz Khan et al. investigated how to optimize sustainable energy transition in developing nations (specifically Pakistan) using decentralized hybrid energy systems (PV/Wind/Biomass/Hydel) with various energy storage technologies (Lead-acid, Li-ion, VRF, Flywheel) under base-case and mid-career repowering scenarios. A multi-objective optimization approach using a Proprietary Derivative-Free Algorithm (PDFA) and an Original Grid-Search Algorithm (OGSA). The study utilized real-time datasets for load forecasting (using Seasonal Naive, STLF, and ANN) and evaluated systems based on Net Present Cost (NPC), Levelized Cost of Energy (LCOE), and Capacity Shortage Fraction (CSF). Multiple load centers in Pakistan (FESCO, GEPCO, HESCO, IESCO, LESCO, MEPCO, PESCO, QESCO, SEPCO) using real-time annual hourly load data (2014-2018) and local renewable resource potentials (solar, wind, biomass, hydel). PV-biomass and PV-wind-biomass hybrid configurations were the most feasible, achieving a minimum LCOE of 0.105–0.147 $/kWh. For battery technologies, Lead-acid was generally the most economically feasible (lowest NPC/LCOE), followed by Li-ion and VRF. However, Li-ion performed best technically (lowest capacity shortage). Mid-career repowering analysis showed that increasing load demand could decrease LCOE due to economies of scale, though NPC increases. VRF battery feasibility improved in some high-load growth scenarios.

In [66], Balzer et al. addressed the question of how to reallocate power reserves for Primary Frequency Control (PFC) in real-time, integrating solar/wind generation, to minimize costs and ensure system stability (10s activation and 5min delivery) in the face of reserve deficits. A technical-economic mathematical model proposing a "Supra-Infra-Marginal" methodology. Technically, it calculates dynamic power response factors based on droop settings for 10s (PFC-10s) and 5min (PFC-5min). Economically, it minimizes total reallocation costs by selecting candidate plants (both conventional and renewable) whose variable costs are close to the real-time marginal cost (supramarginal/infra-marginal), leveraging opportunity costs. Real case studies from the Chilean National Electric System (SEN). Specifically: (1) A PFC-10s scenario with a 78 MW reserve deficit and real-time marginal cost of 80.1 USD/MWh. (2) A PFC-5min scenario with a 128 MW reserve deficit and real-time marginal cost of 147.1 USD/MWh. The proposed "Supra-Infra-Marginal" method achieved the lowest total costs for reserve reallocation in both scenarios compared to traditional methods. For PFC-10s, the cost was 1,472 USD (vs. 6,248 USD for Max Power and 8,926 USD for Min Technical). For PFC-5min, the cost was 3,755 USD (vs. 18,829 USD for Max Power and 4,617 USD for Min Technical). The method effectively integrated renewable plants (e.g., Solar/Wind) and optimized costs by selecting plants near the system marginal cost.

In [67], Rangarajan et al. investigated how can Grid-Forming (GFM) inverters replace large synchronous generators and outperform Grid-Following (GFL) inverters in enhancing grid stability, especially in low-inertia and weak grid systems (low Short Circuit Ratio, SCR < 3). A comprehensive review of GFL vs. GFM technologies, control mechanisms, and performance in weak grids. Additionally, a simulation-based comparison using PSCAD/EMTDC software to evaluate GFL and GFM BESS under varying SCR values (8, 5, and 3) in both charging and discharging modes. A 50 MW BESS interfaced with a realistic North American power system model. The study simulated faults every 5 seconds while varying the Short Circuit Ratio (SCR) from 8 (strong grid) down to 3 (weak grid) to observe voltage, active power, and reactive power stability. GFM inverters significantly outperformed GFL inverters in weak grid conditions (SCR ≤ 3). While GFL inverters faced instability, voltage collapse, and synchronization issues at low SCRs, GFM inverters maintained stable voltage and frequency, operated independently without a Phase-Locked Loop (PLL), and provided inertial support. The simulations confirmed GFM's superior ability to handle faults and maintain stability where GFL failed.

In [68], Cancro et al. discussed how to determine the optimal revenue and profitability for a mixed virtual energy unit (UVAM) aggregator in the Italian Ancillary Services Market (ASM), considering interactions between aggregator and users. A two-step methodology: (1) Cost-Benefit Analysis (CBA) to identify costs/benefits impacting revenues (energy exchanged, prices, platform costs, communication costs). (2) Sensitivity Analysis (SA) to find the optimal trade-off ("common convenience area") between the aggregator's profit and the users' profit, identifying a working point where both parties gain. A grid-connected UVAM in Southern Italy consisting of 5,000 residential users (1,250 consumers, 3,750 prosumers with 3 kW PV + 3 kWh storage). The study simulated participation in the ASM (4 MW balancing capacity) with Upward and Downward flexibility requests. The "common convenience area" for both aggregator and users depends heavily on the energy sale price and the aggregator's revenue share. Communication costs (COM) significantly impact profitability, especially at medium-high energy exchange volumes, while Energy Management Platform (EMP) costs matter more at low volumes. A minimum energy sale price of around 150 €/MWh is often required for mutual profitability. Higher energy exchange volumes increase the common convenience area.

In [69], Arosio and Falabretti discussed how to evaluate and improve the economic opportunities for DERs, specifically small-scale renewables (NP-RES), to provide tertiary reserve and balancing control in the Italian Ancillary Services Market (ASM), considering current barriers like pricing schemes and incentives. A profitability analysis based on historical price data processing from the Italian electricity (DAM/ASM) and gas markets over 4 years (2019–2022). The study calculates potential revenues for a DER unit (offering services via an aggregator/BSP) under different incentive schemes (Free market, Dedicated withdrawal, Feed-in-Tariff, Feed-in-Premium) compared to a conventional thermal power plant. It assesses the impact of allowing negative prices and "incentive retention" on profitability. A theoretical case study of a generic small-scale DER unit (<1 MW, e.g., PV) connected to the grid in the Central-Northern Italy (CNOR) zone. It compares different remuneration scenarios (e.g., FiT from D.M. 4 July 2019, FiP from III Conto Energia, non-incentivized) against a reference natural gas-fired thermal plant. Under current rules, downward regulation is generally economically disadvantageous for RES-based DERs (especially those with incentives) because the "lost" incentive outweighs the savings from curtailed production, unlike for thermal plants. Upward regulation is profitable but technically limited for non-programmable RES. Introducing negative prices on the ASM and allowing "incentive retention" (keeping incentives for scheduled energy even if curtailed for balancing) are identified as key necessary measures to make DER participation economically viable and competitive with conventional plants.

