Quantified Carbon

Understanding the Full System Costs of the Electricity System

A STUDY BY QUANTIFIED CARBON

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ABOUT THIS PUBLICATION

This report has been prepared by Quantified Carbon (QC) for the United Nations Economic Commission for Europe (UNECE) with support from the World Nuclear Association (WNA). This study examines the full system costs of electricity systems, highlighting gaps in current modeling practices and proposing a holistic framework to achieve resilient, carbon-neutral power systems. It breaks down costs into plant-level, profile, balancing, ancillary services, grid, externalities, and flexibility, emphasizing the need for balanced energy mixes and advanced modeling to address future challenges like extreme weather and energy security. For deeper insights, the report is structured into two major parts: Part I offers an overview and high-level analysis of key challenges and gaps in power system planning, while Part II presents a technical deep dive into cost optimization modeling and critical system aspects often overlooked in models.

ABOUT QUANTIFIED CARBON

We are an international consultancy firm providing complex problem-solving, modeling, and optimization to support decarbonization of energy systems and industries.

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TABLE OF CONTENTS

TABLE OF CONTENTS 3
Executive summary 5
Rethinking cost metrics in power system planning 5
Understanding the full system cost of electricity with the novel SCBOE 5
Advances and gaps in cost optimization modeling 7
Charting the path forward: Holistic approach and policy-relevant insights 8
About this report 9
Part I: Overview and high-level analysis 10
1 Background 10
1.1 Power system planning and cost modeling 10
1.2 Problem statement and objective 12
1.3 Method and structure 13
2 Understanding the full system cost 14
2.1 Beyond conventional metrics 14
2.2 System Cost Breakdown of Electricity (SCBOE) 17
2.3 SCBOE in an illustrative case study 23
3 Key gaps, future modeling and conclusion 30
3.1 Key gaps 30
3.2 Modelling studies toward actionable and holistic power system planning 31
3.3 Conclusions 34
Part II: Technical deep dives 36
1 Resilient energy system 38
1.1 Different definitions and lack of consensus 38
1.2 Scope of resilience in this report 43
2 A general perspective of the development of cost optimization modelling 45
3 Frequency balancing services 47
3.1 Intraday power market 47
3.2 Balancing power market 49
4 Non-frequency ancillary services 56
4.1 Physical grid inertia 60
4.2 Grid strength level 60
4.3 Reactive power and voltage regulation 59

5 Copper plate grid limitation 62
5.1 Grid connection 62
5.2 Transmission grid (HVAC) 63
5.3 Regional and distribution grid 63
5.4 Interconnectors (HVDC) 64
6 Demand-side flexibility 65
6.1 Investment in flexibility infrastructure 65
6.2 Misalignment of generation- and consumer-centric perspectives 65
6.3 Cost of unserved energy and flexibility incentives 66
6.4 Risks of overestimating flexibility in energy models 66
6.5 Electricity price volatility 67
7 Extreme weather events and resilience 68
7.1 Historical analysis of extreme weather impacts on power systems 68
7.2 Climate change and increasing frequency of extreme events 71
7.3 Strategies for weather-resilient infrastructures 77
8 Security and defense 79
8.1 Wind project siting and security concerns 79
8.2 Energy security and geopolitics 79
9 Environmental and social impacts 84
9.1 Lifecycle environmental assessments of power systems 84
9.2 Trade-offs between resilience and environmental protection 87
9.3 Environmental risks associated with nuclear energy 88
9.4 End-of-horizon effects and unintended consequence 88
9.5 Social externality 89
10 Technology readiness level (TRL) risks 91
10.1 Grid-forming (GFM) inverter technology 91
10.2 Battery storage technology 92
10.3 Hydrogen storage technology 92
10.4 Nuclear reactor technology 93
References 96
List of Figures 108
List of Tables 110
Abbreviation 111

Executive summary

Rethinking cost metrics in power system planning

The global energy transition presents a complex challenge: how to decarbonize electricity systems while maintaining affordability and reliability. Historically, system planning has often relied on simplified evaluations of individual technologies, most notably using *cost metrics* such as the levelized cost of electricity (LCOE). While LCOE has become a commonly adopted benchmark among stakeholders, recent analyses have highlighted its significant limitations in capturing the full system-level perspective (Moraski *et al.*, 2025). Leading research and policy efforts now emphasize the need for sophisticated cost optimization modelling approaches that account for the complementary roles of different power assets, their collective impact on overall system costs, and the essential capabilities required for a resilient and affordable power system.

This study's objective is to enhance power system planning by deepening our understanding of full system costs, an essential step in supporting the development of resilient and carbon-neutral electricity systems. Specifically, we (i) examine cost metrics such as the levelized cost of electricity (LCOE) and their limitations in reflecting system-wide costs, (ii) identify key gaps in current cost-optimization modelling approaches, and (iii) highlight critical aspects of resilience that should be integrated into future planning frameworks.

Understanding the full system cost of electricity with the novel SCBOE

At an initial stage, this study reviews a wide range of cost metrics, all aiming to provide an accessible framework for understanding the role of technologies in power system planning. These range from the widely used, producer-focused LCOE to the levelized full system cost of electricity (LFSCOE), which allocates all system integration costs to each technology individually. While they represent opposite ends of the spectrum—one focused solely on plant-level costs, the other assuming each technology must provide all system capabilities on its own—neither fully reflects the interactions and complementary capabilities of diverse assets in a modern power system. Misuse of these metrics can therefore lead to misleading conclusions and poor policy decisions.

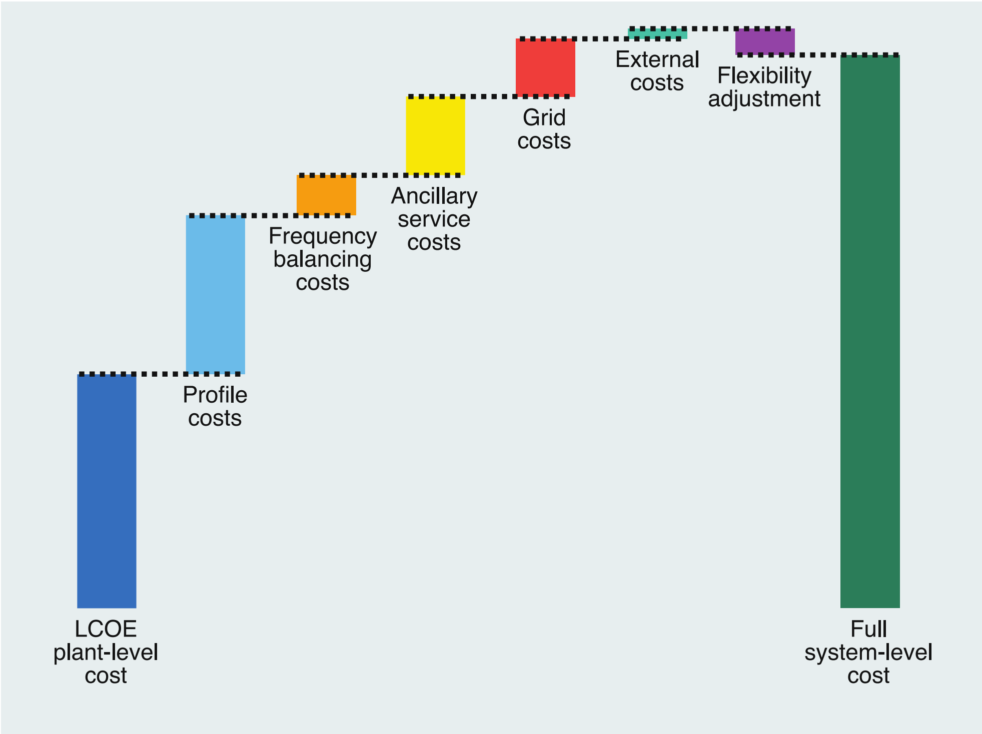

Figure 1. Illustration of the SCBOE cost components covering the full system cost of a variable renewable energy (VRE) resource.

We introduce a novel methodology to illuminate the system perspective that technology-focused cost metrics overlook. The analytical framework, denoted system cost breakdown of electricity (SCBOE), aims to bridge the gap between plant-level LCOE and system-level market and cost impacts by breaking the costs into key components. SCBOE's analytical framework draws its methodology from up-to-date market observations and literature to incorporate all cost components: technical and economic curtailment, market capture prices, power balancing, ancillary services, grid costs, externalities, and flexibility needs. As a primary objective, the SCBOE offers a valuable conceptual model for understanding the full system costs associated with electricity systems.

The resulting cost breakdown of the SCBOE is exemplified in Figure 1 for a low-LCOE variable renewable energy (VRE) resource such as wind and solar. As can be seen in Figure 1, the VRE effective cost increases significantly when accounting for integration requirements and utilization effects.

Cost-optimal electricity systems require a balanced mix of generation technologies. Different resources play distinct but interconnected roles. Low-LCOE VRE sources (wind and solar) provide low-cost energy supply during favorable conditions, while dispatchable resources such as energy storage and demand side response ensure system flexibility. Furthermore, dispatchable technologies, such as hydropower and gas turbines along with higher-LCOE firm resources, including nuclear, geothermal, and thermal power with carbon capture, together provide system stability capabilities and ensure resource adequacy. Crucially, their presence helps lower total system costs by avoiding overreliance on either extreme: too much VRE leads to low utilization and costly integration, while excessive firm capacity raises costs due to higher production costs. Nevertheless, a diversified mix including a significant share of firm generation reduces reliance on fuel import, vulnerability to weather variations and contingencies and increases utilization of the grid which together provides conditions that better drive decarbonization.

Figure 2 illustrates the balanced approach of the cost-optimal electricity system, often referred to as the "dinner plate model". The Nordic power system exemplifies this approach by combining Norway's flexible hydropower, Denmark's wind resources, and Sweden's nuclear capacity, thus creating a resilient low-carbon electricity system. The system cost breakdown of electricity (SCBOE) is introduced in this work as an analytical framework. It provides valuable insights conceptually, however, the methodology relies on approximate and generalized assumptions, which are not directly applicable to specific real-world power systems.

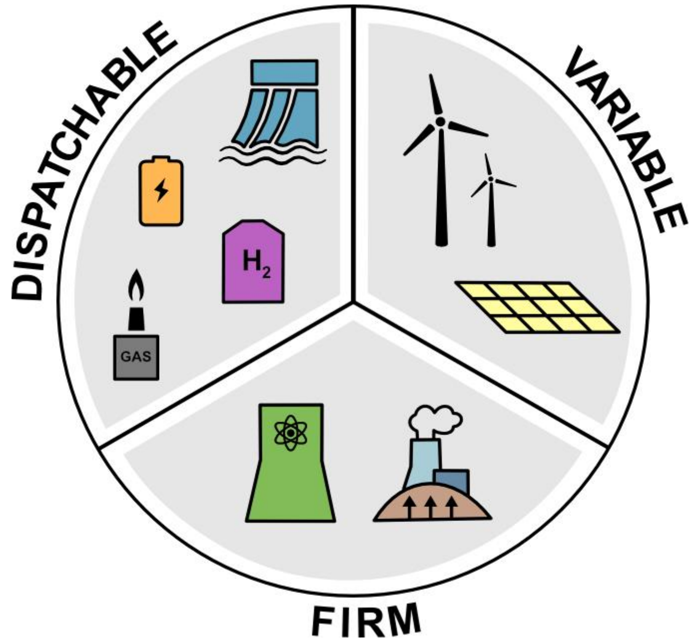

Figure 2. Dinner plate model of the technology mix for a robust and balanced electricity system.

Advances and gaps in cost optimization modeling

In contrast to cost metrics, including SCBOE, which merely provide a simplified snapshot of power system planning, cost optimization aims to comprehensively model system development by integrating investment and dispatch decisions with realistic power market dynamics. Throughout recent years, cost-optimization modelling has advanced significantly, enabling higher spatial and temporal resolution, multi-year horizons, and greater operational detail. However, as systems decarbonize and VRE shares grow, new challenges emerge, including intra-hourly variability, frequency stability, and prolonged low-generation periods ("energy droughts"), that remain difficult to fully capture in cost optimization modelling frameworks.

A resilient electricity system must withstand high-impact, low-probability events such as natural disasters, cyberattacks, or cascading failures, factors that are inherently difficult to model. Resilience is a recurring theme throughout this report, which offers a comprehensive review of challenges related to extreme weather, energy security, cyber-physical threats, and infrastructure vulnerabilities, all of which are critical considerations for power system planning.

In addition to resilience aspects, this work has further highlighted the need for improved modeling approaches to account for a wider spectrum of costs. Specifically, frequency and non-frequency ancillary services, grid integration costs, and flexibility options have been identified. While ongoing development efforts are closing many gaps, fully integrating all critical dimensions into optimization frameworks remains a complex task, particularly under deep uncertainty in future assumptions.

Charting the path forward: Holistic approach and policy-relevant insights

We argue that future studies must move beyond the narrow "cost–emissions" lens and adopt a more holistic, multidimensional approach. This includes developing a suite of quantified indicators that capture the essential capabilities of future power systems, spanning dimensions: competitiveness, energy security, environmental and climate impacts, transmission requirements, volatility and flexibility, and operational safety. Key indicators developed across Quantified Carbon's power system studies, reflecting such a methodology, are summarized in Table 1.

Table 1. Key evaluation dimensions and indicators for assessing future power system scenarios[1].

Dimension	Key indicators
Competitiveness	• Generation and capacity costs • Risk costs • Electricity price level
Energy security	• Power imports • Fuel imports • Critical materials use
Environmental & climate impacts	• Life-cycle greenhouse gas emissions • Land use
Transmission infrastructure	• Power transmission costs • Annual CO_2 captured & sequestered • Hydrogen storage capacity
Volatility and flexibility	• Electricity price volatility
Operational safety	• Firm/dispatchable capacity • Grid output levels

Looking ahead, this study highlights key areas for advancing power system modeling. Future research should expand quantitative key indicators to include:

- System balancing requirements (e.g., frequency control and ancillary services),
- Flexibility needs under uncertainty,
- A broader treatment of environmental externalities beyond greenhouse gas emissions including water resources and air pollution,
- System resilience under extreme operating conditions,
- Necessary political interventions, e.g., the role of subsidies and regulated markets, and,
- Socio-economic impacts, e.g., refined decarbonization pathways, industrial development and job creation

Beyond expanding this framework, it is crucial to standardize modeling studies, including scenario design, treatment of uncertainties and probabilistic distributions, and the reporting of

[1] See Section 3.2 for further information.

key indicators across the expert community. Establishing a common framework would enable transparent, consistent comparisons of power system scenarios, helping policymakers assess risks and trade-offs beyond a single cost figure and translate complex results into clear, actionable insights. Finally, further work is needed to ensure that quantitative findings are communicated effectively to policymakers.

As the current work's final conclusion, bridging the gap between advanced modeling and practical policy guidance remains a key priority, paving the way for more holistic assessments of power system pathways and more robust, informed decision-making. As modelling studies increasingly converge on which capabilities (here represented by quantified indicators) should be considered in power system planning, they lay a strong foundation for developing efficient market designs capable of driving a successful decarbonisation of the electricity system.

About this report

For deeper insights, this report is structured in two parts:

- Part I provides a high-level overview of power system planning. Understanding the full system costs through the lens of cost metrics is first presented. This part features a novel case study that breaks down key cost components and presents the underlying methodology. Key gaps in power system planning studies are summarized along with a forward-looking perspective is provided on modelling studies.
- Part II offers a more technical deep dive into cost optimization modeling and critical system aspects often overlooked in models — including balancing services, grid bottlenecks, demand-side flexibility, extreme weather, and energy security risks. It also highlights risks and readiness levels for emerging technologies like inverter-based resources, batteries, hydrogen, and nuclear power.

Part I: Overview and high-level analysis

1 Background

1.1 Power system planning and cost modeling

To achieve a resilient electricity system, it is recommended to maintain a well-balanced mix of variable, firm, and dispatchable energy resources, as illustrated by the dinner plate model in Figure 3. Just as a healthy body thrives on a diverse diet, the electricity system performs optimally when various energy sources complement each other effectively. In this model, variable renewables such as solar and wind power provide cheap electricity during favorable weather conditions. When solar and wind outputs decrease, dispatchable resources—like reservoir-based hydropower and short- and long-duration energy storage facilities such as batteries and hydrogen storage—can quickly step in to meet instantaneous power demand. These resources can be turned on/off or adjusted on demand to balance supply and load but may lack inherent firmness if limited by fuel or duration constraints.

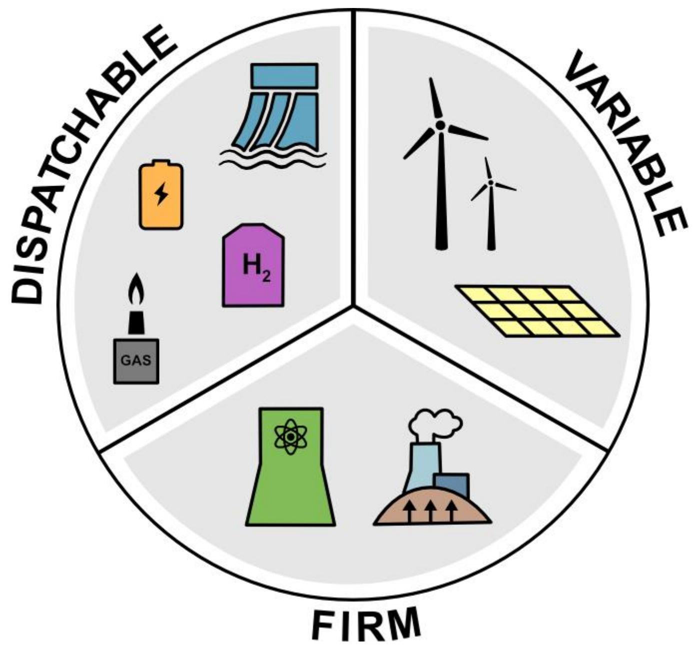

Figure 3 Dinner plate model of technology mix for a robust and balanced electricity system.

Notably, coal-fired power plants and combined-cycle and open-cycle natural gas turbine plants have long formed the backbone of supply-demand balancing in today's power systems. While these technologies also contribute to system stability, their combustion processes lead to substantial emissions. As the highest emitters, coal plants are slated for early retirement to help achieve climate targets. However, existing fossil fuel infrastructure can enhance energy security, as storing coal or oil on-site typically provides more reliable backup than relying exclusively on underground gas storage reserves. Meanwhile, highly flexible natural gas plants are expected to play an important role in maintaining cost-effective and reliable electricity supply until alternative technologies are ready to take over. They still produce emissions of at least 350 grams CO2 per kilowatt-hour (kWh); however, annual emissions can be reduced either by operating the plants fewer hours or by equipping them with carbon capture and storage (CCS) technology. CCS can also be integrated with bioenergy (BECCS) or direct air capture (Co-DACCS) to enable carbon dioxide removal.

Low-carbon, firm, non-weather-based resources, such as nuclear and geothermal energy, can provide a stable baseload supply and benefit from being located close to consumers. These are resources that are highly available and can reliably deliver power when needed, even during peak demand or system stress. Although economically less ideal for dispatchable operation, their consistent around-the-clock output maximizes grid utilization, potentially deferring the need for grid expansion. Furthermore, their reliable baseload generation can reduce reliance on costly system stability and flexibility measures while freeing up valuable dispatchable resources to be utilized more efficiently when truly necessary.