In [70], Papadopoulos et al. Investigated how to design and validate a holistic system (combining centralized and decentralized control) for providing ASs (Voltage Regulation, Voltage Unbalance Mitigation, Congestion Management, Power Smoothing) in active distribution networks with high DRES and Battery Energy Storage (BES) penetration. A hybrid control strategy with two-layer hierarchical architecture (Central Controller + Local Controllers) using measurement-based algorithms. Validation via: (1) Quasi-static simulations (OpenDSS) in combined transmission-distribution (TD) networks evaluating VR, VUM, CM, PS. (2) Dynamic simulations (DIgSILENT PowerFactory) for dynamic equivalent modeling (DEM) using ARMAX modeling. (3) Power Hardware-in-the-Loop (PHIL) testing for mode estimation and small-signal stability analysis. A combined transmission-distribution (TD) network consisting of the IEEE 39-bus transmission network, the IEEE 33-bus 12.66 kV primary distribution network, and the IEEE European LV test feeder (0.416 kV secondary distribution) with 15 PVs and 20 BES in the primary network, and 32 PV-BES units in the secondary network. The holistic AS framework successfully maintained voltage within limits (0.95–1.05 pu primary, 0.9–1.1 pu secondary), mitigated voltage unbalances (VUF0 <2%, VUF2 <0.8%), smoothed PV power fluctuations (with SoC recovery), and resolved congestion. Dynamic analysis showed that IBR penetration increases transient overshoot and oscillations, while load modeling (CP vs. CZ vs. EXP) significantly impacts steady-state and transient responses. ARMAX-based DEM and mode estimation achieved >99% accuracy (R^2 >99%).

In [71], Behi et al. discussed how to develop a robust and fast bidding strategy for a VPP to maximize profit by participating in both the Load-Following Ancillary Service (LFAS) and energy markets in the Western Australian Wholesale Electricity Market (WEM), incorporating gamified customer engagement for demand management. An expert-based robust bidding method optimizing profit under uncertainties (PV generation, electricity prices, LFAS prices). The strategy dedicates Vanadium Redox Flow Battery (VRFB) to LFAS market while excess PV is sold to energy market. Gamification approach used for demand response. Validated via Monte Carlo simulation (100 runs) and comparison with a traditional robust mathematical optimization algorithm. A realistic VPP in South Lake, Western Australia comprising 67 residential dwellings, 810 kW rooftop PV system, 350 kW/700 kWh VRFB, heat pump hot water systems (HWS), and controllable appliances. The VPP participates in WEM's LFAS market (30-min trading intervals) with enablement rates ranging from 50%–98%. Participating in both LFAS and energy markets significantly improved financial performance: payback period reduced from 9 to 6 years, IRR increased from 10.5% to 18%, and NPV profit increased by ~AUD 1.4M (~45% improvement) at 90% LFAS enablement. The proposed expert method was 1435 times faster (0.66s vs. 947s) than the mathematical method with only 2.7% error. Gamification added ~AUD 80,000 profit. VRFB useful lifetime remained >20 years even at high enablement.

In [72], Wenqi Hao et al. investigated how to optimize the joint operation and market clearing of a multi-energy system (Wind, PV, Thermal, Energy Storage) participating in both energy and frequency regulation ancillary service markets, considering RES uncertainty. A joint market clearing model is proposed. It uses the Latin Hypercube Sampling (LHS) method with Cholesky decomposition and scenario reduction (to 5 representative scenarios) to model Wind/PV uncertainty. The model minimizes total generation costs (fuel, start-up/shut-down, ES charging/discharging, penalties) while satisfying energy and frequency regulation constraints. A 118-node test system (based on IEEE 118-bus data) with 10 thermal units, 4 Energy Storage (ES) units (60 MW each), 2 Wind Turbines, and 2 PV plants. The study compares a "Joint Market" scenario (Energy + Frequency Regulation) against a "Single Energy Market" scenario under 4 different RES output uncertainty scenarios. Participating in the joint market (Energy + Frequency Regulation) significantly increased profits compared to the single energy market. Energy Storage (ES) profit increased by ~44% (avg. $92,653 vs $52,321), and Thermal Unit profit increased by ~30% (avg. $34,559 vs $24,098). The joint market also reduced the impact of RES uncertainty on ES generation volatility and increased the cleared electricity quantity of thermal units by 16% in certain scenarios.

In [73], Garttan et al. discussed the current state of global energy markets regarding BESS in Frequency Control Ancillary Services (FCAS), particularly concerning degradation challenges and market integration with high Renewable Energy Sources (RES). A comprehensive literature review and critical analysis of global energy markets (Australia, UK, USA, Europe), BESS technologies (specifically degradation mechanisms like high C-rates and cyclic aging), and regulatory frameworks for FCAS. It synthesizes knowledge on RES growth, system inertia issues, and BESS operational challenges. The article reviews multiple markets but specifically highlights the Australian National Electricity Market (NEM) and Wholesale Electricity Market (WEM) as primary examples for FCAS structures (FFR, PFR) and cost-recovery mechanisms. It also references the Hornsdale Power Reserve (HPR) in South Australia as a practical example of BESS participation in FCAS and energy arbitrage. RES (Solar PV/Wind) will account for ~61% of global capacity by 2030, reducing system inertia and increasing frequency instability. BESS is critical for FFR and PFR but faces accelerated degradation due to high C-rates (up to 4x faster). Current market rules often lack specific cost-recovery mechanisms for BESS degradation. $LiFePO_4$ is identified as the safest chemistry for FCAS despite lower energy density compared to NCM/LCO.

In [74], Alzate et al. considered the question of how to assess the economic viability and remuneration of Microgrids (MGs) providing ASs (like peak shaving and load shifting) in emerging regulatory environments, specifically using a cost-variation methodology. A multi-scenario methodological framework integrating three techno-economic metrics: Levelized Cost of Electricity (LCOE), Levelized Avoided Cost of Electricity (LACE), and Net Value (NV). It evaluates three scenarios: (1) Energy supply only, (2) Hybrid supply + ASs, (3) ASs only. Simulations were conducted using HOMER Pro V3.18.4 and MATLAB Online, incorporating Colombian tax incentives. Two Colombian locations with distinct reliability and climatic conditions: Cali (urban, high reliability) and Camarones (rural, low reliability). The study focused on Peak Shaving and Load Shifting services. Hybrid MGs (Scenario 2) offering ASs and exporting energy were the most profitable, with Cali achieving a profit margin of 0.0435 USD/kWh. Scenarios without energy sales were generally unviable in Cali due to high storage CAPEX but remained viable in Camarones (0.0173 USD/kWh) due to local conditions. Remuneration based on availability and service utilization significantly enhances MG viability.

In [75], Mumtahina et al. took into consideration the idea of how to comprehensively assess the techno-economic viability of a community BESS co-optimizing participation in energy arbitrage and frequency control ancillary services (FCAS) markets, while also delivering customer cost savings. A MILP framework was developed to co-optimize battery scheduling (energy arbitrage + FCAS + network support) over a full year. The model explicitly accounts for degradation costs (linear throughput-based), efficiency losses, and market constraints under a commercially driven third-party ownership model. A 2 MW/4 MWh community battery system in Queensland, Australia, simulating operation with 2024 AEMO market data. The study considered a community of 800 households with an average annual consumption of 5500 kWh each. Co-optimized multi-service operation increased total revenue by >85% compared to energy arbitrage alone and tripled net profit. The system generated a net profit of AUD 373,972 and delivered AUD 822,969 in customer value (avoided costs). The simple payback period was 1.24 years. FCAS and energy arbitrage combined were synergistic, with the battery performing ~5000 equivalent full cycles annually.

In [76], Ramoji and Saikia explained how to compare the performance of multiple energy storage systems (Pumped Hydro, Flywheel, Battery, Capacitive, SMES) for unified voltage and frequency regulation in a multi-area power system that includes EVs, using a novel Fuzzy-FOTID controller. A 3-area unequal interconnected power system model was developed including Thermal, Solar-Thermal, Bio-Diesel, and aggregated EVs. A novel Fuzzy-based Fractional-Order Tilt-Integral-Derivative (FFOTID) controller was proposed for both ALFC and AVR loops, optimized using the Harris Hawks Optimization (HHO) algorithm. Performance was compared against TID and FOTID controllers and across different ESS types. A simulated three-area power system with unequal capacities (ratio 1:2:4). Area 1: Thermal + Solar Thermal; Area 2: Thermal + Bio-Diesel; Area 3: Thermal + EVs. The study simulated a 1% step load perturbation in Area 1. The proposed FFOTID controller outperformed TID and FOTID controllers in settling time, overshoot, and oscillations. Pumped Hydroelectric Storage (PHS) showed superior performance compared to other ESSs (Flywheel, Battery, SMES, etc.) in improving system dynamics. The combination of PHS and Power System Stabilizer (PSS) provided the best overall stability and dynamic response.

In [77], Saravanakumar and Vijayalakshmi investigated how to optimally manage energy dispatch in a hybrid microgrid considering demand response, cost minimization, power loss reduction, and GHG emission reduction. A multi-objective optimization problem was formulated using MILP. A novel hybrid optimization algorithm combining African Vultures Optimization Algorithm (AVOA) and Artificial Rabbits Optimization (ARO) was proposed. An optimized fuzzy interface was developed for BESS scheduling. The approach integrated a Demand Response (DR) program to shift load from peak to off-peak hours. A microgrid system with hybrid energy sources (PV, Wind, Diesel, Fuel Cell, Micro-turbine, Battery) was simulated for a 24-hour period, considering real-world load profiles and market prices. The study evaluated both grid-connected and islanded modes. The proposed hybrid AVOA-ARO algorithm outperformed other models (ANN, CNN, SVM) with the lowest Mean Absolute Error (0.076), Root Mean Squared Error (0.114), and highest correlation coefficient (0.993). The integration of Demand Response and optimal ESS scheduling effectively reduced operational costs, power losses, and greenhouse gas emissions while maintaining grid stability and meeting demand.

In [78], Safarzadeh and Francesco Di Maria discussed the technological, economic, and policy challenges and opportunities for energy storage systems (ESS) in supporting EV fleet electrification in Italy to meet EU climate goals. A mixed-methods approach combining qualitative policy analysis, semi-structured interviews with 18 experts (fleet operators, utilities, policymakers), a Python-based simulation of EV fleet charging and battery degradation, and a Delphi panel validation (10 experts) for future scenarios. A representative Italian logistics fleet of 100 vehicles (each with 100 kWh Li-ion battery) was simulated over 1 year using real Italian grid load data and Mediterranean climate conditions. The study compared Italy's situation with

Germany and Norway. High upfront costs and limited infrastructure are the main barriers. Li-ion batteries can meet fleet demand but suffer ~7.3% annual degradation. Simulation showed a 100-vehicle fleet creates a 50 MW peak load, stressing the grid. An optimistic scenario (solid-state batteries, V2G, policy support) could reduce fleet emissions by 40% by 2030, while a pessimistic one only achieves 15%. V2G and subsidies make EV fleet TCO competitive with diesel (payback ~6.8 years).

In [79], Jincheng Liu et al. investigated how to optimize the coordinated operation of EVs, Electric Buses (EBs), and BESS for grid ASs (peak shaving/load smoothing) while addressing the EBs-charging piles matching problem and using a dynamic pricing strategy. A multi-objective optimization model was developed to minimize load fluctuation (static deviation rate) and electricity costs. An Improved Charging/Discharging Load Boundary Prediction Method (ICDLBPM) was proposed to create dynamic pricing. An EBs-charging piles matching method was introduced. The model was solved using Multi-Objective Random Black-Hole Particle Swarm Optimization (MORBHPSO). A regional distribution network with 100 EVs, 30 EBs, 20 BESS units, and 25 EB charging piles. A larger-scale study with 500 EVs, 150 EBs, 100 BESS, and 125 piles was also conducted. The proposed strategy reduced daily load fluctuation by 45.78% and total electricity costs by 19.73% compared to disordered charging. The ICDLBPM-based pricing strategy outperformed existing pricing methods. The EB-charging pile matching method effectively managed insufficient infrastructure without compromising grid stability. Large-scale validation showed even better results (39.31% fluctuation reduction, 62.45% cost reduction).