It should be noted that while hydropower can offer a firm, continuous output, its annual planning is less predictable due to the variability in weather-dependent water inflows. Historically, the Nordic power system exemplifies the successful implementation of the dinner plate approach for a highly decarbonized electricity system. Here Norway's dispatchable hydropower capacity, Denmark's substantial share of variable wind power, and Finland's and Sweden's combination of nuclear and hydropower collectively providing a diversified energy mix ensuring grid stability, resilience, and reliability.

Some would advocate for a limited "dinner plate," relying primarily on variable renewables supplemented by dispatchable resources— a strategy already applied in several power systems around the world. However, from a resilience standpoint, this approach could compromise the electricity system due to insufficient energy diversity. Dispatchable hydropower is a limited resource, and dependence on gas-fired power plants introduces vulnerabilities due to reliance on imports of a single fuel type (e.g., the European energy crisis, triggered by Russia's invasion of Ukraine in 2022). A narrowly focused electricity system might function adequately in an average weather year, but problematic weather conditions can drastically increase gas import dependency, potentially causing significant issues with price shocks amplified with compounded contingencies. In the end, a diversified electricity mix can possess important advantages, incorporating firm resources that reduce import vulnerabilities and preserve valuable dispatchable capacity for load-following and balancing variable renewable generation whilst also easing reliance on transmission infrastructure.

To achieve this optimal energy mix, cost optimization modeling serves as a critical tool in power system planning. It employs advanced optimization techniques to determine the most cost-effective mix of these resources that can meet projected electricity demand under a variety of constraints and scenarios. The goal is to minimize the total cost of building and operating the power system while ensuring reliable and robust electricity supply and meeting resilience and decarbonization targets. This includes high-resolution temporal (e.g., hourly) and spatial granularity, interconnections between regions, energy storage, demand-side flexibility, and other system constraints. Importantly, these optimization models rely on accurate cost metrics as fundamental inputs.

Historically, system planning has often relied on cost metrics, i.e., simplified evaluations of individual technologies, most notably using the levelized cost of electricity (LCOE). While LCOE has become a commonly adopted benchmark among stakeholders, recent analyses have highlighted its significant limitations in capturing the full system-level perspective (Moraski *et al.*, 2025). LCOE should be used only to compare generation technologies that operate similarly and primarily provide energy services (Mai *et al.*, 2021). At most, it offers an initial screening tool to highlight potentially competitive options. While variations of the LCOE metric attempt to compare diverse technologies and reflect their interactions with the grid, doing so demands a far more comprehensive set of assumptions about the characteristics and needs of the specific power system in question. This is where cost optimization modeling becomes essential. The cost optimization modeling goes further to simulate the entire system under operational constraints, weather variability, and policy requirements.

The connection between the two lies in how they inform and support each other. Cost metrics provide relevant input parameters and serve as references for cost optimization models, as preliminary indicators of technological competitiveness. Meanwhile, cost optimization modeling can contextualize the interpretation of cost metrics. By modeling the deployment of different technologies within a full-system context, it becomes possible to quantify their actual contribution to system economic competitiveness, resilience, and emissions reduction. This allows for the calculation of more advanced and informative cost indicators, which incorporate system-wide costs. Moreover, cost optimization modeling helps overcome the limitations of simplistic comparisons implied by cost metrics. Technologies cannot be adequately evaluated in isolation because their performance and cost-effectiveness are highly dependent on the system they operate within. Taking the same example above, a photovoltaic system, for instance, may have a low LCOE but require complementary investments in storage or flexible generation to meet evening peak demands. Only a full system model can capture such interdependencies and trade-offs. Thus, cost metrics are best understood not as definitive measures of value, but as components in a broader analytical framework anchored by system-level modeling.

1.2 Problem statement and objective

While the dinner plate model offers a balanced framework for a reliable electricity system, achieving both resilience and carbon neutrality remains particularly challenging in countries such as Poland and Germany. With limited hydropower potential, these nations may need to rely more heavily on hydrogen and battery energy storage to provide dispatchable capacity. To enhance energy resilience, they must also leverage a combination of stronger grid interconnections, increased demand-side flexibility, and a diversified mix of renewable energy resources.

In the absence of large hydropower reservoirs, ensuring power adequacy during extended periods of low wind and solar generation—so-called energy droughts—is facilitated by the strategic deployment of firm, low-carbon resources (e.g., nuclear, geothermal, and fossil or bioenergy plants equipped with CCS). This should be accompanied by cyber-resilient investments in grid infrastructure and modernization, as well as decentralized solutions like standalone microgrids, which can provide critical services in the event of cyberattacks or localized grid failures—even if their contribution to mitigating long-duration energy droughts is limited.

Modern power system planning has fundamentally shifted from traditional capacity-based adequacy metrics to a continuous 24/7 energy generation and delivery equation. Furthermore, the complexity of power system planning is amplified by external factors, including extreme weather events, evolving electricity demand patterns, and advancements in energy storage and transmission technologies.

Nonetheless, achieving reliability, cyber-security, resilience, and carbon neutrality involves significant potential costs that must be carefully managed. Current modeling practices often fail to adequately incorporate these expenses but primarily focus on direct generation costs such as the use of cost metrics. Cost metrics, while useful, are insufficient on their own to capture the temporal, spatial, and systemic dimensions of modern power systems. To avoid misguided energy policy decisions, it is essential to improve understanding of how these metrics should—and should not—be used in planning and analysis. Addressing these gaps will require more comprehensive modeling approaches that incorporate the full spectrum of aspects related to grid upgrades, firm capacity, storage, and climate adaptation to ensure that the transition to a resilient, carbon-neutral electricity system is both economically viable and sustainable.

This study's main objective is to enhance power system planning by understanding the full system costs, enabling the development of resilient, carbon-neutral electricity systems. To achieve this, we pursue the following sub-objectives:

- Enhance understanding of cost metrics (e.g., LCOE) and their role in capturing a comprehensive, system-level cost perspective;
- Identify key gaps in current cost-optimization modelling approaches to guide future research and methodology development; and,
- Highlight critical dimensions of resilience that must be integrated into planning frameworks for power systems undergoing decarbonization.

1.3 Method and structure

This report adopts a synthesis-driven methodology that integrates findings from academic literature, industry publications, empirical data, and illustrative case studies. To address the objectives presented above, the report is organized into three core sections, each directly contributing to the main objective and sub-objectives:

- Section 1 establishes the context, articulates the problem, and sets out the main objective and sub-objectives. It introduces key challenges in electricity system resilience and cost modeling, providing the rationale for a more holistic cost assessment framework.
- Section 2 addresses the first sub-objective by critically reviewing conventional cost metrics—such as LCOE, VALCOE, LFSCOE, and others—and examining how these can be expanded or reinterpreted to better reflect full system costs. It also addresses the second sub-objective by identifying key modeling gaps—particularly in relation to grid integration, flexibility, ancillary services, and extreme event resilience—that are not captured by current cost-optimization models. Finally, it introduces a structured full-system cost framework and offers a stylized example that integrates these various cost components.
- Section 3 addresses the third sub-objective by synthesizing insights on critical resilience dimensions—such as system balancing, extreme weather preparedness, cyber and physical security, and supply chain vulnerability—and discusses how these elements should be integrated into future modeling practices. It concludes with targeted recommendations for improving cost modeling approaches to better support resilient and sustainable power system planning.

The report aims to provide actionable guidance for researchers, planners, and policymakers working to strengthen the resilience, carbon-neutral, and cost-effectiveness of future electricity systems.

2 Understanding the full system cost

This section begins by examining both the capabilities and limitations of the current cost modeling practices and then transitions to a detailed exploration of the full system cost framework. This framework addresses critical gaps in current modeling by incorporating balancing costs, grid integration costs, flexibility-associated costs, and externalities such as environmental and social impacts.

2.1 Beyond conventional metrics

Electricity system modeling relies on a variety of cost metrics and cost categories to evaluate the economic viability of power generation technologies and their impact on the broader energy system. No single metric captures all cost components, as each is designed to address specific aspects of generation, integration, and value on the electricity market. Understanding the strengths and limitations of these metrics is crucial for effective decision-making in energy policy, market design, and investment strategies.

The levelized cost of electricity (LCOE) has long been the foundational framework for comparing the direct costs of electricity generation across different technologies. The LCOE is defined as follows:

$$LCOE = \sum_{i=1}^{N} \frac{C_i}{(1+r)^i} \Big/ \sum_{i=1}^{N} \frac{E_i}{(1+r)^i}$$

The numerator of the LCOE includes all costs: investment, operation and maintenance (O&M), and fuel expenditures, while the denominator represents the electricity produced over the system's economic lifetime *(N)*. Future costs *(C_i being total costs in year i)* and generation *(E_i being total electricity generated in year i)* are discounted using a real discount rate *(r)* to account for net present value (NPV).

The widespread use of LCOE is due to its simplicity and ability to provide a standardized, plant-level metric to cover all the relevant financial aspects without overcomplicating the overall analysis (Strantzali *et al.*, 2017). It is particularly useful for comparing similar generation technologies and shaping subsidy policies to support the clean energy transition. Originally, LCOE was designed to predict electricity costs for firm, dispatchable generation resources in regulated power markets (IEA & NEA, 2020). Recently, however, it has been applied to non-firm, variable generation resources in deregulated markets. This expanded use has led to its application in system-level analyses and comparisons of inherently non-comparable energy technologies (IEA&NEA, 2020). On the system level, the challenge is the disconnection between the LCOE metric and the resulting electricity price formation in today's power markets. Given this issue, the use of LCOE should be communicated more accurately to avoid misleading policymakers and decision-makers (Emblemsvåg, 2025). LCOE remains useful in certain cases, but complementary metrics have been developed to address its limitations while maintaining its core strengths.

To provide a more comprehensive representation of the economic impact of different generation technologies on the broader electricity system, the levelized full system cost of electricity (LFSCOE) metrics were introduced to not only contain standard LCOE but also include integration costs (Idel, 2022). The integration costs account for balancing, grid, and profile costs to better reflect the indirect costs that occur at the system level. It is a novel metric that compares the costs of serving the entire market using a single energy source plus storage (Idel, 2022). While LCOE assumes that a generation source has no obligation to balance the market and supply obligations, LFSCOE assumes that the source has maximal balancing and supply obligations. This means that the technology must fully accommodate demand fluctuations and ensure supply reliability by storage. Nonetheless, this approach underrepresents the synergies and complementarity between different energy technologies in a balanced energy mix.

This analysis focuses on non-fossil technologies and therefore does not cover natural gas combined-cycle power plants. However, due to their high operational flexibility, these technologies show relatively low variation when moving from LCOE to the levelized full system cost of electricity (LFSCOE), as demonstrated by Idel (2022). This stability suggests that natural gas may be suited to complement variable renewable energy sources by addressing intermittency and supporting system reliability, potentially serving as an important transitional resource in the decarbonization pathway. At the same time, their substantial emissions and exposure to volatile fuel prices introduce significant uncertainty in absolute cost levels, complicating their inclusion in the comparative analysis presented here.

The competitiveness of power generation technologies should be evaluated by both considering technology costs and system values they can provide. These values include contributions to the bulk energy supply, including power adequacy and system flexibility. The value-adjusted LCOE (VALCOE), introduced in the World Energy Outlook, incorporates the system value while also building on the foundation of the LCOE (IEA, 2019). It includes the estimates of energy, capacity, and flexibility values. Energy value reflects the importance of the electricity produced at different times. Capacity value measures the contribution of a technology to the system's ability to meet peak demand reliably. Flexibility value assesses how well a technology can adjust its output in response to real-time changes in supply and demand. The estimated value of each technology is compared against the baseline value to calculate the adjustment, either up or down, to the LCOE. Based on the adjustments, VALCOE provides a basis for evaluating competitiveness (IEA, 2024a). This approach provides more robust comparisons between dispatchable and non-dispatchable sources by recognizing their distinct contributions to system reliability and flexibility. However, VALCOE does not include externality costs, such as environmental costs such as the social cost of carbon and the loss of land and ecosystems, where they are not priced in the market, nor does it include site-specific grid integration costs or system reliability contributions, such as essential ancillary services.

The levelized avoided cost of electricity (LACE), developed by the U.S. Energy Information Administration (EIA), approaches the value evaluation from another direction (EIA, 2018). LACE estimates the cost that would be incurred if the electricity generated by a new project had to be replaced by alternative sources, offering a measure of its market value. Since LACE varies by location due to differences in resource availability, fuel costs, and market conditions, it is useful for location-specific assessments. A generation asset is generally considered economically viable when its LACE exceeds its LCOE at a given time and place, as this suggests that its market value outweighs its production cost. However, real-world investment decisions are more complex than a simple LCOE-to-LACE comparison. Factors such as grid integration costs, regulatory incentives, and long-term market uncertainties influence economic feasibility. Nonetheless, the difference between LACE and LCOE provides a useful high-level indicator of a power plant's economic attractiveness.

While the above cost parameters focus on the costs borne by producers, the social cost of electricity (SCOE) emerges as a relevant metric to incorporate the external costs (often referred to as externalities) associated with electricity production, providing a more holistic assessment of a technology's true cost to society (Khosravani *et al.*, 2023). It includes both direct costs (like capital and operation and maintenance expenses) and external costs imposed on society and the environment, such as environmental damage, carbon emission, and public health impacts. However, it ignores common mode failures of the system when large amounts of generation become unavailable due to extreme environmental conditions. These need to be considered to ensure the system will have sufficient reliability and resilience to meet the needs of society when the conditions are experienced. In the end, it is not enough to focus only on the producers; it is also necessary to serve the consumers and ensure attractive power market conditions.

While the LCOE can give the impression that VRE resources tend to be the cheapest alternatives, the LFSCOE finds them to be the most expensive sources of energy, as seen inTable 2. The proposed system LCOE for VRE (not included in the table) lies between these two values (Ueckerdt *et al.,* 2013), while VALCOE, from the International Energy Agency (IEA), is slightly above their LCOE values.

Finally, Lazard proposes the levelized cost of firming variability (LCOE, including firming), which takes into account the actual firming costs for the particular grids analyzed (Lazard's LCOE+, 2025). Lazard offers two approaches to add firming costs to make the LCOE of VRE more comparable to the LCOE of firm power plants. In the first approach, Lazard adds storage to a solar plant (with lithium-ion battery configuration of 50% of the capacity of the solar PV plant and a 4-hour duration). However, this approach falls significantly short to making the 'firmed' solar plant equivalent in the services provided by, e.g., a firm gas plant. In the second approach, Lazard incorporates part of the cost of a natural gas peaking plant into the LCOE of VRE to bring the Effective Load Carrying Capacity (ELCC) of the VRE plant to 100%. Arguably, this combination is more 'firm' than a solar or wind plant alone, but still would not provide the same grid services as a firm power plant (EPRI, 2025).

Notably, the comparison in Table 2 does not include dispatchable power technologies, such as battery storage, combined-cycle and open-cycle gas turbines and hydro reservoir power. This is primarily because the market profitability of these technologies depends heavily on the specific characteristics of the power market in which they operate—including assumptions about CO_2 prices, price volatility, and weather conditions. As such, the role of dispatchable technologies is best evaluated through a more systemic lens, ideally using high-resolution market modelling.

Table 2. Comparison of different metrics to account for the cost of electricity of solar, wind, nuclear, and biomass.

Metric	Solar Photovoltaic (PV)	Wind	Nuclear	Biomass	Reference
LCOE	\$36/MWh	\$40/MWh	\$82/MWh	\$95/MWh	(Idel, 2022)
	\$45–\$55/MWh	\$40–\$60/MWh	\$75–\$170/MWh	n/a	(IEA, 2024b)
	\$27–\$73/MWh	\$29–\$92/MWh	\$142–\$222/MWh	n/a	(Lazard's LCOE+, 2025)
VALCOE	\$50–\$70/MWh	\$45–\$70/MWh	\$75–\$160/MWh	n/a	(IEA, 2024b)
LCOE incl. firming	\$67–\$153/MWh	\$49–\$177/MWh	n/a	n/a	(Lazard's LCOE+, 2025)
LFSCOE-95	\$177–\$749/MWh	\$131–\$243/MWh	\$90–\$96/MWh	\$90–\$95/MWh	(Idel, 2022) (B of A securities, 2023)
LFSCOE-100	\$413–\$1380/MWh	\$291–\$483/MWh	\$105–\$122/MWh	\$103–\$117/MWh	(Idel, 2022) (B of A securities, 2023)

2.2 System Cost Breakdown of Electricity (SCBOE)

To bridge the gap between existing cost metrics to a more holistic assessment of full system costs, it is important to recognize that traditional cost measures merely provide insights on specific aspects of the economics. The approaches often struggle to reflect real-world system dynamics, such as the impact of network constraints, the cost of maintaining flexibility (including frequency, ramping, inertia, etc.), impacts from increased vulnerability such as extreme weather events, and externalities like climate and social costs, which leaves critical gaps in understanding the full system costs of the electricity system. As energy systems become more complex, there is a growing need to expand beyond conventional cost metrics to capture a more holistic view of system-wide economic impacts.

We introduce a novel methodology to illuminate the system perspective that technology-focused cost metrics overlook. The analytical framework, denoted the *System Cost Breakdown of Electricity* (SCBOE), bridges the gap between plant-level LCOE and system-level market and cost impacts by breaking the costs into key components. Building on earlier work (OECD & NEA, 2021), in addition to the plant-level production costs (LCOE), the SCBOE incorporates grid-level components: balancing costs, grid integration costs, and flexibility-related expenditures, as well as social and environmental costs (external impacts).

Figure 4 depicts a stylized example of all the major cost categories for a balanced system with a fair share of VRE and non-VRE resources, cf., the dinner plate model introduced in Section 1.1. We observe that typically the LCOE of the VRE resource is only a fraction of the total system costs while the non-VRE resource has a relatively high LCOE but the same full system cost in a cost-optimized electricity system.

The example of Figure 4 (a) demonstrates how adjustments for capacity factors, value factors, market dynamics, ancillary services, grid costs, and externalities adjust the LCOE plant-level cost. Nevertheless, these cost categories are not limited to VRE. Figure 4 (b) indicates the same cost categories for a non-VRE resource reaching the identical full system cost in an optimally balanced system. Please note that there are many apparently contradictory definitions when it comes to system costs in energy system planning. When planning a cost-optimal energy mix, removing any energy technology from that mix will increase the total system costs due to other less suitable technologies having to fill that empty niche. This applies to both low-LCOE sources and high-LCOE sources, as clearly shown in Figure 4. Nevertheless, it emphasizes the need to understand the full system costs. Important terms for the profile costs are listed in Table 3 below.

Flexibility can reduce the effective cost of variable renewable energy (VRE) resources. Storage technologies and demand-side flexibility shift consumption toward low-price hours, effectively raising market prices during periods of high VRE production and increasing revenues for VRE producers. Conversely, these resources shift demand away from high-price hours, smoothing price peaks when VRE output is low, which has limited impact on VRE revenues. This is why flexibility results in negative adjustment costs in Figure 4 (a). However, from a societal standpoint, flexibility comes at a cost, ranging from lower industrial output and revenue due to reduced operational efficiency and the expenses involved in ramping processes up or down, despite the benefits it offers to producers of electricity.