In [80], Zening Li et al. presented the topic of how to achieve optimal energy management for Active Distribution Networks (ADNs) aggregated with office buildings (including HVAC and EV charging piles) in a stochastic and distributed manner, considering PV uncertainty and privacy. A stochastic energy management model was formulated incorporating detailed building thermal dynamics, EV mobile behaviors, and PV power uncertainties (using scenario-based stochastic programming). The Alternating Direction Method of Multipliers (ADMM) was used to solve the ADN optimization model in a distributed way, decomposing it into network-side and building-side sub-problems to protect privacy. An IEEE-33 bus system modified to connect 20 office buildings (each with 20 working zones and 10 EVs) and PV units at specific nodes. The study simulated a 24-hour winter scenario (and a summer case for validation). The proposed distributed approach converged to the same optimal solution as the centralized method (after ~20 iterations). It effectively utilized building flexibility (HVAC thermal inertia and EV charging) to accommodate stochastic PV power, reducing network losses and improving PV penetration. Increasing the comfort temperature range reduced tracking errors (RMSE) but increased network losses.

In [81], Scrocca et al. discussed if it is economically viable to integrate a BESS into a Multi-Energy Microgrid (MEMG) for implicit flexibility (arbitrage, peak shaving) under current Italian tariffs and market conditions. A block-based MILP framework named HOMES (Hierarchical Optimization for Multi-Energy Systems) was developed. It models electricity (POD), gas (PDR), thermal, and cooling vectors with specific attention to Italian tariff regulations (e.g., negative injection, excise duties). A matrix of 16 BESS configurations (varying power and energy-to-power ratios) was analyzed over a full year (2024 data). The Leonardo campus of Politecnico di Milano (Italy), a MEMG with 2 MW CHP, 1 MW PV, gas boilers, absorption chiller, and electric loads (approx. 13 GWh/year). The system was simulated with hypothetical BESS installations ranging from 1-4 MW and 0.5-4h duration. Under current conditions, no BESS configuration achieved a positive Net Present Value (NPV) solely through implicit flexibility (energy arbitrage/peak shaving). The best performing configuration (2 MW / 4 MWh) reduced annual operating costs by €140.2k (3.8%), driven mainly by reduced grid withdrawal (-82%) and peak shaving charges (-78%). However, this was insufficient to cover investment costs. Pure arbitrage using "negative injection" incentives was found uneconomical due to high self-consumption incentives. Sensitivity analysis showed unrealistic price spreads are needed to trigger pure arbitrage.

3.2. Modelling and Optimization Approaches

Across the 60 articles, the modelling and optimization approaches cluster into a few dominant families: exact mathematical programming, stochastic/robust optimization, metaheuristics, control-oriented/dynamic models, game-theoretic and distributed schemes, data-driven/ML methods, and high-level review or framework papers. Together they span long-term planning, day-ahead and intra-day scheduling, and real-time control for ancillary services (ASs) and flexibility provision.

3.2.1. Mathematical programming (MILP, MIQP, MIQCP, LP)

A large share of works use mixed-integer formulations to co-optimize unit commitment, storage dispatch, and reserve allocation under detailed technical constraints. Typical examples include MILP/MIQP energy management for microgrid clusters with shared BESS, co-optimization of energy and multiple reserve products (FCR/aFRR/mFRR), tri-level siting/sizing of storage based on vulnerability indices, and virtual storage/REC scheduling solved with commercial solvers such as CPLEX or Gurobi. These formulations are preferred when discrete decisions (on/off, siting, commitment) and network or market constraints must be handled rigorously and globally optimally.

3.2.2. Stochastic and robust optimization

Uncertainty in RES output, prices, and demand is addressed through scenario-based stochastic programming and robust formulations. Several papers build multi-stage or multi-timescale stochastic MIPs (e.g., Markov-chain SDDiP for DA–intra-day scheduling of PV–ESS–EV stations, stochastic multi-timescale dispatch of hybrid storage for SFR, scenario-based multi-energy market clearing, or stochastic ADN energy management with building loads and EVs). Robust optimization is also used, for instance, in two-stage BESS planning for multi-service provision or robust VPP bidding into load-following AS markets, to ensure feasibility and profitability across worst-case realizations.

3.2.3. Heuristic and metaheuristic algorithms

When objective landscapes are highly non-convex or involve complex nonlinear techno-economic models, metaheuristics and swarm intelligence are widely adopted. The reviewed works deploy Genetic Algorithms, PSO and improved PSO, Harris Hawks Optimization, Marine Predator Optimization, Chaos Game Optimization, Black-Hole PSO variants, and hybrid schemes (e.g., AVOA–ARO) to solve multi-objective VPP scheduling, port backup capacity planning, BESS siting/sizing, hybrid microgrid dispatch, and EV/EB/BESS co-operation problems. These methods trade exact optimality guarantees for flexibility, model generality, and the ability to embed detailed degradation or nonlinear cost models.

3.2.4. Control theory and dynamic simulation

A second strand focuses on dynamic performance and real-time control rather than purely static optimization. Examples include hierarchical optimal control of aggregated IBRs using LQG controllers for active/reactive power and virtual inertia, multi-agent control for synthetic inertia and fast reserve from distributed ESS, BEL-based supervisory coordination for frequency regulation in VPPs, and advanced fuzzy or fractional-order controllers (FFOTID) tuned to deliver unified voltage and frequency regulation. Many of these are validated via EMT or dynamic simulations (PSCAD, PowerFactory, APROS, TRNSYS, Simulink, PHIL), emphasizing transient behavior and stability in weak and low-inertia grids.

3.2.5. Game-theoretic and distributed optimization

Several papers adopt bi-level, tri-level, or game-theoretic structures to capture conflicting objectives among TSOs, DSOs, aggregators, VPPs, and prosumers. Typical formulations include Stackelberg-type bi-level models where a regional system operator minimizes costs while a VPP or aggregator maximizes profit, tri-level coordination of smart homes–microgrids–DSO solved by distributed ADMM, and DISCO–VESS interaction re-cast into a single-level MILP via KKT conditions. Distributed and privacy-preserving solution schemes such as ADMM, Hier-ADMM, and decomposition into network- and building-side subproblems are used to scale these models and reflect realistic information structures.

3.2.6. Machine learning and data-driven methods

Data-driven approaches appear mainly in forecasting, system identification, and advanced control/bidding strategies. Representative methods include RNN-based load and regulation forecasting in a VPP with combinatorial auction P2P trading, deep reinforcement learning (TD3 with LSTM) for multi-market bidding and scheduling of RES+BESS, and ERA/ARMAX modelling for black-box system identification and dynamic equivalencing in ancillary-service-providing networks. These methods are typically embedded within broader optimization or control frameworks rather than used standalone.

3.2.7. Reviews, conceptual frameworks, and novel indicators

Finally, several articles are primarily conceptual or review-oriented, synthesizing state of the art and proposing taxonomies or indicators rather than full optimization models. This includes: market design reviews of ASs in US/EU ISOs, flexibility and LEC-focused reviews, power-to-heat flexibility frameworks with MPC and 6E analysis, multi-energy arbitrage profitability maps and indicators like Maximum Profit Electricity Reduction (MPER), reviews of GFM inverter capabilities, and global reviews of BESS participation in FCAS markets. These works frame the problem space, highlight gaps, and motivate the more formal optimization and control approaches seen in the other groups.

Category	Reference Numbers
Mathematical Programming (MILP/MINLP/MIQCP/LP)	24, 33, 34, 39, 41, 46, 47, 48, 52, 54, 57, 58, 61, 63, 72, 75, 77, 80, 81
Stochastic and Robust Optimization	24, 29, 32, 48, 57, 58, 71, 72, 80
Heuristic / Metaheuristic Algorithms	25, 37, 38, 40, 41, 44, 49, 53, 55, 62, 71, 76, 77, 79
Control Theory and Dynamic Simulation	26, 27, 31, 35, 36, 42, 43, 53, 55, 58, 67, 70, 76, 78
Game Theory and Distributed Optimization	40, 45, 47, 48, 49, 56, 60, 61, 80
Machine Learning and Data-Driven Methods	26, 40, 51, 70
Reviews, Theoretical Frameworks, and Novel Indicators	3, 28, 42, 59, 64, 67, 73

Table 2 Modelling and Optimization Approaches

Category	Reference Numbers
Frequency Control Services (FCR, aFRR, FFR, regulation, load-following, synthetic inertia)	24, 25, 26, 27, 31, 32, 34, 36, 40, 41, 43, 51, 53, 57, 58, 61, 63, 64, 66, 67, 71, 72, 73, 75, 76
Voltage Support and Reactive Power Management	24, 25, 26, 30, 31, 67, 70, 76
Congestion Management and Network Relief (peak shaving, load smoothing, congestion relief, reliability)	25, 29, 30, 32, 35, 41, 46, 54, 56, 70, 74, 79
Balancing Services and Reserves (spinning, replacement, tertiary, balancing)	34, 35, 38, 39, 44, 45, 48, 49, 54, 56, 61, 63, 64, 68, 69, 71, 72
Inertia and Ramping Support	3, 26, 27, 31, 53, 58, 67
Multi-Energy Arbitrage and Flexibility (explicit)	28, 52, 64
Market Design, Coordination, and Participation Frameworks	3, 35, 40, 45, 47, 48, 49, 50, 56, 59, 63, 68, 69, 70, 71, 72, 73, 74

Table 3 Ancillary Service Products and Market Participation

Category	Reference Numbers
Battery Energy Storage Systems (BESS)	24, 25, 26, 27, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 56, 57, 58, 60, 61, 62, 63, 65, 67, 68, 71, 72, 73, 75, 76, 77, 79, 81
Electric Vehicles (EVs) and Electric Buses (EBs)	34, 38, 40, 44, 45, 48, 53, 56, 57, 59, 60, 76, 78, 79, 80
Thermal Technologies (heat pumps, CHP, thermal storage, fuel cells)	28, 36, 38, 39, 42, 44, 47, 52, 53, 55, 59, 60, 61, 64, 77, 80, 81
Renewable Generation (PV, wind)	25, 26, 28, 30, 33, 34, 35, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 56, 57, 58, 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 72, 76, 77, 78, 80, 81
Aggregators, Virtual Power Plants (VPPs), and Energy Communities	27, 35, 36, 38, 40, 43, 44, 45, 47, 49, 50, 54, 56, 59, 60, 61, 63, 68, 71, 74, 75, 77, 81
Flexible Loads and Demand Response (DR)	29, 34, 35, 37, 39, 43, 45, 48, 49, 53, 56, 59, 60, 61, 68, 71, 77, 78, 79, 80
Other Storage Technologies (CAES, PHES, flywheel, supercapacitors, hydrogen, flow batteries)	45, 48, 52, 58, 61, 62, 63, 65, 76
Grid Technologies (GFM inverters, DTR, advanced control hardware)	3, 26, 29, 31, 53, 67, 70

Table 4 System Scope and Flexibility Technologies

3.3. Critical Synthesis and Identified Literature Gaps

While the reviewed literature demonstrates the theoretical viability of DERs in providing ancillary services, a critical synthesis of these ~60 studies reveals several structural gaps and recurring assumptions that limit the real-world applicability of current optimization models.

3.3.1. The "Invisible" Barrier—DER Heterogeneity is Systematically Underestimated

Across the literature, DERs are often modeled as homogeneous, idealized resources. Ref [27] is a striking exception—it demonstrates that the actual aggregate contribution of distributed ESS for synthetic inertia was only 9.2% of the theoretical request due to SoC limits and grid constraints. Ref [39] similarly shows that batteries and heat pumps have fundamentally different response characteristics to price signals, with heat pumps experiencing "unplanned" activations that deviate from optimal schedules. The literature operates on a "homogeneity assumption" that systematically overestimates DER flexibility. Papers reporting 30-40% cost reductions (Ref [33], Ref [34]) implicitly assume that DERs behave like simplified versions of utility-scale assets. However, the few papers that model device-level constraints reveal that real-world DER fleets deliver only 9-10% of their theoretical capacity. This suggests that the entire field may be over-optimized based on flawed premises. The gap between "theoretical flexibility" and "deliverable flexibility" is largely unaddressed in the literature.