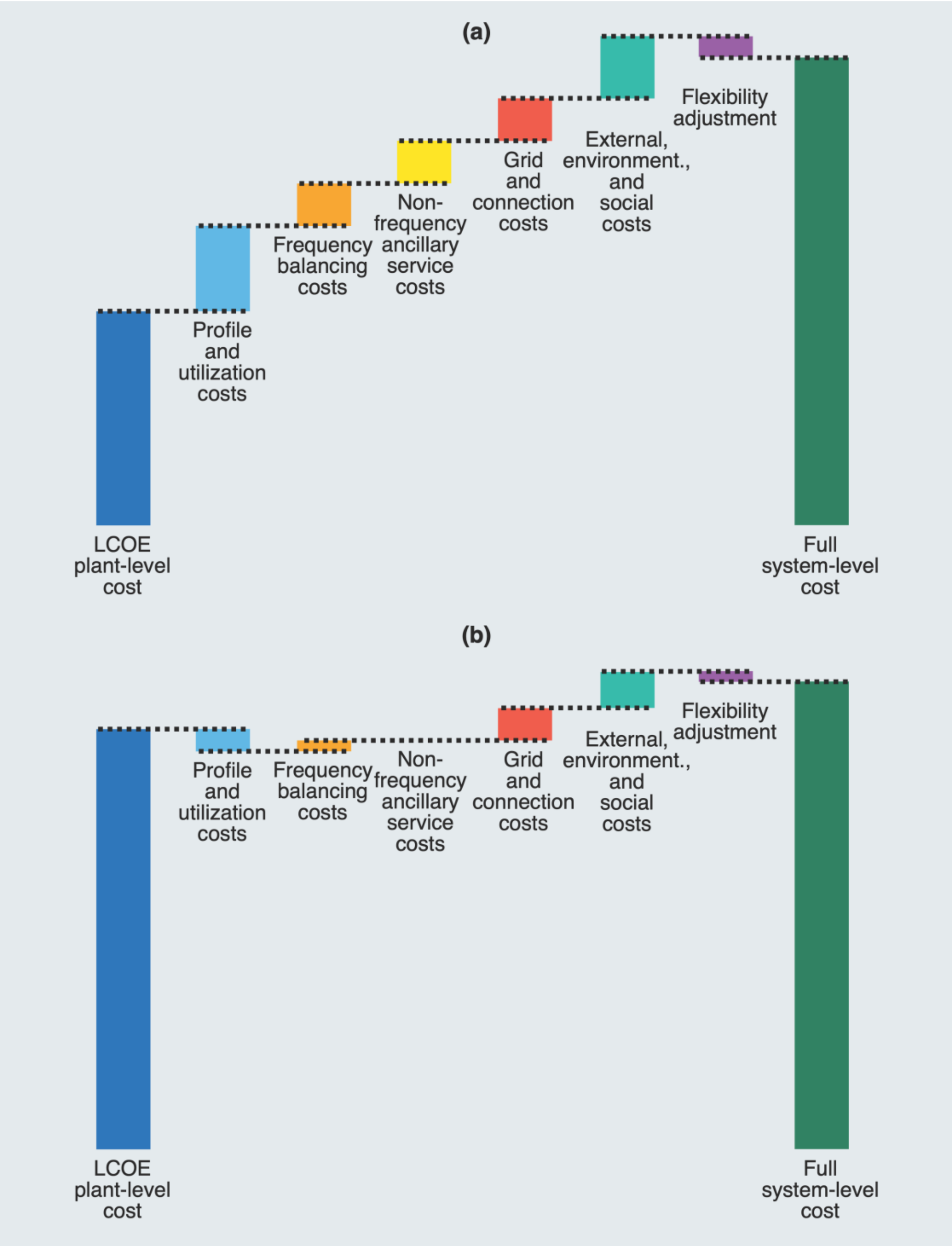

Figure 4 Illustration of the different cost categories covering the full system-level cost in the SCBOE framework. (a) VRE inverter-based resources. (b) Firm, plannable synchronous resources.

Table 3. Description of different terms used when assessing the full system cost.

Term	Definition
Value factor (capture rate)	The ratio of the power plant's average sales price to the overall average market price over the same period. It describes how well it matches its outputs to the higher-priced hours. The phenomena of VRE's reducing the value factor are often described as price cannibalization.
Capacity factor (utilization rate)	A measure of how much electricity is generated over a given period of time relative to a power plant's maximum power output if it ran at full (nameplate) capacity that entire time. Reduced capacity factors can be the result of lower VRE weather resources, curtailment of power output, or lower utilization of gas peaker plants to balance the electricity system.

In addition to the pure cost of power generation, often expressed through the LCOE, the resources, labor, and environmental impacts associated with energy production from a specific source are distributed throughout the entire system. These impacts, known as externalities, represent costs or benefits that are not reflected in the market price of electricity but are borne by society or the environment. Externalities can either increase or decrease the overall societal cost of production.

Broadly speaking, the full system-level cost in the SCBOE is organized into the following cost categories. A more detailed technical deep-dive can be found in Part II of this report.

1) Plant-level cost: The plant-level costs represent the first level of economic analysis. It includes a) the cost of building the power generating plant, b) the cost of fuel used for generation, and c) the operation and maintenance costs. When discounted over the whole economic lifetime of the project, plant-level costs are normalized when calculating the LCOE, which may sometimes include the cost of carbon reflected on carbon taxes. In essence, the LCOE describes the break-even electricity price needed to cover all plant-level costs during a power plant's capital recovery period.
2) Profile and utilization costs: A major simplification with the LCOE is the assumption that a power market's volumetric wholesale electricity price is equal to the captured electricity price of a particular power plant, referred to as "capture rate" in Table 3. VRE resources tend to produce more electricity in low-price periods and less in high-price periods. As a result, their sales prices are typically a fraction of the wholesale price of electricity, which is defined as the value factor (see Table 3). Hypothetically, if the sales price is cut in half, the value-factor-adjusted LCOE doubles. Before 2020, the value factor of wind power dropped below 80 percent (Eising *et al.*, 2020), which increased the cost by at least 25 percent. However, it is not only the value of the electricity that matters but also the utilization. The average capacity factor (see Table 3), or productivity, of wind power in Germany dropped from 45.7 percent to 36.1 percent between 2015 and 2022 (Statista, 2023), which alone increased the average profile-adjusted, break-even fleet LCOE by 26.6 percent. Please note that these average impacts can be larger or lower for individual plants. However, the costs can both be related to wind resources or to economic- and grid-curtailed production. So, considering both value and capacity factors, the profile costs can add significantly to the baseline LCOE. In this respect, the overall energy mix is also important to consider, as a balanced energy mix contributes to improving both the value and capacity factors of VRE resources (Hjelmeland *et al.,* 2025).

3) Frequency balancing costs: The cost of balancing is not necessarily limited to the energy volumes produced by different generation resources. Primary reserves are emergency-only, on-demand backup production dimensioned to step in to cover up for an outage of power from the largest single component of a power system. This is the reason why firm non-VRE resources like nuclear power plants will also have frequency balancing costs. However, these costs do not increase with the energy volume as is the case for VRE resources but tend to reduce with a larger fleet of reactors relative to the overall electricity generation. Moreover, balancing costs also include large inverter-based interconnectors between countries where external VRE resources can influence internal balancing costs. Other reserves are related to the intermittent balancing of VRE resources, where a fraction of their capacity needs to be allocated in balancing reserves. Some of the balancing can also be addressed in the intraday market, which corrects for the fact the forecasted generation day ahead is not necessarily equal to the actual generation closer to real-time. The intraday market allows VRE producers to make corrections that will be more expensive to compensate if they later should be addressed through energy activation in the balancing power market closer to delivery. Nonetheless, balancing costs tend to look small when they are spread out and averaged over all megawatt-hours of generation. However, if the integration of a particular energy resource with a 10 percent share has increased the system-wide balancing costs by \$1/MWh, the actual balancing costs of that energy resource is \$10/MWh (Hirth *et al.*, 2015). Please note that these costs evolve over time, depending on the location, and vary as a function of the share of that energy resource. To reduce balancing needs, the intraday market serves as a bridge for clearing out day-ahead errors in the production forecast. This implies that this market should also be included in the frequency balancing costs.
4) Non-frequency ancillary service costs: These costs are the additional costs to maintain a fully functioning power system in addition to the frequency balancing at every time instant. It includes physical system inertia, short-circuit capacity, congestion management, and voltage regulation. Please note that these services are already provided by existing synchronous resources such as nuclear power plants and hydropower plants. Depending on the local market, these ancillary services are either taken for granted or compensated economically. Nevertheless, ancillary service markets should be developed in the near future for these services. For systems with large shares of VRE, these costs could be up to \$20/MWh at the plant level (Nøland *et al.*, 2024a).
5) Grid and connection costs: Different power systems have different consumption patterns and a mix of energy resources with different capacity factors. This inevitably leads to different grid utilization levels, influencing the need for grid expansions and reinforcements. If lower-capacity factor VRE resources will supply two-thirds of the energy mix of Europe in 2050, the transmission grid capacity will increase fivefold (Golombek *et al.*, 2022). However, this is also related to the growth in electricity demand, which could necessitate an even large grid expansion. Alternatively, higher shares of firm resources exhibiting higher capacity factors near consumers could inevitably lead to grid expansion deferral, reducing overall grid costs. Grid connection costs that may be associated to different resources come in addition to the macro-scale transmission grid costs. The National Renewable Energy Laboratory (NREL) has a baseline grid connection cost of \$100/kW of any energy resource. However, this cost category increases orders of magnitude for more dispersed and offshore resources (NREL, 2024a).
6) External, environmental, and social costs: The final level of analysis addresses the full costs of the system, including external, environmental, and social costs. These cover any extra cost that technologies impose on the well-being of people and communities, whether

these are positive impacts, such as effects on economic development, or negative impacts, like changes in land use, air pollution, or greenhouse gas emissions. However, some of these costs could be perceived as subjective, which makes it difficult to establish a consensus. It could also include positive impacts regarding the reduction of the social cost of carbon. Different resources have inherently different land use (Nøland *et al.,* 2022) and societal acceptance in terms of the so-called "not in my backyard" (NIMBY) phenomenon (Asokan *et al.*, 2024). Quantifying the full social and environmental externalities provides a comprehensive framework to evaluate and compare the costs of various generation options on the same basis in terms of societal barriers and sustainability metrics.

7) Flexibility options: If the consumption-side has economically favourable flexibility options, the full system-level costs can be reduced. However, this depends on the incentives from the demand side. For example, if the consumer has high variable operational costs, some costs can be saved when not consuming electricity in high-priced hours. However, if a heavy industry consumer mostly has fixed costs independent of how many hours they operate, more consistent 24/7 electricity use is desired, which increases the societal cost of flexibility. Nevertheless, flexible consumption can reduce the profile costs of VREs and is often regarded as a negative contribution from the producer's perspective.

As discussed above, several additional costs associated with power generation are not reflected at the plant level, particularly externality costs such as carbon emissions from fossil fuel-based technologies. Some of these costs are currently partially covered by carbon pricing mechanisms, such as through the cap-and-trade structure of the EU Emissions Trading System (EU ETS). However, because fossil-fueled power plants frequently dominate price formation in European electricity markets (Gasparella et al., 2023), their bids effectively impose an implicit carbon cost on all electricity generation during periods when fossil fuels set the market price. This situation generates additional system-wide costs, especially in hours when fossil generation faces limited competition in market clearing. Nevertheless, carbon pricing elevates the bidding prices of fossil-based generation, thus improving the competitiveness of higher-cost, dispatchable, low-carbon technologies, such as fossil generation equipped with CCS and hydrogen-fueled power plants.

Other important cost drivers are seen in power systems with a high share of VRE resources, which, due to their nature, exhibit higher levels of variability in production. These additional costs depend on the availability of flexible resources, such as dispatchable backup, storage, digitalization, market structure, and interconnections for electricity trading. Nevertheless, the prevalence of reservoir-based hydropower, e.g., in the Nordic power system, can impact these costs, which would be different in other regions of Europe.

Whereas fossil fuel-based generation primarily influences a single cost component, power systems with a high share of VRE resources simultaneously affect multiple cost elements. Although all energy technologies contribute to overall system costs, the variability of VRE results in significantly higher system costs at higher VRE shares. Therefore, these factors must be accounted for when comparing VRE with firm nuclear, geothermal, or fossil fuel-based generation. Nevertheless, with a balanced share of VRE, their cost impact shifts, as allocating cheap resources can reduce costs more effectively than the system-level costs they introduce.

Table 4 summarizes all the full system-level cost categories of the SCBOE framework. Some would argue that the full costs still lack consideration for power plant lifetime (OECD, 2020), material intensity, or energy return on investment (EROI) (Weißbach *et al.*, 2013).

Table 4. Overview of the full system-level costs (OECD & NEA, 2021) (OECD, 2022), including the social costs of electricity generation technologies (Samadi, 2017).

1) LCOE plant-level cost	2) Profile & use costs	3) Freq. balancing costs	4) Non-freq. ancillary service costs	5) Grid and connection costs	6) External, environmental, and social costs	7) Flexibility options
Capital expenditure (CAPEX) Fuel costs O&M costs Recycling costs Carbon price	Value factor adjustment Capacity factor adjustment Power curtailment VRE resources change over time	Intraday power market costs Balancing power market costs Imbalance penalties	Local grid inertia Short-circuit capacity Reactive power support & voltage regulation Island & black-start capability Congestion management	Grid connection Transmission grid expansion (high-voltage alternating current, HVAC) Distribution grid expansion Interconnector expansion (HVDC)	Social carbon costs minus carbon price Noise pollution Air pollution Land footprint costs Ecosystems costs Toxic & radioactive waste costs	Demand-side flexibility Sector coupling Peak shaving Energy storage

2.3 SCBOE in an illustrative case study

An illustrative case study of the full system costs in the SCBOE framework of a stylized VRE resource is presented in this subsection. The focus is to understand how different cost drivers influence the cost and to cover the basics of calculating the full system costs. The following cost categories are included in the case study:

1. LCOE plant-level – a representative VRE LCOE number for the generation costs at the site level;
2. Profile and use cost adjustments – reflecting the capacity and value factors of VRE resources;
3. Frequency balancing costs – including intraday market re-trading and balancing market procurements;
4. Non-frequency ancillary service costs – associated with maintaining grid stability and operability;
5. Grid connection costs – including expenses for electricity grid upgrades needed for grid connection;
6. External costs – including the carbon intensity of power curtailment and the social carbon costs; and,
7. Flexibility costs – limited to the generation side in this illustrative example, ignoring the consumer side.

To illustrate the full system costs in the SCBOE of deploying and integrating a VRE resource, Table 5 presents a worked example based on basic VRE assumptions. In this case, the full system cost is 147.6% higher than the baseline LCOE of $50.0/MWh, resulting in a total cost of $123.8/MWh. This figure falls within the mid-range of Lazard's 2024 LCOE+ estimates, which include the levelized cost of firming intermittency (Lazard's LCOE+, 2025). However, the total cost of $123.8/MWh is sensitive to the assumptions made within each cost category, which can vary over time and across different markets and locations. Nevertheless, the example offers a transparent, step-by-step framework that can be adapted to more specific case studies. A detailed explanation of the methodology for each cost category is provided below in Table 5. Note that the flexibility cost appears as a negative value, reflecting the producer's perspective. From a societal standpoint, however, these savings for the producer may translate into additional costs for the consumer, which is disregarded in the illustrative case study.

Table 5. Stylized example of full system costs covering all cost elements using the described basic assumptions.

#	Cost element	Basic assumptions	Value
1)	LCOE plant-level	\$50/MWh baseline levelized cost of electricity (unadjusted)	\$50.0/MWh
2a)	Capacity factor adjustment costs	85% use rate relative to baseline capacity factor (e.g., due to curtailment) \$50/MWh ÷ 0.85 = \$58.8/MWh → \$58.8/MWh – \$50/MWh = +\$8.8/MWh	+\$8.8/MWh
2b)	Value factor adjustment costs	70% capture rate of wholesale day-ahead market price \$58.8/MWh ÷ 0.7 = \$84.0/MWh → \$84.0/MWh – \$58.8/MWh = +\$25.2/MWh	+\$25.2/MWh
3a)	Intraday selling costs	10% intraday selling volume at 80% of day-ahead sales price \$58.8/MWh × (0.9 + 0.1 ÷ 0.8) = \$60.3/MWh → \$60.3/MWh – \$58.8/MWh = + 1.5/MWh	+\$1.5/MWh
3b)	Intraday buying costs	10% intraday buying volume at 120% of day-ahead sales price \$58.8/MWh × (0.9 + 0.1 × 1.2) = \$60.0/MWh → \$60.0/MWh – \$58.8/MWh = +\$1.2/MWh	+\$1.2/MWh
3c)	Balancing market down-regulation	7% down-regulation procurement volume at 50% of wholesale price \$84.0/MWh × 0.07 × 0.5 = \$2.9/MWh	+\$2.9/MWh
3d)	Balancing market up-regulation	7% up-regulation procurement volume at 50% of wholesale price \$84.0/MWh × 0.07 × 0.5 = \$2.9/MWh	+\$2.9/MWh
4)	Ancillary service cost	Additional \$400/kVA synchronous condenser cost at 30% capacity factor See in Figure 21 Part II – Technical Deep Dives	+\$16.8/MWh
5)	Grid connection costs	Additional \$500/kW grid connection cost at 30% capacity factor See Figure 21 in Part II – Technical Deep Dives	+\$12.4/MWh
6)	Externality costs	12 kgCO_2/MWh, 15 % curtail., SCC/CO_2 price ("Social cost of carbon," 2024; Twidale, 2024) (Wikipedia, 2024): \$200–\$70/ton (\$0.20–\$0.07/kg) \$0.13/kg × 12 kg/MWh = +\$1.6/MWh → 12 kg/MWh (1 ÷ 0.85 – 1) = 2.1 kg/MWh → \$0.2/kg × 2.1 kg/MWh = +\$0.4/MWh → \$1.6/MWh + \$0.4/MWh = +\$2.0/MWh	+\$2.0/MWh
7)	Flexibility costs	Long-term value factor (capture rate) increases from 70 % to 75 % \$58.8/MWh ÷ 0.75 = \$78.4/MWh → \$78.4/MWh – \$84.0/MWh = –\$5.6/MWh	–\$5.6/MWh
=	Full system cost	Based on all the above assumptions for each cost element	\$118.1/MWh

1) – LCOE plant-level: Based on the nameplate capacity factor, the unadjusted LCOE is assumed to be $50/MWh for the VRE resource considered in this example.

2a) – Capacity factor adjustment: As the share of VRE increases, curtailment becomes more common, reducing the effective output. Non-market redispatch (Council of European Energy Regulators, 2021) to interventions by the transmission system operator (TSO) that adjust the production schedules of generating units outside the normal market mechanisms, to maintain the safe and stable operation of the power system. This may involve reallocation or commitment of synchronous generation assets, which can result in the curtailment of market-scheduled units. Other contributing factors include weather variability and declining resource availability. To account for this, the capacity factor adjustment compares the nameplate capacity factor under ideal, unconstrained conditions with the expected capacity factor under real-world conditions, including curtailment. A 85% use rate means 15% of the potential electricity is lost, increasing the cost of the remaining electricity by 18%. The adjusted LCOE is calculated by dividing the baseline LCOE of $50/MWh by 0.85, resulting in an adjusted LCOE of $58.8/MWh — a $8.8/MWh increase from the unadjusted value.