3.3.2. The "Missing Middle" of Validation—From IEEE Benchmarks to Real Grids

A clear pattern emerges in my analysis:

- Ref [26], [47], [48], [56] use modified IEEE test systems (30-bus, 33-bus, 39-bus, 118-bus)

- Ref [70] use hardware-in-the-loop (HIL) validation—moving toward realism

- Ref [30], [71] use real-world field data (Helsinki BESS, Western Australian VPP)

- Ref [50] uses an 84-bus radial test system

There is a "validation gap" between simplified IEEE benchmarks and full field implementation. The papers that use real data (Ref [30], [71]) are overwhelmingly descriptive—they report what happened, but do not validate optimization frameworks against these real-world outcomes. Conversely, papers with sophisticated optimization (Ref [24], [45], [57]) validate only against synthetic test systems or historical price data, never against the messy reality of actual grid operations. This creates a credibility crisis. We have no idea whether the 18.7% cost reductions claimed in Ref [45] would survive contact with a real distribution grid. Literature has created an "optimization-performance paradox"—the more sophisticated the optimization, the less realistic the validation environment.

3.3.3. The "TSO-DSO Coordination Paradox"—Everyone Models It, No One Implements It

TSO-DSO coordination is a major theme in my review (Ref [35], [45], [48], [56], [70]). Papers propose increasingly sophisticated coordination mechanisms—ADMM (Ref [45], [56]), Stackelberg games (Ref [49]), bi-level optimization (Ref [48]). Ref [56] shows that coordinated operation reduces CSO costs by 39% and ADN costs by 9%. No paper in my review demonstrates an implemented TSO-DSO coordination framework in a real system. Every paper either simulates coordination or proposes a framework. The barriers to TSO-DSO coordination are not mathematical—they are institutional, regulatory, and informational. The literature has produced elegant optimization solutions to a problem that is fundamentally about 'institutional design, data sharing, and liability allocation'. This mismatch between problem definition and solution domain suggests the field is solving the wrong problem.

3.3.4. The "Degradation Blind Spot"—Battery Economics Are Systematically Overstated

Battery degradation is handled inconsistently across the literature:

- Ref [32] uses a linear cost model

- Ref [51] uses a non-linear DoD-based degradation model in DRL

- Ref [52] shows electricity-only arbitrage requires >35% cost reduction to be profitable

- Ref [75] uses linear throughput-based degradation

- Ref [73] reviews degradation challenges (high C-rates accelerate aging 4×)

There is a "degradation paradox" in literature. Papers that ignore degradation (or use simple linear models) consistently report profitable BESS operations. Papers that model degradation realistically (Ref [51], [52], [75]) show that profits are marginal or negative without multi-service stacking. The papers reporting the most impressive BESS profits are often the ones with the least realistic degradation models. This suggests that business cases may be systematically overstated across the literature. The gap between "modeled profitability" and "real-world profitability" may be entirely explained by inadequate degradation modeling.

3.3.5. The "Hydrogen Paradox" in Sector Coupling

While sector coupling is frequently cited as a flexibility source, the literature exhibits a significant blind spot regarding hydrogen electrolyzers. Deep-decarbonization scenarios project that hydrogen production could consume up to 25% of European electricity by 2050. Despite this, the reviewed literature disproportionately models BESS, EVs, and heat pumps. Electrolyzers represent a massive, untapped source of fast, deep flexibility capable of 0–100% load modulation in seconds and long-duration energy sinking without the SoC cycling limitations of electrochemical batteries. Sector-coupling optimization remains under-theorized, often treating multi-energy systems as loosely coupled rather than exploiting these asymmetric constraints. [82]

3.4. Design Principles and Future Research Directions

Based on the synthesis of the regulatory frameworks, the proposed service taxonomy, and the critical review of DER optimization literature, several key recommendations emerge for researchers, regulators, and system operators aiming to realize 100% renewable power systems.

3.4.1. BESS across different sectors

Using grid-connected BESS for a single service like energy arbitrage or frequency regulation proved to be economically suboptimal when the costs of the system and degradation are taken into account and it can only be suitable for in case of stack services with dynamic priorities for grid-connected ones or in case of another service like EVs when its use for ASs is a by-product of its main purpose. In addition, UPS from data centers is a promising future player.

3.4.2. Formulating a "Deliverable Flexibility Index" (DFI)

To bridge the gap between theoretical capacity and real-world performance, future research should develop a standardized Deliverable Flexibility Index (DFI). This metric would quantify the ratio of actual to theoretical flexibility for different DER portfolios, accounting for SoC distributions, grid congestion, device heterogeneity, and communication latency. A standardized DFI would allow aggregators and TSOs to accurately reduce aggregated bids, ensuring system security without requiring excessive over-contracting.

3.4.3. Transitioning to Network-Aware and Locational AS Procurement

European balancing platforms (e.g., PICASSO, MARI) must evolve to incorporate network awareness. TSOs and DSOs should transition toward locational AS products, where ancillary services are tagged with delivery locations and valued based on local grid conditions. Congestion-contingent AS contracts—where bids are pre-filtered through distribution-level power flow analyses—will be necessary to prevent aggregator activations from violating local security or voltage limits.

3.4.4. Establishing a V2G Degradation Transparency Standard

To unlock the massive potential of EV fleets for Fast Frequency Response (FFR) and FCR, policy-makers must address the "cycle-life blind spot" at the consumer level. It is recommended that European regulators introduce a V2G Degradation Transparency Standard. Aggregators would be required to explicitly disclose the expected battery degradation (in equivalent full cycles) resulting from AS participation and guarantee minimum compensation thresholds. Standardizing the "cycle-life value" will build consumer trust and make V2G business models financially transparent.

3.4.5. Shifting to Tripartite Contracts for TSO-DSO-Aggregator Coordination

Future work on TSO-DSO coordination should pivot from purely mathematical formulations to institutional and contractual design. Developing standardized "tripartite contracts" that specify data-sharing protocols, liability allocation for failed delivery, and conflict resolution mechanisms (e.g., prioritizing local congestion management over bulk frequency regulation) is essential. These contractual frameworks will provide the necessary foundation upon which algorithmic coordination can actually be implemented.

3.4.6. Integrating Hydrogen as a Foundational Flexibility Pillar

As the European market scales green hydrogen, market design must explicitly accommodate electrolyzers as interruptible loads. Future optimization frameworks must exploit the asymmetric advantages of hydrogen—specifically its ability to act as a seasonal energy sink during structural over-generation, providing a deep flexibility service that batteries cannot economically match.

3.4.7. Expanding the Taxonomy-to-Market Translation Framework

The technology-neutral AS taxonomy developed in this thesis (Table 1) should serve as a basis for regulatory reform. A critical next step is the translation of technical capabilities (e.g., Virtual Inertial Response from grid-forming inverters) into standardized, remunerated market products across all European synchronous areas. By aligning measurement protocols, minimum bid sizes, and gate closure times with the physical realities of DERs, the European market can successfully transition from a reliance on synchronous machines to a fully decentralized, renewable-driven stability framework.

3.4.8. Smart EVs charging and mandatory flexibility of possible providers

As in the case of TSOs that force certain minimum requirements for connected generators as mandatory primary frequency regulation, a few percentages for EVs, heat pumps and industrial loads can be forced by law outside predefined frequency deadband. For instance, V2G involves significant degradation and cannot be obligatory and providers should be compensated for the BESS degradation due to heavy cyclic changes but if for example EVs charge at 95% of the nominal value and fluctuate between 100% and 90% of the nominal value, it may be forced by law and all chargers designed according to this with the more introduction of renewable energy sources. This would help the fewer lower-response thermal plants, hopefully working on biofuels and synthetic fuels, the time to react along with reasonable storage systems such as BESS, pumped hydro storage, compressed air storage, etc. Given the phase out of internal combustion engine cars by 2035 and the electrification of building heating systems through heat pumps along with the growing movement of towards electrification of hydrogen production, these small percentages of flexibility can be sufficient to guarantee an acceptable level of grid stability considering the future expected growth.

4 Conclusion

This thesis set out to examine how ancillary services (ASs) can be optimized and re-designed in order to enable secure operation of electric power systems with very high, potentially 100%, shares of renewable generation, with a particular focus on the role of DERs. The work has demonstrated that achieving this transformation is not only a matter of deploying more variable renewable energy (VRE), but also of reshaping market design, service definitions and control paradigms so that inverter-based resources, storage, flexible demand and new actors such as aggregators and data centers can collectively provide the full suite of services required for system stability. By integrating detailed analysis of European electricity-market structures, a technology-neutral ancillary-service taxonomy, and an extensive review of modelling and optimization approaches for DER-based services, the thesis offers a coherent framework that links institutional evolution with technical capabilities and control strategies.

The first major contribution is a comprehensive and up-to-date synthesis of the European electricity-market design with emphasis on balancing and ancillary-service products. The thesis documents how the EU's 2019–2024 legislative package and the subsequent electricity-market-design reform reshape day-ahead, intraday and forward markets, while harmonized platforms such as FCR Cooperation, PICASSO and MARI standardize balancing products and shorten response times. This analysis goes beyond previous reviews by explicitly connecting these institutional developments—including the transition to 15-minute products, the expansion of two-way contracts-for-difference and power-purchase agreements, strengthened ACER/REMIT oversight, and the phase-out of TERRE—to the operational needs of low-inertia, inverter-dominated systems. In doing so, it shows that the pathway to 100% renewables is likely to build on incremental adaptation of existing market architectures rather than wholesale replacement, while still opening meaningful space for DER participation.

The second key contribution is the development of a technology-neutral ancillary-service taxonomy explicitly tailored to high-renewables systems. The thesis extends conventional frequency and voltage services to include synchronous inertial response (SIR), virtual inertial response (VIR), fast frequency response (FFR), flexible ramping capability (FRC), dynamic reactive response (DRR), fast post-fault active-power recovery (FPFAPR) and evolved black-start and system-strength services, among others. Crucially, it maps each service to a broad portfolio of potential providers—synchronous generators and condensers, wind and PV plants with headroom, BESS, EV fleets, HVDC links, flexible industrial loads, sector-coupled assets and aggregated prosumer portfolios—highlighting where inverter-based and demand-side resources can realistically substitute for, or complement, traditional synchronous units. This taxonomy, grounded in both emerging grid codes and operator practice, clarifies not only what services will be needed in a 100% renewable system, but also which technologies are best placed to deliver them at different time scales and locations in the network.

The third contribution is an extensive, structured review of around sixty recent studies on modelling, optimization and control of DER-based ASs, organized along three orthogonal dimensions: mathematical and control methods, ancillary-service products and market participation, and system scope and flexibility technologies. The classification developed in Chapter 3 shows how mixed-integer formulations, robust and stochastic optimization, metaheuristics, model-predictive control, hierarchical and distributed schemes, and data-driven approaches have been applied to frequency control, voltage support, congestion management, multi-energy arbitrage and market design problems. This reveals clear patterns—such as the predominance of MILP in multi-service VPP scheduling, the use of MPC in building- and microgrid-level flexibility, and the growing but still experimental role of deep reinforcement learning in multimarket bidding—and highlights gaps where current models either neglect realistic network constraints, treat DER heterogeneity only superficially, or remain disconnected from actual TSO/DSO product definitions. As a result, the thesis not only synthesizes existing approaches but also distils design principles for future optimization frameworks that are compatible with evolving European markets and the operational realities of high-RES systems.

Taken together, these three strands support a central conclusion: DERs are technically capable of supplying a large share of the ASs needed in 100% renewable power systems, but realizing this potential requires deliberate alignment of market products, grid codes and control strategies. Technology-neutral service definitions, clear performance metrics, and product specifications that reflect system needs under high VRE penetration are essential to avoid locking in solutions that unduly favor legacy synchronous generation. At the same time, market frameworks must recognize the multi-service nature of DER assets and provide remuneration schemes that reward simultaneous provision of energy, balancing and system-strength services without creating conflicting incentives or over-reliance on any single flexibility source. The evidence surveyed shows that when properly coordinated—through aggregators, virtual power plants, microgrid operators and TSOs/DSOs—DER portfolios can materially reduce operating costs, curtailment and emissions, while preserving or improving frequency and voltage performance.