2b) – Value factor adjustment: Similar to the utilization rate, the capture rate—or value factor—measures the average revenue earned per unit of electricity relative to the market average. A value factor of 70% indicates that the electricity is sold at only 70% of the average market price. Consequently, to break even, the market price must be approximately 43% higher than the capacity factor-adjusted LCOE. Alternatively, this can be interpreted as 70% of the electricity being sold at full market value, while the remaining 30% effectively earns nothing. This reduction in revenue has a similar impact to curtailment, as electricity with no market value contributes no return. To account for this, the value factor-adjusted LCOE is calculated by dividing the $58.8/MWh capacity factor-adjusted LCOE by 0.7, yielding a new LCOE of $84.0/MWh — a $25.2/MWh increase.

3a) – Intraday selling adjustment: With current forecasting technology, VRE resources can have day-ahead forecast errors of up to 10% of the scheduled volume. This means that, on average, about 50% of the time there is a surplus of 10% that must be resold in the intraday market. In this example, we assume that the surplus electricity is sold at 80% of the day-ahead market price. The cost of this intraday adjustment can be calculated by multiplying the $58.8/MWh VRE day-ahead price by the factor, 0.1 ÷ 0.8 – 0.1, which results in a cost increase of $1.5/MWh.

3b) – Intraday buying adjustment: Forecast errors for VRE also apply to underestimations. On average, this means that 50% of the time, an additional 10% of the volume sold in the day-ahead market must be purchased in the intraday market to make up for a shortfall in VRE output. In this example, we assume that the missing electricity is bought at a 20% premium relative to the day-ahead price. The cost of this intraday adjustment is calculated by multiplying the $58.8/MWh VRE day-ahead price by the factor, 0.1 × 1.2 – 0.1, resulting in a cost increase of $1.2/MWh.

3c) – Balancing market up-regulation: As the share of VRE increases, transmission system operators (TSOs) must procure up-regulation capacity to cover potential shortfalls in VRE output. These reserves are typically not activated but are secured in advance to ensure power supply security if needed. Because they are rarely used, the price for procured reserve capacity is generally lower than the wholesale electricity price. In this example, we assume that 7% of the VRE volume sold in the day-ahead market must also be secured as up-regulation capacity in the balancing market, and that this is sold at 50% of the wholesale electricity price. The resulting cost is calculated by multiplying the $84.0/MWh wholesale electricity price by 0.1 × 0.5, which yields a $2.9/MWh increase in cost.

3d) – Balancing market up-regulation: Similar to up-regulation, down-regulation capacity must also be procured to manage potential surpluses in VRE output. These reserves are typically not activated but are maintained to ensure system stability if excess generation needs to be curtailed. Since these services are rarely used, the price for down-regulation capacity is generally lower than the wholesale electricity price. In this example, we assume that 7% of the VRE volume sold in the day-ahead market must also be secured as down-regulation capacity in the balancing market, and that this is sold at 50% of the wholesale electricity price. The resulting cost is calculated by multiplying the \$84.0/MWh wholesale electricity price by 0.1 × 0.5, resulting in a \$2.9/MWh increase in cost.

4) – Ancillary service adjustment: Ancillary service adjustments become increasingly important in high-VRE scenarios, where the grid has limited availability of synchronous resources. In systems dominated by inverter-based resources such as wind and solar, essential services like physical inertia and grid strength are no longer inherently provided. In this example, we assume that for every kilowatt (kW) of VRE capacity, one kilovolt-ampere (kVA) of synchronous condenser (SynCon) capacity is required to replace the missing services from classical synchronous generators. However, if the grid maintains a sufficient share of synchronous resources in a moderate VRE case—including nuclear, geothermal, or hydropower with adequate runtime—the need for additional SynCon capacity can be significantly reduced. However, in case this is needed, we assume the cost of new-build SynCon capacity is \$400/kVA with a 5% interest rate and a 30% capacity factor to account for operational time, losses, and operation and maintenance (DOE, 2015).

5) – Grid connection cost adjustment: VRE resources are often geographically dispersed, leading to significant variation in grid connection costs. While NREL's baseline estimate for grid connection is \$100/kW, the cost can be orders of magnitude higher for remote or offshore VRE projects. In this example, we assume a moderate scenario with a grid connection cost of \$500/kW and an interest rate of 5%. The infrastructure is assumed to operate with a 30% capacity factor, in the same range as the VRE resource it serves. However, if the grid connection is shared across a hybrid VRE system—such as a combination of solar and wind—overall utilization of the infrastructure can increase. This improved utilization can reduce the effective grid connection cost per unit of delivered electricity.

6) – Externality cost adjustment: The assumed life-cycle carbon intensity for the VRE resource is 12 kg CO_2-equivalents per MWh. Of this, \$70/ton is assumed to be covered by the carbon price determined by the market (which could be higher in the future), leaving a gap of \$130/ton to reach a social cost of carbon of \$200/ton. To account for this, the uncovered portion—\$0.13/kg—is multiplied by 12 kg/MWh, resulting in an additional cost of \$1.60/MWh. In our example, we assume 20% curtailment, corresponding to an 80% utilization rate (as outlined in the capacity factor adjustment). This means the effective carbon intensity increases by 3 kg/MWh. Applying the full social cost of carbon (\$0.20/kg) to this additional emissions intensity yields another \$0.60/MWh. Together, these two components result in a total externality cost adjustment of \$2.20/MWh.

7) – Flexibility adjustment: Flexibility can impose significant costs on consumers, but it can also enhance the value of VRE. In this example, we assume that added flexibility increases the value factor (or capture rate) of the VRE resource from 70% to 75%. This improvement reduces the value factor adjustment: dividing the \$62.5/MWh capacity factor-adjusted LCOE by 0.75 results in an adjusted LCOE of \$83.3/MWh. This is \$6.0/MWh lower than the \$89.3/MWh calculated in step 2, where the value factor was only 70%.

To understand the overall impact of VRE resources in the future power market, Figure 5 presents a stylized example of the profile-adjusted LCOE correcting for reduced capture and utilization rates. As seen, the capacity factor-adjusted LCOE increases by 18% if the utilization rate is 85%. This corresponds to a reduction in VRE capacity factor from 35% to 30%. When a VRE resource produces only 85% of what is expected, the break-even sales price for the remaining electricity is

18% higher. In addition, the LCOE must be corrected for the captured sales price. In Figure 5, a 70% value factor is assumed, implying that the market price must be 43% higher to break even. When combined with capacity factor adjustment, the value factor adjustment increases the LCOE by 50%, leading to a total profile-adjusted LCOE of 168%. Although the profile-adjusted VRE costs are cost effects at the plant level, they can significantly contribute to the full system costs. Please note that achieving the profile-adjusted cost levels shown in Figure 5 would only be possible after a substantial buildout of VRE capacity, such as those seen in Germany.

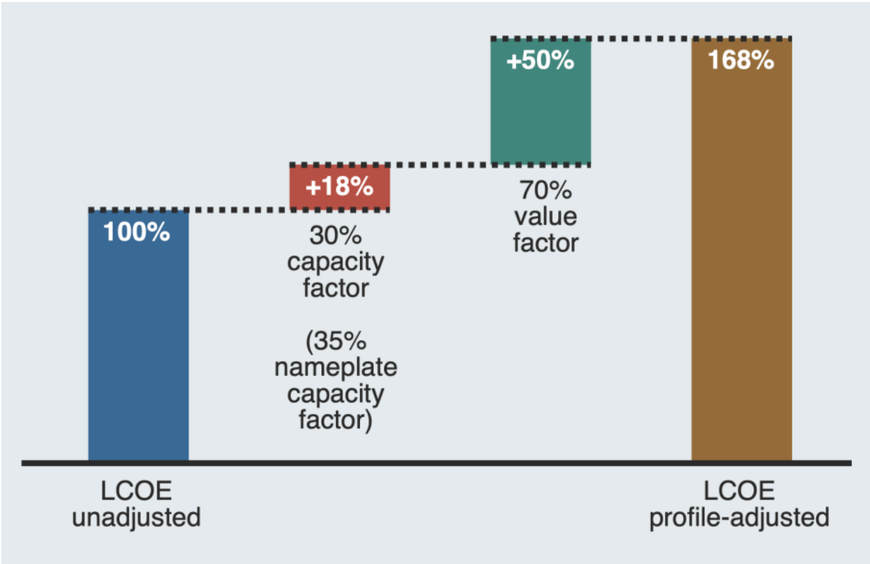

Figure 5 Stylized example of profile-adjusted VRE LCOE assuming a 85% use rate and a 70% value factor.

Figure 6 presents the sensitivity of the profile-adjusted VRE LCOE for as a function of both the use rate and value factor.

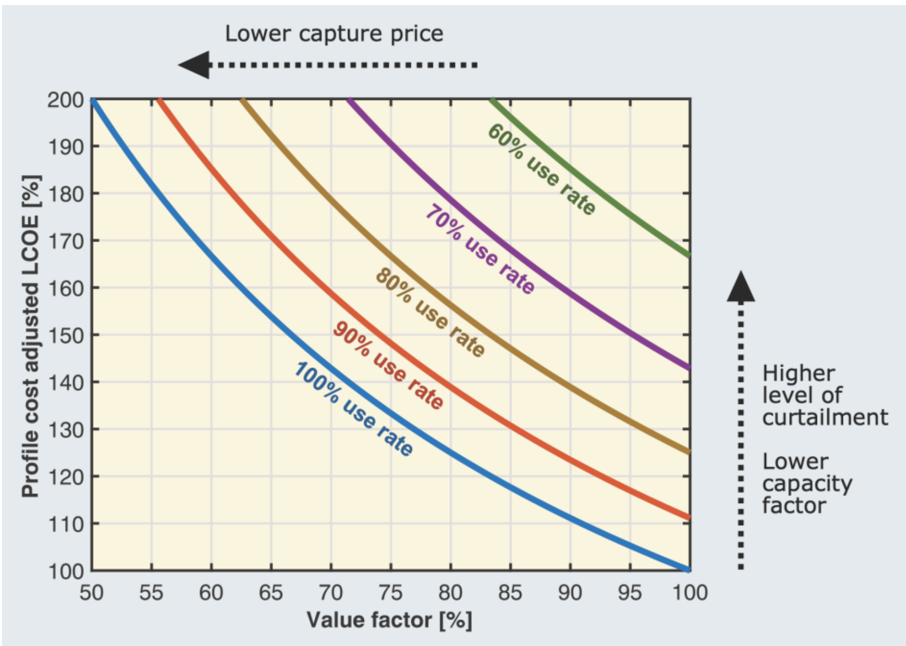

Figure 6 Normalized value factor and use rate-adjusted LCOE for VRE resources. The value factor refers to the ratio between the capture price and the wholesale electricity price, while the use rate takes into account curtailed generation or reduced energy resources leading to a lower capacity factor.

Similarly to VRE resources, there is a concern that nuclear energy will also increase its profile-adjusted costs due to more volatile electricity prices in the future power market, leading to higher curtailment levels and periodically lower sales prices. Nuclear resources are typically curtailed when the electricity price is approaching near-zero, zero, or negative. This contributes to reducing the capacity factor, but it tends to increase the sales price of the remaining power output relative to the average price of electricity. As a result, the higher profile-adjusted costs due to power curtailment will be compensated by a higher value factor of the remaining nuclear power generation, making it roughly as profitable in the future as in the present, as conceptually shown in Figure 7. This has been verified in the work of Hjelmeland *et al.* (2025). Nevertheless, please note that represents an extreme scenario where the electricity price is zero for 50% of the year, implying that the value of the electricity in the rest of the year is double as the average price of electricity, yielding a notable 200% value factor for nuclear (Nøland *et al.*, 2025).

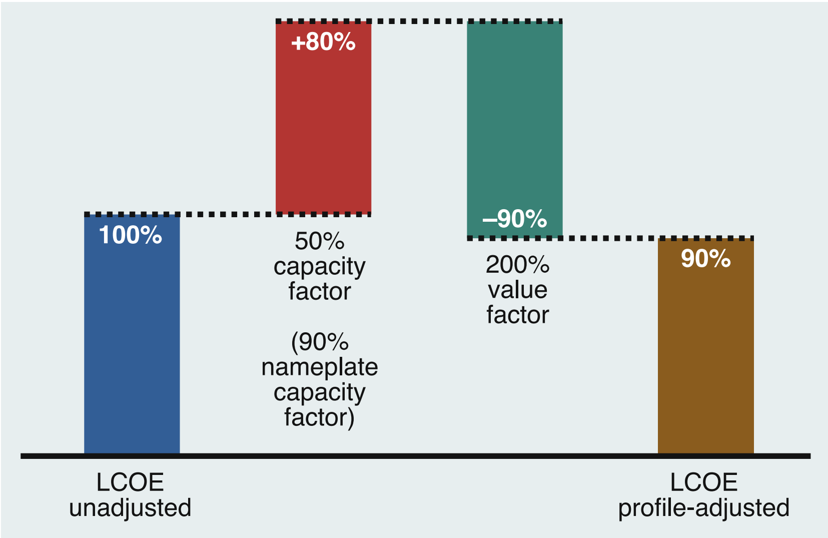

Figure 7 Stylized example of profile-adjusted nuclear LCOE with 50% a capacity factor assuming curtailment at near-zero market price with a 200% value factor for the remaining power. Unadjusted LCOE assumes a 90% capacity factor.

3 Key gaps, future modeling and conclusion

Sections 1 and 2 have identified the limitations of using simple cost metrics to assess generation options. This section turns to the far more complex models actually used by utilities, grid operators, and investors to guide decision-making. Although those models have improved steadily over time, we identify key gaps that still exist in addressing the full system costs of the electricity system. This section identifies the most critical limitations in current modeling approaches and proposes actionable solutions from a modeling perspective to support a system-level approach aligned with cost-effectiveness, resilience, and climate neutrality objectives.

3.1 Key gaps

The energy transition toward a resilient and carbon-neutral power system requires rethinking how we evaluate, design, and manage electricity markets. Electricity system modeling plays an important role in the planning and investment decisions for policymakers, grid operators, and market participants. Many current models have relied on simplified cost metrics and assumptions that do not adequately reflect real-world challenges (Mai *et al.*, 2021) (UT Austin Energy Institute, 2025). Future modeling approaches must evolve to incorporate system-wide considerations.

This report identifies the cost categories currently missing from conventional modeling approaches and highlights areas where additional analysis can offer a more complete understanding of electricity system costs and resilience. These categories are outlined below, with a detailed technical discussion provided in Part II of the report.

Power balancing: Electricity systems rely on frequency balancing services, including intraday and balancing power markets, which operate alongside the day-ahead market. Future models should incorporate the dynamics of intraday and balancing markets—accounting for forecast errors—and differentiate associated costs across various energy sources.

Non-frequency ancillary services: Non-frequency ancillary services—such as grid strength, physical inertia, and reactive power support—are critical in systems dominated by inverter-based resources (IBRs). While modern grid-forming (GFM) inverters can provide some of these services, they still fall short due to limited physical inertia and short-circuit current capabilities. As a result, costly alternatives like synchronous condensers (SynCons) may be required to ensure system reliability in a system with a low share of synchronous resources.

Grid integration: Some energy system models rely on the simplifying assumption of a "copper plate grid" (Raheel A. Shaikh *et al.*, 2023), which overlooks locational grid bottlenecks and transmission constraints. As a result, distributed generation is often modeled too optimistically without fully accounting for electrical distances, local grid limitations, and the resulting congestion costs. In particular, the grid connection costs for integrating offshore resources can be a significant contributor to the full system costs. Moreover, the costs of expanding the transmission grid—both high-voltage AC (HVAC) lines and high-voltage DC (HVDC) interconnectors—should be properly integrated into modeling practices.

Flexibility and volatility: Achieving system flexibility requires significant investments in infrastructure such as storage, demand response, interconnections, and backup generation. However, these costs are often underrepresented in current models (Anderson *et al.*, 2025). Many models assume idealized flexibility, with limited attention to real-world consumer behavior—for example, industrial users often have inflexible operational schedules, while residential and commercial consumers typically optimize for personal cost savings rather than system-wide balancing. Moreover, if flexibility solutions fail to deliver as expected, the system may become increasingly reliant on costly backup power.

Electricity price volatility—the extent to which electricity prices fluctuate over time—is a critical but often underappreciated dimension of power system planning. While models tend to emphasize cost optimization and average price levels, volatility itself can create major financial risks, reduce predictability, and undermine industrial competitiveness (Quantified Carbon, 2025).

Extreme weather events: Current modeling work often rely on historical data, failing to capture the increasing frequency and intensity of climate-induced disruptions, and their costs to society. Thus, costs related to infrastructure failures (e.g., grid damages, power plant shutdowns) and emergency responses are not well-integrated. Economic losses due to blackouts, demand spikes (e.g., heatwaves), and financial burden of winterization, flood protection and wildfire-resistant grid upgrades are not well represented in current modeling. Additionally, current models do not sufficiently capture how extreme weather in one region can strain interconnected grids and markets. Furthermore, similar risks exist for nuclear power and hydropower during extreme events. Nuclear power plants may face cooling water shortages during prolonged heatwaves and droughts, potentially leading to reduced output or shutdowns, as observed in parts of France and the U.S. Likewise, severe droughts can significantly reduce hydropower generation, causing energy deficits in regions highly reliant on it, such as Norway, Brazil, British Columbia, and California. Current models often fail to fully account for these dependencies, underestimating both direct financial losses and the need for costly backup capacity when these low-carbon firm resources become unavailable.

Energy security and defense: The susceptibility of critical infrastructure, such as subsea cables, to sabotage or geopolitical tensions introduce economic risks that are difficult to quantify. Costs associated with reinforcing them and investments in security measures, such as cyber protection, surveillance, and emergency response mechanisms are underestimated in current modeling. The reliance on critical minerals creates exposure to supply chain disruption and potential price volatility. Furthermore, the evolving landscape of international trade policies, export restrictions or resource nationalization may lead to unpredictable costs.

3.2 Modelling studies toward actionable and holistic power system planning

While recent developments in power system modeling — higher spatial and temporal resolution, operational detail, and multi-year planning — have significantly improved the realism of system cost optimization, combining all these aspects remains a major challenge. In particular, systems with a large share of variable renewables introduce complex dynamics, such as intra-hour variability, rare energy droughts, and frequency stability risks, that are difficult to fully capture within current frameworks.

Traditional cost-optimization models often focus narrowly on minimizing system cost or carbon emissions, which can oversimplify the real challenges facing future energy systems — for example, by obscuring critical uncertainties in cost assumptions and overlooking key aspects that are difficult or unrealistic to fully capture within the optimization model. Leading modeling efforts (Larson *et al.*, 2020) (Evolved Energy Research, 2024) mitigate some of these limitations by incorporating a well-designed scenario framework as well as separately highlighting beyond-cost implications (Net Zero Australia, 2023), moving towards a more holistic approach. The methodology developed in recent Quantified Carbon studies (Quantified Carbon, 2025, 2024, 2023a, 2023b) further aims to move beyond the “cost-emissions” dilemma, addressing limitations in cost representations, embracing a more holistic and multi-dimensional perspective. Rather than constraining the analysis to binary outcomes purely driven by varying input assumptions, the study explores a set of relevant technological development paths, allowing for a more nuanced understanding of strengths, weaknesses, and trade-offs.