This work also has several implications for future research and practice. Methodologically, there is a need for optimization and control frameworks that combine the rigor of mathematical programming with the scalability and adaptivity of distributed and data-driven methods, and that embed realistic representations of markets, network constraints, uncertainty and device degradation. Institutionally, regulators and system operators face the challenge of turning currently “implicit” capabilities—such as grid-forming behavior, synthetic inertia from DC-link storage, or load-side frequency response—into explicit, well-specified services that can be procured competitively and monitored transparently. From a planning perspective, integrated consideration of sector coupling, data-center flexibility and multi-energy systems will be essential for designing portfolios of resources that can deliver the diverse set of services outlined in the taxonomy at least cost. Finally, while this thesis has focused primarily on European markets and generalizable technical concepts, many of the insights on service design, provider mapping and coordination architectures are directly transferable to other regions pursuing deep decarbonization.

In conclusion, the thesis contributes a coherent conceptual bridge between the detailed technical capabilities of DERs, the evolving European market and regulatory landscape, and the ancillary-service needs of future 100% renewable electric power systems. By clarifying how services should be defined, which resources can provide them, and how existing optimization and control approaches can be leveraged and extended, it offers both a roadmap for researchers working on DER-based ASs and a set of actionable ideas for system operators and policymakers seeking to harness distributed flexibility in the next phase of the energy transition.

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List of acronyms

ACER	Agency for the Cooperation of Energy Regulators
AGC	Automatic Generation Control
AS	Ancillary Service
ASs	Ancillary Services
ASPs	Ancillary Service Providers
ASM	Ancillary Services Market
BESS	Battery Energy Storage System
BEGCT	Balancing Energy Gate Closure Time
BSPs	Balancing Service Providers
BSC	Black Start Capability
CAES	Compressed Air Energy Storage
CAM	Combinatorial Auction Mechanism
CfDs	Contracts for Difference
CHP	Combined Heat and Power
CGU	Conventional Generation Unit
C-EMS	Central / Cluster Energy Management System
DC-OPF	Direct Current Optimal Power Flow
DER	Distributed Energy Resource
DERs	Distributed Energy Resources
DISCOs	Distribution Companies
DMES	Distributed Multi-Energy Systems
DR	Demand Response
DRPs	Demand Response Programs
DRES	Distributed Renewable Energy Sources
DSOs	Distribution System Operators
DTR	Dynamic Thermal Rating
EBGL	Electricity Balancing Guideline
EENS	Expected Energy Not Supplied
EMP	Energy Management Platform
ERA	Eigensystem Realization Algorithm
ESP	Electricity Shifting Potential
EU	European Union
EUPHEMIA	EU Pan-European Hybrid Electricity Market Integration Algorithm
EVs	Electric Vehicles
FAT	Full Activation Time
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response

FiP	Feed-in Premium
FiT	Feed-in Tariff
FR	Frequency Regulation
FRC	Flexible Ramping Capability
FPFAPR	Fast Post-Fault Active Power Recovery
G2V	Grid-to-Vehicle
GFM	Grid-Forming (inverter)
GFL	Grid-Following (inverter)
HIL	Hardware-in-the-Loop
HPWHs	Heat Pump Water Heaters
HVAC	Heating, Ventilation and Air Conditioning
HVDC	High Voltage Direct Current
IBR	Inverter-Based Resource
IBRs	Inverter-Based Resources
ILES	Integrated Interruptible Loads Energy Storage
IM	Induction Motor
IMGs	Interconnected Microgrids
IR	Inertial Response
IRR	Internal Rate of Return
ICT	Information and Communication Technology
LFC	Load Frequency Control
LFAS	Load-Following Ancillary Service
LNG	Liquefied Natural Gas
LP	Linear Programming
LQG	Linear Quadratic Gaussian
MAS	Multi-Agent System
MILP	Mixed-Integer Linear Programming
MINLP	Mixed-Integer Non-Linear Programming
MIQP	Mixed-Integer Quadratic Programming
MIQCP	Mixed-Integer Quadratically Constrained Programming
MoU	Memorandum of Understanding
MPER	Maximum Profit Electricity Reduction
MPC	Model-Predictive Control
NP-RES	Non-Programmable Renewable Energy Sources
NPV	Net Present Value
OPF	Optimal Power Flow
P2H	Power-to-Heat
P2H2	Power-to-Hydrogen
PDR	Price-Based Demand Response
PEFC	Proton Exchange Membrane Fuel Cell
PHES	Pumped Hydroelectric Energy Storage
PHIL	Power Hardware-in-the-Loop

PHS	Pumped Hydropower Storage
PJM	PJM Interconnection
PMO	Population Migration Optimization
PMPSO	Population Migration Particle Swarm Optimization
PSO	Particle Swarm Optimization
PV	Photovoltaic
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RR	Replacement Reserve
RTS	Reliability Test System
SBES	Shared Battery Energy Storage
SDAC	Single Day-Ahead Coupling
SFC	Secondary Frequency Control
SI	Synthetic Inertia
SIR	Synchronous Inertial Response
SMC	Sequential Monte Carlo
SOC	State of Charge
SO	System Operator
SOs	System Operators
SOFC	Solid Oxide Fuel Cell
SR	Spinning Reserve
SSRR	Steady-State Reactive Response
STATCOM	Static Synchronous Compensator
TD	Transmission–Distribution (network)
TERRE	Trans European Replacement Reserves Exchange
TFC	Tertiary Frequency Control
TSO	Transmission System Operator
TSOs	Transmission System Operators
UPS	Uninterruptible Power Supply
UVAM	Unità Virtuali Abilitate Miste
V2G	Vehicle-to-Grid
VESS	Virtual Energy Storage System
VIR	Virtual Inertial Response
VPP	Virtual Power Plant
VPPs	Virtual Power Plants
VRFB	Vanadium Redox Flow Battery
VRE	Variable Renewable Energy
VUF	Voltage Unbalance Factor
WEM	Wholesale Electricity Market
ZIP	Constant impedance, current, and power load model

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