Rather than collapsing all impacts into a single cost metric — a practice that can obscure transparency and understanding — the study presents key performance measures separately, empowering stakeholders to weigh trade-offs based on their specific priorities. The studies propose a set of quantified indicators, presented in Table 6, designed to represent the desired capabilities of future power systems. With a national-level focus, in line with the policy relevance of each country's energy sovereignty, these indicators are intended to support and inform decision-making processes by providing a structured basis for comparing alternative system pathways.

Table 6. Key evaluation dimensions and indicators for assessing future power system scenarios.

Dimension	Key indicators
Competitiveness	• Generation and capacity costs • Risk costs • Electricity price level
Energy security	• Power imports • Fuel imports • Critical materials use
Environmental & climate impacts	• Life-cycle greenhouse gas emissions • Land use
Transmission infrastructure	• Power transmission costs • Annual CO_2 captured & sequestered • Hydrogen storage capacity
Volatility and flexibility	• Electricity price volatility
Operational safety	• Firm/dispatchable capacity • Grid output levels

By structuring a comparison between the key indicators, this approach provides policymakers and stakeholders with a more accessible and actionable basis for decision-making. By covering a wider set of perspectives — competitiveness, security, climate impact, dependency on transmission infrastructure, operational safety — the study captures the complexity of building cost-effective, carbon-neutral, and resilient power systems for the future. At a glance, the following list aims to introduce the key indicators, but the reader is referred to Quantified Carbon studies (Quantified Carbon, 2025, 2024, 2023a, 2023b) for a more thorough view.

Competitiveness

- *Generation and capacity costs* is typically denoted system costs and is generally a highly relevant indicator.
- In the case of a 100% Greenfield optimisation, the average *electricity price level* equals the costs. However, this is rarely a realistic case. At the country level, electricity prices are

determined by marginal-cost pricing in power markets, which—within a capacity expansion model—are influenced by existing assets, cross-border trade, assumptions about neighboring power systems, and external factors such as fuel and CO_2 prices.
- Technology cost assumptions play a major role in the result of optimisation models. By modifying the cost assumptions post-expansion, i.e., given a certain power system scenario, to conservative levels the indicator *risk costs* highlights how much exposure a scenario has to cost increases.

Energy security

- Dependence on *power imports, fuel imports, and critical materials* highlights exposure to external actors and the associated risks of price shocks and supply disruptions.

Environmental and climate impact

- Captures *life-cycle greenhouse gas emissions*, including fuel extraction, manufacturing, operation, and decommissioning, as well as *land use* requirements for electricity production as a probe for environmental and climate impact.

Transmission infrastructure

- In different ways, *power transmission costs, annual CO_2 captured & sequestered and hydrogen storage capacity* all highlight scenarios reliance on the transmission infrastructure providing insights on deployment pace and implementation feasibility.

Volatility and flexibility

- *Electricity price volatility* of long-term price variations, for instance, the spread of quarterly average price, is a measure highlighting stability and predictability of the electricity market. Lower volatility can reduce financial risk and support long-term investment planning by making the market more attractive to investors, thus representing a crucial driver of decarbonisation.

Operational safety

- Potential *grid power output* analyses how much power can be accommodated, for instance, highlighting the required role of demand-side flexibility in the system.
- *Firm/dispatchable capacity* aims to provide how much plannable capacity is available and its role in different operational states and for system stability.

Looking ahead, further methodological improvements could be achieved by:

- Adding quantitative measures of system balancing (e.g., frequency control volumes, ancillary services needs),
- Deepening the analysis of flexibility dependence under uncertainty,
- A broader treatment of environmental externalities beyond greenhouse gas emissions including water resources and air pollution;
- Strengthening the focus on resilience against high-impact, low-probability events by incorporating performance under extreme operational conditions.
- By investigating necessary political interventions, e.g., the role of subsidies and regulated markets; and,
- Socio-economic impacts, e.g., refined decarbonisation pathways, industrial development and job creation

Rather than requiring full endogenous integration (which can become computationally prohibitive), a practical and policy-relevant approach is to build structurally distinct power system scenarios. Each scenario, defined by different technology mixes and policy choices, can be evaluated across the common set of performance indicators. This offers a transparent, robust, and uncertainty-aware foundation for guiding future power system planning.

Beyond expanding this framework, it is crucial to standardize modeling studies, including scenario design, treatment of uncertainties and probabilistic distributions, and the reporting of key indicators across the expert community. Establishing a common framework would enable transparent, consistent comparisons of power system scenarios, helping policymakers assess risks and trade-offs beyond a single cost figure and translate complex results into clear, actionable insights. Finally, further work is needed to ensure that quantitative findings are communicated effectively to policymakers, for example, by translating high critical material use into concrete, policy-relevant impacts such as supply risks or cost vulnerabilities.

As future modeling studies embrace a more holistic approach to evaluate power system pathways, they not only highlight promising development options but also identify unattractive or impractical alternatives — helping to narrow down the number of scenarios that merit deeper exploration. By systematically assessing trade-offs across multiple dimensions such as competitiveness, energy security, environmental impact, operational safety, this approach ensures a broader and more balanced foundation for decision-making.

3.3 Conclusions

Although cost metrics offer an accessible way to understand the role of technologies in power system planning, their misuse can undermine their relevance for policymaking. This study explores the topic in depth by first reviewing a range of metrics — from the widely used, producer-focused levelized cost of electricity (LCOE) to the levelized full system cost of electricity (LFSCOE), which attributes all system integration costs to each technology. Second, we introduce a novel analytical framework, System Cost Breakdown of Electricity (SCBOE), to bridge the gap between plant-level LCOE and system-level costs, by disaggregating components such as technical and economic curtailment, market capture prices, ancillary services, grid costs, externalities, and flexibility needs. We evaluate both low-LCOE variable renewables and high-LCOE firm/dispatchable resources, underscoring their respective contributions to a cost-optimal, balanced power system.

A central focus of this work is resilience. Resilience is addressed throughout the report, providing a comprehensive review on challenges such as extreme weather, energy security, cyber-physical threats, and infrastructure vulnerability — all of which are essential to future-ready modelling.

Cost-optimization modelling has advanced significantly, enabling higher spatial and temporal resolution, multi-year horizons, and greater operational fidelity. However, as systems decarbonize and VRES shares grow, new challenges emerge — including intra-hourly variability, frequency stability, and prolonged low-generation periods ("energy droughts") — that remain difficult to fully capture. In addition to resilience aspects, this work has further highlighted the need for improved modeling approaches to account for a wider spectrum of costs, including frequency and non-frequency ancillary services, grid integration costs, and flexibility options. While ongoing development efforts are closing many gaps, fully integrating all critical dimensions into optimization frameworks remains a complex task, particularly under deep uncertainty in future assumptions.

We argue that future studies must move beyond the narrow "cost-emissions" lens and adopt a more holistic, multidimensional approach. By developing a suite of quantified indicators representing the core capabilities of future power systems — including competitiveness, energy security, climate and environmental impacts, transmission needs, volatility and flexibility, and operational safety — researchers and decision-makers can better compare technology pathways, understand trade-offs, and design more informed and resilient policies.

As the current work's final conclusion, bridging the gap between advanced modeling and practical policy guidance remains a key priority, paving the way for more holistic assessments of power system pathways and more robust, informed decision-making. As modelling studies increasingly converge on which capabilities (here represented by quantified indicators) should be considered in power system planning, they lay a strong foundation for developing efficient market designs capable of driving a successful decarbonisation of the electricity system.

Part II: Technical deep dives

Building upon the foundation laid in Part I, which outlined the policy context, objectives, and key challenges in achieving a resilient, carbon-neutral electricity system, Part II serves to bridge those high-level insights with detailed technical analysis. Part I highlighted how conventional planning and cost metrics often overlook critical factors - from integration costs and grid stability to ancillary services and extreme-event preparedness – that are essential for reliable, sustainable power systems. It established the need for a holistic approach to power system modeling, emphasizing resilience, comprehensive cost accounting, and informed policy design. Part II directly builds on these themes by delving into those once-overlooked aspects: it provides in-depth examinations of resilience definitions, system flexibility, balancing and ancillary services, grid constraints, demand-side management, extreme weather impacts, security considerations, environmental trade-offs, and technology readiness.

The section begins with an in-depth examination of resilience, highlighting definitions—such as reliability, robustness, and resilience—and their implications for effective policy-making and system operations. It stresses the necessity for clear, shared definitions to facilitate coherent strategies and robust infrastructure planning.

Section 2 provides a contextual background of the development of cost optimization modelling.

The technical deep dives further explore frequency balancing services, analyzing intraday and balancing power markets, which are essential in managing forecast errors and real-time balancing needs. Detailed insights are provided into non-frequency ancillary services including physical grid inertia, grid strength, and voltage regulation, emphasizing the critical roles of technologies such as synchronous resources, synchronous condensers, and grid-forming inverters.

The report critically discusses the "copper plate grid" assumption commonly used in simplified system modeling, underscoring the significance of accurately considering grid connection costs, transmission constraints, and infrastructure needs, especially with geographically dispersed VRE resources. Additionally, the importance of demand-side flexibility is highlighted, with an acknowledgment of real-world limitations and the potential risks of overestimating flexibility in energy models. A substantial portion of 100% renewable system studies (Wang, 2023) particularly for Asia and Africa, relies on overly simplified models, most notably the LUT Energy System Transition Model. These studies often use unrealistically low cost assumptions for technologies across all regions, omit critical system components like reserve margins and transmission constraints, and rely heavily on speculative solutions such as renewable synthetic methane or large-scale biomass. Operational challenges, sub-hourly balancing, and alternative decarbonization scenarios (e.g. with nuclear or CCS) are largely ignored. Many works are near-duplicates, differing only in geography, which amplifies the influence of flawed assumptions. These limitations make such models unsuitable for robust policy-making or real-world system planning.

Extreme weather events are analyzed with historical context and the increasing frequency due to climate change, underscoring the necessity for resilient infrastructure and strategic planning to mitigate potential severe disruptions and associated costs. Security considerations address geopolitical risks, the vulnerability of critical infrastructures, and cybersecurity threats.

Environmental and social impacts are also detailed, including lifecycle environmental assessments and trade-offs between system resilience and environmental protection. The discussion extends to technology readiness level risks, evaluating the maturity and deployment readiness of grid-forming inverter technologies, battery and hydrogen storage, and nuclear reactor technologies, stressing the importance of realistic risk assessments in future energy system modeling.

1 Resilient energy system

While first introducing the concept of resilience, this section furthermore addresses the lack of a universally accepted definition of power system resilience and its implications for policy and operational standards. It discusses how these inconsistencies can hinder comprehensive planning and implementation strategies.

1.1 Different definitions and lack of consensus

1.1.1 Varying concepts describing power systems

When discussing the future of power systems, terms like reliability, resilience, robustness, and adequacy are often used interchangeably, which can lead to confusion. These terms describe different aspects of how energy systems perform under normal conditions and during disruptions. Misunderstanding these distinctions can result in unclear communication and even flawed decision-making in planning or operation. By establishing a clear and shared understanding of this terminology, we can ensure more effective discussions and better solutions for the challenges ahead.

The scientific literature makes a clear distinction between these concepts. Accordingly to Zissis (Zissis, 2019), "reliability is the probability that a system will perform in a satisfactory manner for a given period when it is used under specified operating conditions", whereas the "robustness is the ability of a system to avoid malfunctioning when a fraction of its elements fail, or the ability of a system to perform the intended task under unexpected disturbances" (Koç *et al.*, 2014) While, resilience is a system's ability to withstand, adapt, and absorb from a major disruption within acceptable degradation parameters and recover within a satisfactory timeframe" (Ahmadi *et al.*, 2022). As per Wang, Kapur and Reed (Wang *et al.*, 2014) and Beyza & Yusta (Beyza and Yusta, 2022) these three terms currently referred to as "R3 concept" can be presented as in Figure 8. Reliability, resilience, and robustness share the fundamental goal of ensuring the continuity of a system's performance under varying conditions. All three concepts address the need for systems to maintain functionality and serve their intended purpose, even when faced with challenges or disruptions. They emphasize the importance of designing and operating systems that can provide consistent service (reliability), resist failures (robustness), and recover from disruptions (resilience).

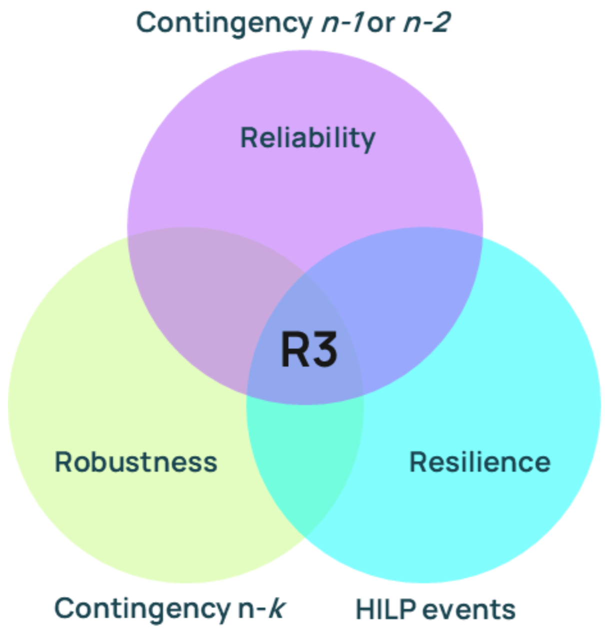

Figure 8 The R3 concept visualized through Venn diagram[2].

The relationship between reliability and resilience is illustrated in Figure 8. Despite their overlaps, each concept focuses on distinct dimensions of system performance, contributing to a holistic approach to system design and evaluation. The Figure 9 presents a probability-impact matrix with four quadrants, distinguishing between different types of events in power systems. The vertical axis represents probability, increasing from bottom to top, while the horizontal axis represents impact, increasing from left to right.

High probability – low impact (reliability domain): These events occur frequently but cause only minor disruptions, such as small voltage fluctuations or minor equipment failures.

High probability – high impact: These events are both frequent and severe, requiring robust system resilience to manage potential widespread disruptions.

Low probability – low impact Rare and minor disturbances, which typically do not pose significant challenges to the system.

High impact – low probability (resilience domain) These events, often referred to as High-Impact, Low-Probability (HILP) events, include natural disasters, cyberattacks, or cascading failures. While rare, their consequences can be catastrophic, necessitating resilience strategies.

[2] N-1 event: The failure of a single component (e.g., a transmission line, generator, or transformer) in the power system, with the system expected to withstand the failure without losing stability or violating operational limits. N-2 event: The simultaneous failure of two components, which is less common but can have more severe impacts on system reliability compared to N-1 events. N-k event: A more generalized contingency where *k* components fail simultaneously, representing extreme or cascading failures that can significantly disrupt the power system. HILP (High-Impact, Low-Probability) event: Rare but severe events, such as natural disasters, cyberattacks, or large-scale blackouts, that can cause major disruptions despite their low probability of occurrence.

Such classification highlights the importance of both reliability, which focuses on minimizing frequent small disruptions, and resilience, which addresses the ability to recover from large-scale, rare events.

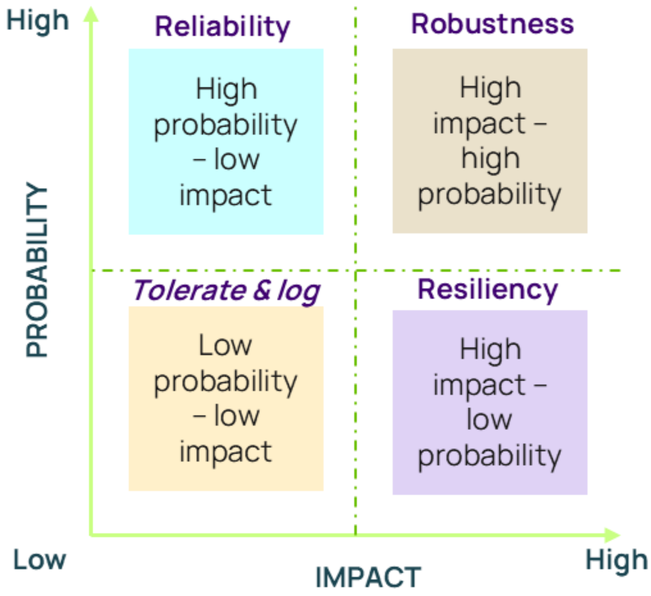

Figure 9 Relationship between reliability and resilience.

Resource adequacy on the other hand as defined by Federal Energy Regulatory Commission (FERC) (Moeller *et al.*, 2013) is: "To maintain reliable operations, electric systems must maintain sufficient capacity resources to peak load requirements plus a planning reserve margin." Whereas, in the report (THEMA Consulting Group & Norden, 2015) by Norden it is defined as: "Capacity adequacy is the system's ability to establish market equilibrium in the day-ahead market, and at the same time provide adequate balancing resources for real-time operation, even in extreme situations." Clearly the later does not only focus on the peak load hours but is concerned about the energy market ability to match the demand and supply not only on a day-ahead but also on a real-time operation basis. The focus of adequacy is the availability of sufficient resources to meet demand over different time horizons. While traditional adequacy assessments focus on generation adequacy—ensuring sufficient generation capacity to meet demand—transmission and distribution adequacy address whether the infrastructure can reliably deliver electricity from generators to consumers. Transmission and distribution adequacy often complement generation adequacy. Even if generation capacity is sufficient, inadequacies in the transmission and distribution infrastructure can: limit the delivery of electricity to where it is needed; cause localized or system-wide reliability issues; impede the integration of renewable energy or new loads, such as electric vehicles. Table 7 provides a distinction between the concepts of reliability, resilience, robustness, and adequacy and how they address different dimensions of power systems.

Table 7. Overview of different terms used.

Term	Focus	Key metrics	Scope	Example
Reliability	Consistency in normal operations – short run	SAIDI, ASAI	Operational, most caused by failures on the distribution system	Preventing frequent outages during normal weather conditions
Robustness	Strength under stress	Stress tests, fault tolerance	Structural design	Withstanding physical stress, such as a storm without major service loss
Resilience	Response and recovery from extreme events	Recovery time, outage duration	Extreme events	Rapidly restoring power after a hurricane, extreme weather and environmental conditions, or cyberattack
Adequacy	Capacity to meet demand – long run	LOLE, Reserve margin, capacity factor	Planning and operational planning	Ensuring sufficient generation to meet peak demand in future years. Further, with VREs, meeting the energy needs 24 x 7, 365 days a year.

SAIDI: System average interruption duration index (World Bank Group, 2025); ASAI: Average service availability index; LOLE: Loss of load expectation (Glowacki Law Firm, 2024)

Summarizing Table 7, the reliability, robustness, resilience, and adequacy span both time and stress dimensions in power system planning and operation. Reliability ensures consistent performance in the short run, preventing frequent outages under normal conditions. Robustness strengthens the system's ability to withstand foreseeable stresses, such as storms, without major failures. When extreme events occur, resilience determines how quickly and effectively the system can recover and adapt (e.g., post-hurricane restoration, extreme temperature events). Meanwhile, adequacy focuses on the long run, ensuring sufficient capacity and energy to meet future demand through proper infrastructure and resource planning. Consequently, these concepts should be considered sequentially—and across different time horizons, from very short-run operational stability to very long-run system adequacy.

Quantifying resiliency is not straightforward. As expressed by Jackson and Fitzgerald (Jackson and Fitzgerald, 2016) "a system cannot simply be said to either be resilient or not but may be said to show some characteristics of resilience in response to a certain set of faults or attacks under certain circumstances." Concerning the above, any metric is event specific and resiliency can be presented as a process as shown in Figure 10. It illustrates resilience as a dynamic time-based process rather than a static property. The vertical axis represents system function, while the horizontal axis represents time. The figure outlines the system's response to a critical event, depicting different phases of resilience:

Anticipate: Before the event, the system prepares by identifying potential threats and taking preventive measures. Survive: During the event, the system experiences a functional decline but remains operational at some level. Sustain: The system stabilizes at a lower performance level while coping with the impact of the disruption. Recover: After the event, efforts are made to restore system function, leading to an upward trend. Adapt: Lessons learned from the event help improve future resilience, potentially leading to a more robust system. Anticipate (again): The cycle continues as the system integrates new strategies to prepare for future challenges.

This visualization is crucial because it emphasizes that resilience is not merely about avoiding failures but also about how a system responds and adapts to disruptions. It aligns with the idea that resilience cannot be assessed by a single metric but rather by evaluating how a system anticipates, withstands, recovers from, and adapts to disturbances over time. By recognizing resilience as a process, decision-makers can develop strategies that enhance both short-term recovery and long-term adaptability in power systems.

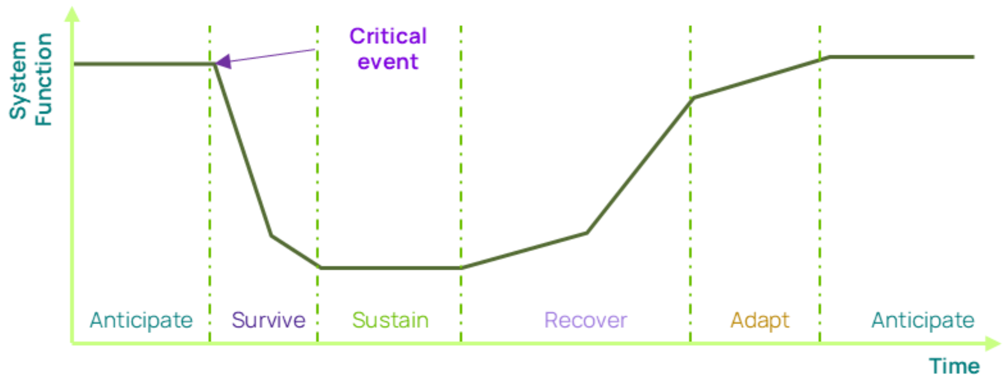

Figure 10. Resilience as a process.

Building on the conceptual foundation of resilience curves, recent efforts by NERC and NATF have advanced the practical quantification of the resilience trapezoid by identifying key phases—prepare, absorb, adapt, and recover—that span planning, operations, and recovery timescales (NorthAmerican Transmission Forum and EPRI, 2022). These phases form the basis for assessing and improving transmission system resilience through investments such as hardening infrastructure, enhancing redundancy, and incorporating adaptive strategies. Mishra *et al.* provide a comprehensive review of these resilience-enhancing measures, including smartening the grid, integrating distributed generation, and building resource-efficient infrastructure, and emphasize that resilience must be integrated at multiple levels of system design (Mishra *et al.*, 2024). Meanwhile, Li and Mostafavi demonstrate through empirical analysis that resilience curve archetypes—particularly triangular and trapezoidal forms—can be identified across hundreds of outage events using unsupervised machine learning (Li and Mostafavi, 2024). Their work confirms that real-world power systems exhibit distinct resilience behaviors, such as sustained degradation before recovery or linear bounce-backs, which are directly influenced by prior investments and system design. Together, these findings show that resilience trapezoids are not just theoretical tools but measurable phenomena that can guide strategic, data-driven investments in power system infrastructure.

In summary, while resilience is often viewed through the lens of grid operations and outage recovery, it is equally important in system-level modeling—particularly when planning for uncertain futures shaped by climate change, renewable variability, and extreme events. Rather than standing apart from robustness and adequacy, resilience offers a process-based perspective that enhances long-term decision-making. By integrating resilience into power system models, planners can assess not just how systems operate under stress, but how they evolve, recover, and adapt. This ensures that capacity expansion, resource mix, and flexibility strategies are not only robust and adequate, but also responsive to the unpredictable and compounding nature of future challenges.

1.1.2 Impact of definition disparities on policy and implementation

Varying definitions of resilience in power systems create significant challenges in policymaking, planning, and operational practices. Without a clear consensus, stakeholders may struggle to align goals, evaluate performance, and implement effective solutions. This lack of uniformity affects multiple areas including, for example, misaligned goals as outlined in (Michael Craig, 2021). Craig has shown that policies may focus on certain aspects, such as reliability or robustness, while overlooking critical resilience measures. For example, policies aimed solely at minimizing outage frequency might neglect recovery capabilities following extreme weather events. A report issued by the Department of Energy (U.S. Department of Energy (DOE), 2013) shows how the resources might be allocated to projects that meet short-term reliability goals but fail to enhance overall resilience, as seen in responses to Hurricane Sandy. The report highlights that focusing on short term goals resulted in temporary fixes without infrastructure upgrades. Substations that flooded during Hurricane Sandy were repaired but not redesigned to prevent future inundations, missing an opportunity to incorporate storm-hardening measures such as elevation or waterproofing. The DOE's report underscores that while short-term recovery is critical for mitigating immediate harm, it should not come at the expense of long-term resilience. By integrating resilience considerations into recovery efforts, utilities and policymakers can build infrastructure that is better equipped to handle future disruptions. Another critical event namely the Hurricane Maria in Puerto Rico resulted in a very long recovery time that has highlighted a lack of resilience-centered planning. While the grid was designed for reliability, its limited robustness and recovery mechanisms led to significant delays in restoration (Chandler, 2017).

The above presented examples underscore the critical distinction between short-term recovery efforts, which focus on immediate restoration, and long-term resilience measures, which aim to enhance system adaptability and robustness against future disruptions. Effective resilience planning requires a balanced approach that not only restores functionality quickly but also integrates long-term improvements to mitigate the impact of future extreme events. In the context of power system design, this means incorporating resilience considerations into asset siting and sizing, ensuring redundancy in transmission paths, selecting robust and adaptable technologies (e.g., grid-forming inverters or underground cables), and designing for modularity and flexibility. For example, a resilience-informed planning process may prioritize co-optimizing storage and distributed generation near critical loads, or investing in infrastructure that enables sectionalizing and islanding during widespread outages. These choices enhance not just recovery but also future-proof the system against evolving threats.

1.2 Scope of resilience in this report

In line with the above discussion and the scope of this report, resilience in the context of a resilient and carbon-neutral power system can be defined as: *Resilience is the ability of a power system to* *anticipate, withstand, adapt, and recover from disruptions, whether caused by extreme weather, cyberattacks, or other major disturbances, while maintaining essential functionality and minimizing service interruptions.*

In practical terms, this definition informs not only emergency response strategies but also long-term power system design. Resilience shapes how infrastructure is sited, hardened, and interconnected—such as elevating substations in flood-prone areas, using underground cabling where wind damage is likely, or designing meshed network topologies that provide alternative supply paths. It also motivates the inclusion of flexible resources, like storage, demand response, and microgrids, which enhance both the ability to maintain service during disruptions and to recover rapidly afterward. As power systems transition to high shares of renewable energy, resilience becomes increasingly tied to the use of technologies that can stabilize the grid without relying on synchronous inertia, such as grid-forming inverters and automated reconfiguration systems.

From a power system modeling perspective, resilience is operationalized by explicitly incorporating the ability to respond to uncertainty, stress, and shocks within simulation and optimization frameworks. This may involve modeling low-probability, high-impact scenarios—such as multi-day wind droughts or cyber-physical threats—within capacity expansion or resource adequacy studies. Modeling frameworks can assess how quickly a system can recover following a disruption and evaluate the effectiveness of design alternatives under stress. Approaches such as stochastic programming, robust optimization, and dynamic simulations across multiple timescales allow planners to compare not only economic efficiency but also resilience outcomes. Resilience metrics such as expected energy not served, loss-of-load probability, or degradation and recovery trajectories are increasingly being integrated into model outputs to evaluate system performance beyond average-case scenarios.

2 A general perspective of the development of cost optimization modelling

Early power system modeling studies were often highly simplified, emphasizing lowest-cost capacity expansion to meet an aggregate load with minimal detail (Helistö *et al.*, 2019). These first-generation models typically operated at coarse spatial and temporal granularity – for example, representing an entire grid with a single node and using load duration curves or a few time slices to approximate annual demand variability. Such simplifications kept computations feasible but overlooked the variability of emerging renewable sources. As a result, low-resolution models could not achieve the optimal generation mix, often over/under-investing in inflexible baseload capacity and under/over - estimating the need for peaking and storage flexibility (Helistö *et al.*, 2019). Likewise, aggregating systems into very few regions (low spatial resolution) or using only a handful of representative days could yield less reliable planning results in particular in the light of power system long-term resilience and power adequacy.

These limitations were exposed with rapidly growing shares of solar and wind generation. As their inherent variability and uncertainty made it difficult to balance supply and demand with simplistic models (Deng and Lv, 2020). In response, researchers began incorporating finer time steps and more grid detail into optimization studies. For instance, Helistö *et al.* show that using only a few representative days is not sufficient to determine an optimal generation portfolio, and that incorporating operational constraints (like ramping and reserves) produces more realistic total system cost estimates (Helistö *et al.*, 2019). Consequently, by the late 2010s the community widely recognized the need for higher spatial and temporal resolution in capacity expansion models. There is now much greater interest in capturing operational aspects – such as unit ramping capability or reserve procurement, – even at the planning stage (Helistö *et al.*, 2019). Established energy system optimization frameworks of earlier decades, like the MARKAL/TIMES family and MESSAGE, have also evolved over this period. As they were originally designed for multi-decade scenario analysis with relatively simple temporal detail, but have since been extended to better represent short-term variability and policy targets as the energy landscape changed (Fodstad *et al.*, 2022). In summary, the global trend shifted from a single-region, models toward more granular (spatial and temporal) representations that acknowledge the temporal variability of renewables and the geographic diversity of resources (physical potential as well as resource availability itself) in order to accurately optimize system costs under high renewable penetration.

Today's state-of-the-art power system models improved spatial and temporal resolutions, multi-year investment planning horizons, and enhanced operational detail all while integrating policy objectives. Many studies now deploy high-resolution models that simulate large interconnected grids with hourly (or sub-hourly) time steps over an entire year (or multiple years), capturing the nuances of weather-driven renewable output and transmission constraints. Open-source frameworks like PyPSA (Python for Power System Analysis) exemplify this advance: PyPSA allows co-optimizing generation and transmission investments together with unit commitment–style operational dispatch over multiple periods, and it scales to continental networks with long time series (Brown, 2018).

Such tools bridge the gap between traditional capacity expansion planning and production cost modeling by optimizing both investment and operation within a unified model. At the same time, multi-period (multi-year) modeling has become standard in planning studies. Models based on frameworks like MESSAGE and TIMES simulate the evolution of the power system over decades, with sequential investment stages, thus enabling an analysis and examination of long-term transition pathways under technology cost trajectories and end-of-lifetime of the individual units (Huppmann *et al.*, 2019). This multi-year scope is often combined with policy and climate constraints. Modern optimization studies routinely include carbon budgets, renewable portfolio standards, or other policy targets as explicit inputs, reflecting the influence of international agreements and national plans on system design. For example, the MESSAGEix framework (a successor to MESSAGE) now provides an open platform for integrated analysis of energy systems under climate policy scenarios and has been used to inform IPCC assessments (Huppmann *et al.*, 2019). In such models, operational complexities are deeply embedded: planners account for reserve margins, ramp-rate limits, unit commitment, storage dynamics, and sector coupling (e.g. power, heat, and transport) within the optimization (Helistö *et al.*, 2019).

Accurately capturing the growing influence of weather variability and extremes is a key challenge in power system planning, particularly as renewable energy sources and electrified heating and cooling become more dominant. A range of studies emphasise the importance of using representative time periods, long-term weather datasets, and probabilistic modelling of extreme events to reflect system stress and uncertainty more realistically. Methods such as clustering and scenario sampling have been developed to balance computational efficiency with the need for chronological consistency in natural inflows and demand patterns. Without such sophistication, models risk underestimating investment needs and system vulnerabilities, especially during rare but critical conditions. As a result, incorporating multi-year weather scenarios and interdisciplinary approaches has become increasingly essential for developing resilient and cost-effective capacity expansion strategies.

The increased level of detail in the cost optimisation modelling aims to ensure that the proposed capacity mix is not only cost-optimal, but also practical, feasible, and reliable under real-world conditions. Recent review studies combine these trends, noting a clear movement toward higher temporal detail, cross-sector and network coupling, and improved treatment of uncertainty and flexibility in energy modeling (Fodstad *et al.*, 2022). In conclusion, the field of power system modeling has globally progressed from simplistic, isolated least-cost analyses to sophisticated, integrated optimization frameworks.

While the evolution of power system modeling toward higher spatial and temporal resolution, multi-year planning, and operational detail has significantly improved the realism of system cost optimization, combining all these aspects remains a major challenge — especially in systems with large shares of variable renewable energy sources. High VRES penetration introduces complex dynamics such as intra-hourly variability, frequency stability issues, and rare but critical events like periods of low wind and solar PV generation (energy droughts), which are difficult to fully capture. Moreover, achieving realistic modeling across wide spatial areas requires balancing computational capability with the need for detailed grid representations, sector coupling, storage flexibility, and uncertainty modeling. As a result, despite substantial advances, current models still face trade-offs between resolution, scope, and computational feasibility, particularly when trying to anticipate and manage extreme conditions and system resilience under deep decarbonization scenarios (Fodstad *et al.*, 2022) (Oikonomou *et al.*, 2022). In addition, many models rely on stylized assumptions of frictionless investment and perfect coordination, overlooking real-world constraints such as permitting delays, supply chain limitations, workforce capacity, and public acceptance. For power system planning to support actionable and resilient policy, future modeling must better reflect these systemic risks, uncertainties and implementation barriers (Carpignano *et al.*, 2011).

3 Frequency balancing services

This section focuses on the future costs of frequency-related balancing services—specifically the balancing and intraday power markets—which complement the day-ahead market but are often poorly represented or entirely overlooked in current energy system models (Haugen *et al.*, 2024). Balancing costs are dynamic and depend on factors such as the generation mix, market maturity, and how these evolve over time. Table 8 outlines the various power markets required to maintain the instantaneous balance between electricity supply and demand.

Table 8. Different power market definitions.

Day-ahead (DA) power market	Intraday (ID) power market	Balancing power market
Market clearing 12 to 36 hours before delivery with a time resolution of 15 to 60 minutes	Market clearing 5 to 30 minutes before delivery with a time resolution of 15 to 60 minutes	Market clearing 5 to 15 minutes before delivery with a real-time balancing resolution

3.1 Intraday power market

The intraday (ID) power market is a short-term wholesale power market responsible for the continuous trading of electricity throughout the day and allows its participants and the balancing responsible parties (BRPs) to adjust their position to trade electricity closer to real time. Power balancing occurring in the intraday market reduces the volume and size of the balancing power (BP) market (Pape *et al.*, 2016). Therefore, the relative difference between these two markets should be seen in relation to each other. Balancing in the intraday (ID) market is generally cheaper than in the balancing power (BP) market because market participants can make more accurate adjustments as updated forecasts reduce uncertainty closer to real time (Jantunen, 2023). The BP market, which corrects the remaining imbalances, often involves more costly measures since it's the last line of defence for system stability. The same applies to the total system load. In Europe, the ID market is open 24/7, 365 days per year, offering 15-, 30-, and 60-minute resolutions for trading, depending on the region (NEMO Committee, 2022). Figure 11 highlights the recent developments in two major ID markets in Europe. Both markets have seen an increase in re-trading volume over the years, especially after 2020, with the European Power Exchange (EPEX SPOT) experiencing a more drastic rise. The development highlights the increasing need for real-time adjustments.

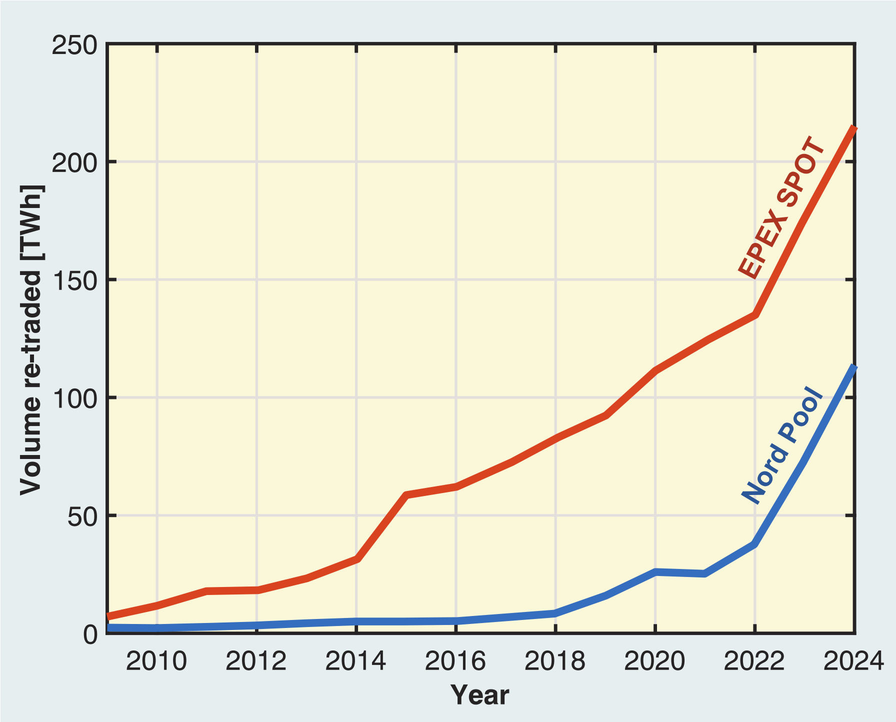

Figure 11. Intraday market re-trading volume for EPEX SPOT and Nord Pool between 2009 and 2024.

In 2023, 717.8 TWh were traded on EPEX SPOT (EPEX SPOT, 2024), whereas 542.1 TWh in the day-ahead (DA) market, and 175.7 TWh in the intraday (ID) market. Consequently, the volume of the ID market was 32.4 percent of the DA market in the largest European market. Compared to 2022, the ID market has experienced a 30.5 percent growth. The ID market experiences more price volatility than the DA market (Priyanka Shinde and Mikael Amelin, 2019), but there are, on average, no significant price premiums in the ID market (Hu *et al.*, 2021). This is because VRE price cannibalization due to VRE over-production tends to balance out the cost penalty of VRE shortfall. The dynamics is similar to the DA market. When the actual VRE production is larger than its forecast, market participants are willing to pay a lower electricity price on the ID market compared to the price of the same electricity in the DA market and vice versa when the VRE production is lower (Hu *et al.*, 2021). As a result, additional VRE will be cannibalized in the ID market relative to the DA market. This comes in addition to the existing cannibalization that might have already occurred in the DA market, which is accounted for in the profile cost adjusted LCOE. VRE surplus bids are generally lower in the ID market relative to the DA market (Johanndeiter and Bertsch, 2024). Similarly to the DA market, less VRE output than expected in the ID market leads to higher ID market prices for allocating the power to fill in the gap.

The ID market can reduce VRE forecast uncertainty and bidding errors in the DA market. Depending on the weather region and the level of forecast error penalties, the amount of VRE re-traded in the ID market can vary between 10 and 30 percent of its initial volume in the DA market. Improved modeling reducing forecast errors can lead to reduced shares of the ID market and lower the price difference between these markets. It will also reduce the cost penalty of VRE with respect to the mismatch in planned delivery.

Figure 12 illustrates how the ID market-adjusted LCOE is affected by ID price cannibalization, depending on the volume of VRE re-trading—both from selling surplus generation and purchasing to cover shortfalls. The analysis assumes an equal split between over- and under-production of VRE. Under the assumption of no price premium in the ID market, higher prices during shortfalls offset lower capture prices during periods of overproduction. Half of the re-trading reflects revenue loss from selling surplus VRE at lower prices, while the other half represents additional costs incurred from buying power to make up for VRE shortfalls—a cost penalty for imbalance. Since the ID market is smaller than the day-ahead (DA) market, the resulting LCOE adjustments from cannibalization are smaller than the profile-adjusted costs observed in the DA market, as shown in Figure 12. Please note that the ID market adjustment comes in addition to prior adjustments due to power curtailment and price cannibalization in the DA market.

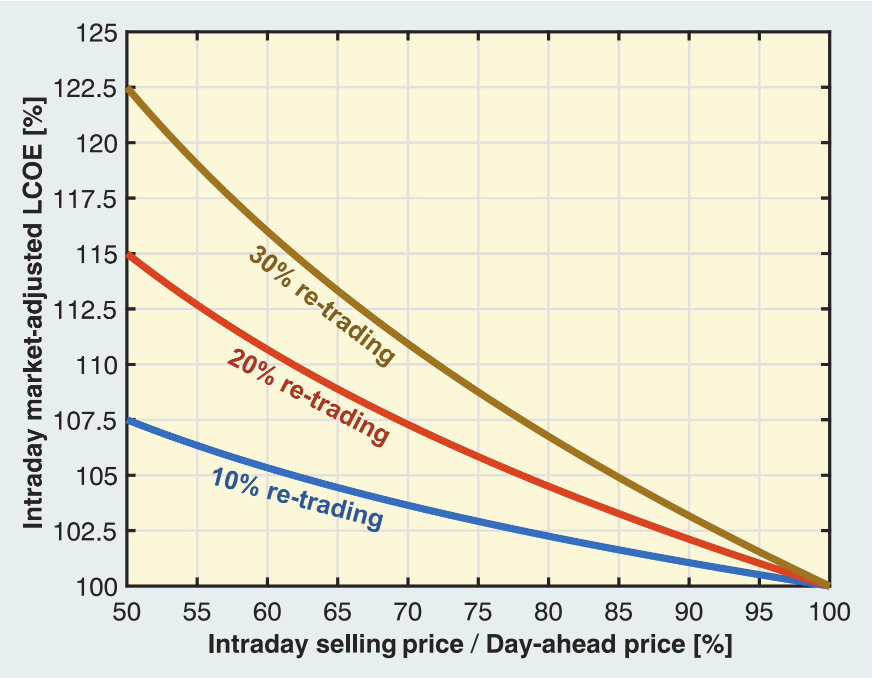

Figure 12. Intraday market-adjusted LCOE for VRE resources as a function of ID selling price due to VRE surplus price cannibalization and re-trading volumes, assuming equal amounts of over- and under-production and zero average price premium between ID and DA markets.

3.2 Balancing power market

The balancing power (BP) market is an institutional arrangement required to continuously balance the supply and demand of electricity to ensure frequency stability. The normalized balancing costs tend to be levelized over the total generation and are not associated with specific energy technologies. This subsection will describe how the following balancing services need to be taken into account for the specific impact of VRE sources. Figure 13 illustrates a stylized example of a balancing power market response after a disturbance, including different balancing products (ENTSO-E, 2024).

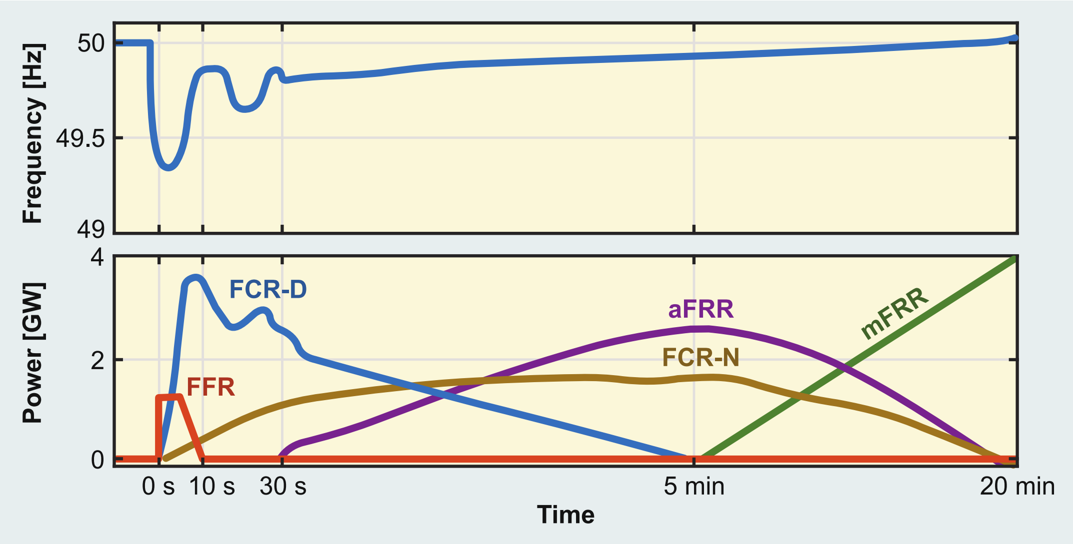

Figure 13. Stylized balancing power market response dynamic after a disturbance, highlighting different products.

Procured tertiary volumes of balancing power (mFRR) in megawatts (MW) can be calculated in megawatt-hours (MWh) since the capacity has to be available for one hour. In the VRE-rich region of Denmark, the BP market price for balancing wind power was $3 to $4 per MWh between 2013 and 2018 (Soini, 2021). A more recent example of balancing products and costs is shown in Table 9, representing the Swedish balancing market in 2024. To put the numbers in context, the total VRE capacity was 21 GW, with 17 GW of wind power and 4 GW of solar power, which generated 42 TWh. The deployed VRE resources can be considered as one of the major contributors to newly allocated secondary and tertiary reserves (aFRR and mFRR) over the last couple of decades resulting from VRE buildouts. By simplifying the calculation and allocating all these costs to their generation, the VRE balancing cost in Sweden was roughly $5/MWh, which represents an upper estimate as some secondary and tertiary volumes were established already prior to the VRE deployment. Nevertheless, it is in a similar range as calculation in the illustrative case study in Part 1 of this report and similar to the value reported in Denmark (Soini, 2021).

With a total procured secondary and tertiary reserve volume of 8.6 TWh (aFRR and mFRR), it represents one-fifth of the total VRE generation in 2024. Assuming that all of these reserves are allocated to VRE deployments and considering that both reserves are separated by upward and downward regulation, it approximates an average dimensioning forecast error of ± 10 percent. This is the medium case of Figure 14, which presents a balancing market-adjusted LCOE as a function of the balancing market price. Since balancing is mostly related to the procurement of capacity reservation while there is some energy activation, the balancing price is typically a fraction of the day-ahead price, $23.5/MWh in the 2024 case. Activated volumes are much more expensive but exhibit an insignificant share of the balancing cost and are usually not covered by the TSO but by the producer responsible for the incident of balancing market activation of procured volumes.

The allocation of balancing reserves and products varies significantly between countries. As shown in Figure 15 balancing costs in Norway have continued to rise since 2022, despite falling electricity prices and limited domestic deployment of VRE. Part of this increase may be attributed to the need to balance imported VRE electricity from neighbouring countries. The dimensioning of balancing products is determined by the TSO, who may consider incurring higher costs to strengthen energy security in an increasingly complex and interconnected power grid.

Table 9. Case study of reserve products cost and supply in Sweden's 2024 balancing power market (Svenska Kraftnät, 2024). Assumed currency exchange rate is 11 SEK/ $.

Market	Primary reserves			Secondary reserves		Tertiary reserves		FFR
	FCR-D ↑	FCR-D ↓	FCR-N	aFRR ↑	aFRR ↓	mFRR ↑	mFRR ↓	
Total cost	$66 M	$103 M	$119 M	$19 M	$19 M	$82 M	$82 M	$1 M
Volume	5.0 TWh	3.6 TWh	2.0 TWh	0.8 TWh	0.8 TWh	3.5 TWh	3.5 TWh	0.1 TWh
Avg. price	$13/MWh	$29/MWh	$58/MWh	$24/MWh	$24/MWh	$23/MWh	$23/MWh	$10/MWh
Avg. supply	570 MW/h	411 MW/h	235 MW/h	91 MW/h	91 MW/h	399 MW/h	399 MW/h	11 MW/h
Max. supply	570 MW/h	411 MW/h	235 MW/h	106 MW/h	111 MW/h	630 MW/h	750 MW/h	105 MW/h
Cap. factor	100 %	100 %	100 %	86 %	86 %	63 %	53 %	10 %

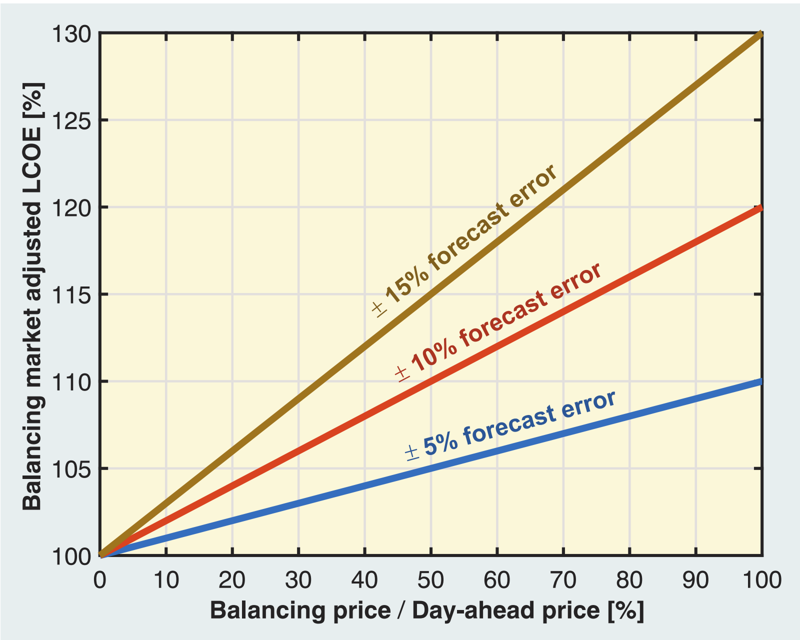

Figure 14. Balancing market adjusted LCOE for different dimensioned VRE forecast errors with an average balancing price relative to the day-ahead price, both accounting for capacity reservation and energy activation.

3.2.1 Primary reserves – frequency containment reserves (FCR-D & FCR-N): These are automatically controlled reserves based on the frequency deviation and full activation at 49.5 Hz. The dimensioning reference for the FCR-D disturbance reserve is the dimensioning shortfall of the single largest generation unit (i.e., a nuclear power plant) in the upward direction and the largest full export interconnector unit in the downward direction. Additionally, the FCR-N normal reserve is dimensioned based on historical imbalances in the power system and responds slower than the FCR-D.

3.2.2 Secondary reserves – automatic frequency restoration reserve (aFRR): This secondary reserve is an insurance product purposed to automatically return the system to nominal frequency within seconds to minutes after a disruption. It has a full activation time of just 5 minutes. It is separated by negative and positive frequency deviations, where the former requires upward regulation while the latter needs downward regulation. Dimensioning is based on historical frequency quality in the entire synchronous area and divided based on the solidarity principle between transmission system operators (TSOs). The payment for this product is related to both the cost of capacity reservation and the cost of energy activation, if it is activated. Energy activation is more expensive per unit, but overall, the cost share of both of them tend to be distributed roughly equally. Additionally, the fast response of this reserve makes it more expensive than manual reserves with less stringent requirements. In hydro-dominated power systems like the Nordic region, there is a seasonal pattern in the aFRR prices since the hydropower flexibility decreases during the spring flood.

3.2.3 Tertiary reserves – manual frequency restoration reserve (mFRR): This is mainly a capacity power market, where activation is done by request from the TSO. The mFRR is stepping in for the aFRR, relieving them to handle new imbalances and disturbances.

3.2.4 Fast frequency reserve (FFR): This product provides only upward regulation and is procured to handle situations of low physical inertia during the event of a disturbance. It is fast in the sense that it is fully activated after 0.7 to 1.3 seconds for a duration of 5 to 30 seconds. Differences in response time are related to the frequency deviation, where a larger initial deviation will trigger a faster response. The dimensioning of FFR products is based on forecasted levels of physical system inertia. Moreover, the demand for this product in 2035 could increase significantly or reduce, depending on the development of the power grid (Svenska Kraftnät, 2024). If more synchronous machine units with high-capacity factors are deployed, it will lead to FFR expansion deferral. Examples of such alternative solutions are nuclear power plants or synchronous condensers.

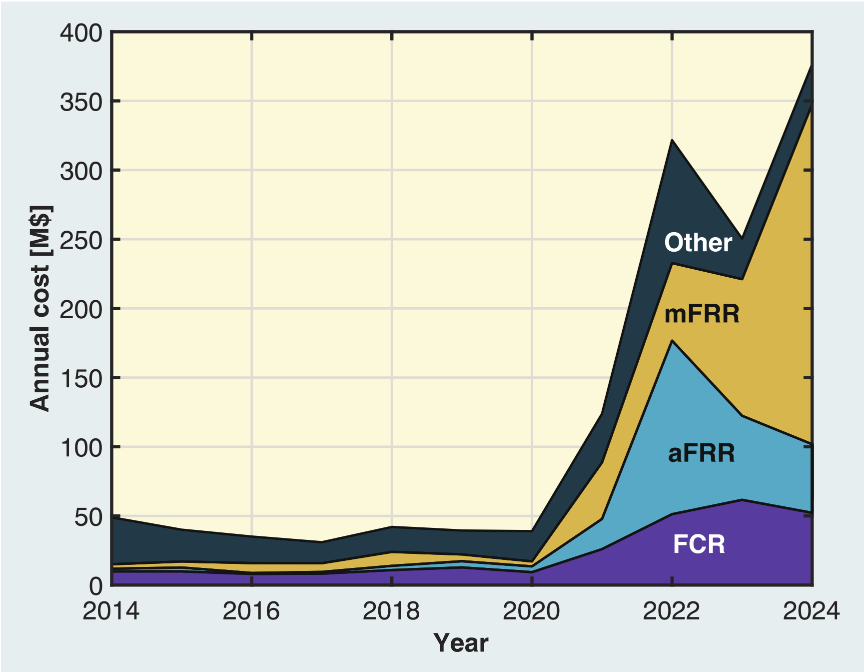

Figure 15. Rise in the annual system costs for operating the Norwegian power system (NVE-RME, 2024) (NVE, 2025), indicating shares of primary reserves (FCR), secondary reserves (aFRR), and tertiary reserves (mFRR). Assumed currency exchange rate is 10.5 NOK/$

The experiences from the German balancing market highlight a remarkable reduction in the volume of procured balancing reserves. Despite solar and wind capacities increasing fivefold between 2008 and 2024, the required balancing reserves decreased by approximately 50%—a phenomenon known as the "German balancing paradox." As illustrated in Figure 16, the allocated upward and downward frequency restoration reserves (FRR) in 2008 were initially comparable in magnitude to the total variable VRE generation. By 2024, however, these reserves represent only slightly more than 10% of the generated VRE volume. Over time, this ratio is expected to stabilize, leading to increased balancing reserve requirements if VRE deployment continues at its current pace in Germany. This contrasts sharply with the trend observed since 2008, during which balancing reserve volumes have generally declined despite substantial expansions in VRE capacity.

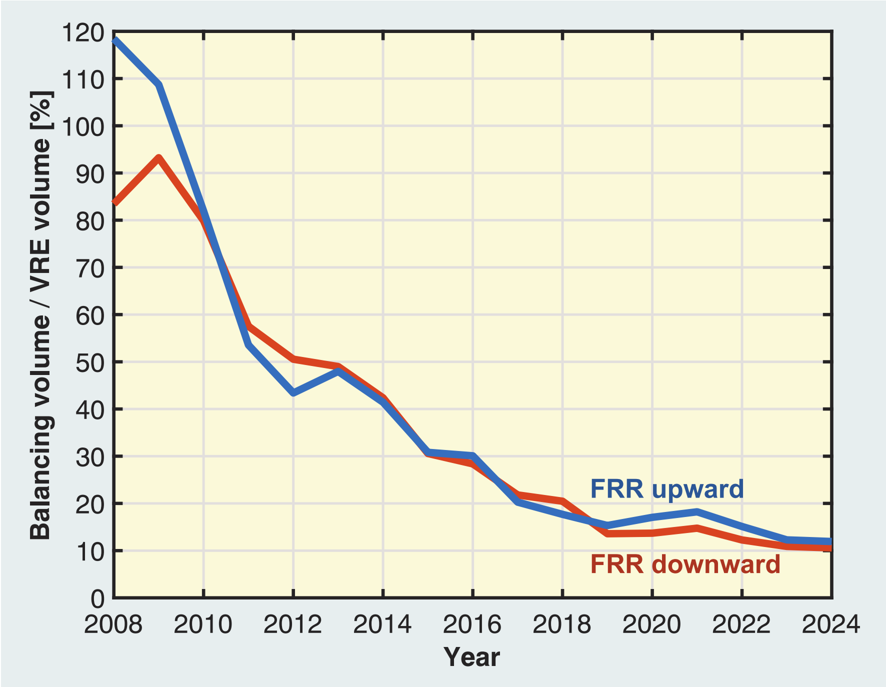

Figure 16. Average ratio of upward and downward frequency restoration reserves (aFRR and mFRR combined) to the total variable renewable energy (VRE) generation from solar and wind in Germany from 2008 to 2024. For more information, see (Koch and Hirth, 2019) (Agora Energiewende, 2025),

4 Non-frequency ancillary services

This section addresses the gaps in the understanding of the future needs and costs for system-bearing ancillary services to support a grid with high penetration of inverter-based resources (IBRs) such as solar and wind power. These are the non-frequency-related ancillary services needed to establish a functioning power grid.

Maintaining frequency stability and restoring it after deviations—roles performed by frequency balancing services described in the previous section—is not sufficient on its own. Voltage levels must also be maintained within defined limits throughout the grid to ensure compliance with the operational requirements of all generating units and consumers. Furthermore, the system must be capable of fault ride-through and fault-clearing to ensure continued stability and reliability. Figure 17 highlights the various ancillary service products used in Europe, including black-start capability and islanded operation modes, which are particularly important for localized power systems and during widespread blackouts.

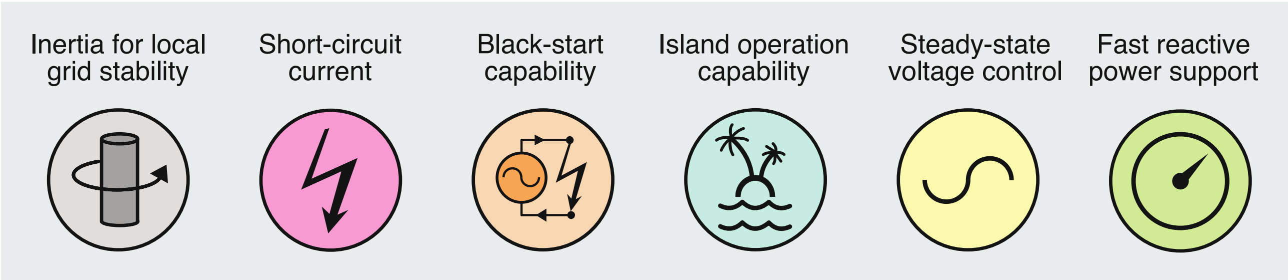

Figure 17. Non-frequency ancillary services used by transmission and distribution system operators (Glowacki Law Firm, 2024).

The Iberian Peninsula blackout on April 30th, 2025, serves as an illustrative case, emphasizing critical lessons about the essential role of ancillary services. Typically, voltage stability deteriorates before frequency stability in blackout scenarios. While frequency is a global phenomenon with slower dynamics due to the inertia provided by rotating masses in synchronous generators, voltage stability is a local issue that changes more rapidly, necessitating localized reactive power support, which is an ancillary service.

During the Iberian blackout, the initial generation losses occurred in Southern Spain, a region characterized by low proportions of synchronous generation resources (García et al., 2025), such as hydro, nuclear, and gas power plants. These are the legacy solutions to provide ancillary services such as voltage support. Although the initial loss of 1.3 gigawatts (GW) of generation appeared to occur prematurely (Red Eléctrica, 2025) voltage instability first manifested as overvoltages in areas lacking sufficient local voltage support due to their minimal synchronous generation capacity.

Spain's power system is increasingly dominated by inverter-based resources (IBRs), such as wind and solar generation. Although these resources can technically deliver critical grid support services—including reactive power for voltage control—regulatory barriers have (Laursen, 2025) until recently, prevented their full utilization in Spain. However, Spain is currently updating its regulations to actively integrate IBRs into voltage control and other ancillary services, aligning its practices with ENTSO-E recommendations and international best practices.

Table 10 outlines the main challenges associated with IBRs compared to synchronous resources. Reactive power support from IBRs, in particular, is inherently unstable, requiring advanced control strategies and active damping—this was among the reasons Spain previously limited their role in voltage support. Nevertheless, future requirements for IBRs should be expanded, mandating grid-forming (GFM) capabilities such as automatic voltage control (AVR) and power system stabilizers (PSS). The latter are especially important for mitigating inter-area oscillations, like those observed between France and Spain just before the Iberian Peninsula blackout.

Table 10. Provision of essential ancillary services from synchronous and inverter-based resources.

Ancillary service	Local grid inertia	Grid strength	Reactive power support
Synchronous resources	Physical noncontrolled inertia with instantaneous response, storing 2 to 6 seconds of rated power (Nøland *et al.*, 2024a).	500 to 600 percent higher fault current than the nominal rating (Kroposki and Hoke, 2024).	Static and dynamic reactive power support from the excitation system through an automatic voltage regulator (AVR) and a power system stabiliser (PSS). However, smaller units only provide static support.
Inverter-based resources	Synthetic controlled inertia with latency and limited power output and energy storage reserves.	10 to 30 percent higher fault current than the nominal rating (Kroposki and Hoke, 2024)	Fast reactive power support through programmable software algorithms but is inherently unstable and needs advanced controls and active damping techniques. However, IBRs tend to be smaller and more dispersed, which reduces their grid code obligations.

As outlined above, the primary challenge with ancillary services is establishing sufficient constraints for their allocation. This is important as IBRs are expected to dominate much more in the future, considering higher penetrations of renewables. Moreover, modern grid-forming IBRs, which are gradually replacing grid-following IBRs, can contribute to additional system-supporting services such as AVR and PSS. Nevertheless, they still will lack other critical capabilities needed to function as a standalone solution in macro-scale power systems, which makes them partially grid-forming. In particular, their short-circuit current contributions are limited, typically only 10 to 30 percent above nominal levels (Kroposki and Hoke, 2024). This results in a weaker grid that is more challenging to operate and maintain, especially when it comes to fault ride-through and fault clearing.

Grid-forming IBRs are at risk of being redundant if large-scale synchronous condensers (SynCons) otherwise would be needed to ensure all system-bearing services for a functioning grid. SynCons are considered a cost-effective solution relative to GFMs if multiple ancillary services are needed at the same time. Nevertheless, the future need for SynCons will depend on the share of synchronous resources in a climate neutral power system, such as nuclear, geothermal, hydropower, and combined-cycle gas plants with CCS, as well as how often these resources are dispatched in the day-ahead market or redispatched after market-clearing. If these units also participate in a future ancillary services market, they could gain additional revenue streams, improving their economic competitiveness and potentially reducing the need for separate SynCon deployment. Additionally, these synchronous plants can be equipped to operate in SynCon mode during periods when they are not generating electricity.

The future electricity mix can be divided into synchronous resources and IBRs, where the former is fully grid-forming while the latter is grid-following or partially grid-forming (see Figure 18). Although inverter-based resources can indeed be configured as grid-forming, in this context they are described as partially grid-forming to differentiate them from synchronous resources, which possess the capability to provide the grid strength necessary to clear out and ride through faults in large-scale power systems. Nuclear and geothermal power plants can provide synchronous resources with the highest availability and can provide these ancillary services around the clock throughout the year without allocating them to other service providers. Although nuclear and geothermal power plants individually can achieve availability factors of 90 to 95 percent, their practical capacity factors tend to be lower due to their dispatch within electricity markets, with geothermal typically experiencing significantly lower capacity factors compared to nuclear. However, when it comes to ancillary service provision, the key metric is fleet availability—not capacity factor—as these plants can be reallocated through the TSO's redispatch mechanisms following market clearing. Nonetheless, although fleets of firm generation can inherently provide ancillary services around the clock and throughout the year, grid operators avoid relying exclusively on a single type of generation asset to diversify the portfolio of solutions. At the same time, the anticipated hydropower capacity upgrades will increase their power output and inertia. However, the peak power output will be delivered over shorter time periods, thus, reducing their capacity factors in the future power grid. Similarly, the bio and hydrogen power plant's high marginal prices lead to fewer operational hours and lower capacity factors.

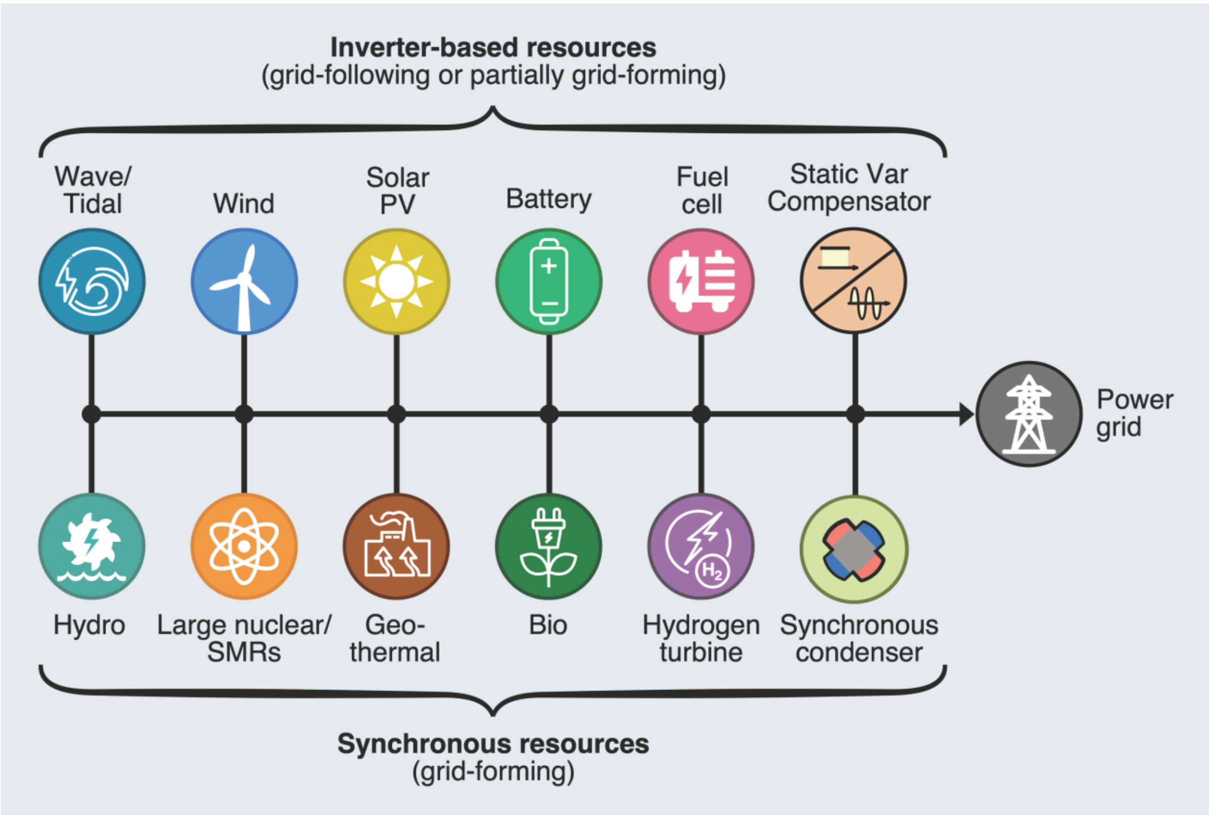

Figure 18 Overview of IBRs and non-IBRs in a fossil-free power grid. Note that, to be consistent with fossil-free generation, fuel cells and hydrogen turbines can only be fueled by non-fossil hydrogen.

With the lack of synchronous resources throughout the year, alternatives such as SynCons are needed to ensure that all the ancillary services are available locally. Figure 19 highlights the levelized cost of operation when the voltampere rating of a SynCon is paired with the kilowatt rating of an IBR. A capital expenditure of \$400 per kVA implies SynCon newbuilds, while \$200/kVA and \$100/kVa assume the costs of making existing power units able to run as SynCons when they are not ordered to produce electricity in the power market (Nøland *et al.*, 2024a).

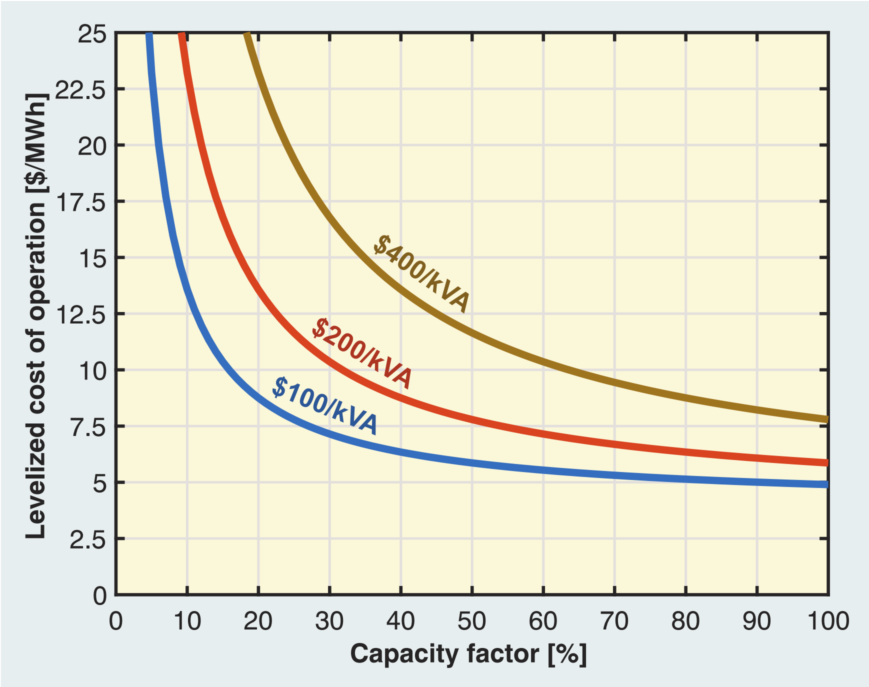

Figure 19 Estimated levelized cost of operation (LCOO) of SynCons paired with inverter-based resources as a function of capacity factor. Three different SynCon cost levels are plotted, depending on more expensive new builds or if SynCon components are installed in existing machines. Calculations assume a 5% interest rate, 30-year capital recovery time, 3% power losses relative to kVA-rating, and 2% annual operation and maintenance costs relative to initial capital expenditure.

4.1 Reactive power support and voltage regulation

Supply and demand for reactive power need to be balanced to ensure a power system's voltage stability. Today, large synchronous resources are the main providers of reactive power. This is because stricter grid code requirements typically apply to larger generation units, whereas IBRs are often smaller and more dispersed. Consequently, ensuring adequate static and dynamic voltage support, critical for preventing events like the Iberian Peninsula blackout, becomes challenging. Due to limited opportunities for reactive power provision under current grid codes, particularly for distributed generation (DG), proposals have emerged to establish dedicated reactive power markets (Bhattacharya and Zhong, 2001) (Potter et al., 2023). Voltage stability is more of a local phenomenon than frequency stability, although local voltage stability issues depending on the regional grid codes can initiate widespread blackouts. Grid codes set the requirements for local reactive power support, while a reactive power market has not yet emerged. For smaller units of IBRs, e.g., less than 1 MW, there are no reactive power requirement (ENTSO-E, 2016). For larger units below 10 MW, there are only static reactive power support requirements. The same applies to synchronous resources, however, IBR units tend to be smaller in size and more dispersed.

Fluctuation of VRE sources causes voltage fluctuations and flickers due to variations in reactive power demand. For wind power, these variations depend on wind speed variations and the type of generation system. For example, in wind power, doubly-fed induction generators have been common in the past, which, by their very nature, consume reactive power (i.e., they require a reactive power source for excitation). So, they do not have the advantage of supporting the grid with reactive power like the grid-connected synchronous machine. However, converter-fed wind generation systems driven by permanent magnet generators mitigate the need to consume reactive power, but they need additional dimensioning to be able to supply reactive power to the grid at nominal conditions, depending on the grid code. Control strategies have been proposed for wind power plants via voltage source converters to adhere to the grid code's reactive power support requirements (Shakir D. Ahmed *et al.*, 2020). However, the ability of dispersed sources to produce or absorb reactive power depends on the strength of the grid and the length of the transmission lines. The short-circuit impedance at the connection point between the grid and the VRE resource also contributes to the voltage fluctuations. Existing reactive power compensation schemes are found ineffective for distributed and dispersed VRE resources, making the case for a reactive power market (Potter et al., 2023).

4.2 Grid strength level

A power system's grid equivalent seen at every node describes the grid strength quantified as the short circuit level (SCL). Strong grids have an SCL of 3 or higher, implying that transiently, they can provide three times higher fault current than the nominal current level. The dynamic characteristics of synchronous machines imply that their SCL is much stronger transiently than steady state. However, strong SCL is only needed transiently to ensure sufficient fault current to detect and clear out the fault. For a larger interconnected grid, it is possible to increase available SCL by strengthening the transmission between regions with different grid strengths. However, to address future challenges, it is essential to understand the impacts of weaker power grids and their operational challenges to ensure secure and resilient operations. Different approaches to enhance the grid strength should be considered, including the role of synchronous resources, deployment of SynCons, and increased grid capacity between regions with significant differences in grid strength.

4.3 Local grid inertia

Noncontrolled physical grid inertia is needed to ensure stability initially during a disturbance before the frequency balancing services kicks in. These spinning reserves can be accessed externally through interconnected regions; however, maintaining sufficient local inertia is recommended to ensure local grid stability, enabling the grid to reliably operate in island mode when needed. Inertia is characterized as the system-level inertia constant (H), describing the amount of noncontrolled physical inertia available at every time instant. Hydro generators and turbogenerators (gas and nuclear) have an H-value in the range between 2 to 6 seconds, defined as the ratio between rotational energy and the nominal power rating. ENTSO-E recommends maintaining a long-term average inertia constant (H-value) of above 2 seconds (ENTSO-E, 2025) for each synchronous area of an interconnected power system. These are spinning reserves that increase grid reliability in the case of unexpected events that are difficult to predict. A lack of physical inertia impacts the grid's initial stability during a power imbalance event. Understanding the needs informs the capacity expansion of additional power system components, such as

SynCons, to ensure sufficient grid inertia at every time instant. Additionally, grid strengthening helps access grid inertia from high-inertia regions. Allocating fast frequency reserves (FRRs) can also be a good supplement in case there is a lack of grid inertia in very short time intervals, as the cost of operating SynCons gets very high when the capacity factor is low. Moreover, the question is, who will pay for the inertia if the existing inertia provided by synchronous resources is not sufficient? With longer periods of low inertia, an inertia market will have to emerge, which will have its costs. Alternatively, the TSO will have to set arbitrary constraints on the grid to encourage more synchronous resources to run. One example is to reduce the power capacity of interconnectors, which would have its own cost in terms of lower use and could be higher than the cost of an ancillary service market.

4.4 Oscillation damping

Prior to the Iberian Peninsula blackout on April 30th, a utility-scale solar farm in Extremadura (Corredor et al., 2025) (province of Badajoz, Spain) was identified as the source of forced frequency oscillations, initially at 0.6 Hz, due to faulty internal control systems within the solar facility. These forced oscillations were not effectively damped by the power system because of limited dynamic voltage support and inadequate oscillation-damping resources, such as PSS typically provided by legacy synchronous generators or advanced IBR controls, where the latter faces regulatory constraints.

In addition to these forced oscillations, inter-area frequency oscillations between France and Spain also emerged before the blackout. This was primarily due to a weak, heavily loaded interconnection line with France, however, a significant disparity in inertia constants between the two interconnected regions also contributed. The low inertia in Spain resulted from a high penetration of inverter-based renewable generation (primarily solar and wind) during hellbrise at midday. The abundant solar generation further increased power exports, placing additional stress on the interconnection to France. Reports indicate that the Iberian grid and the broader European network oscillated out-of-phase at around 0.2 Hz. The Spanish government's report (Gobierno de España, 2025) explicitly highlighted that improved interconnections would have mitigated both the likelihood and severity of these oscillations. Nevertheless, the sustained inter-area oscillations were primarily due to the insufficient availability of PSS-equipped synchronous generation or advanced IBR damping controls on renewable units.

4.5 Black-start capability

The recovery after the Iberian Peninsula blackout was slowed by limited black-start units and the careful choreography required to rebuild the grid from zero. In the immediate aftermath of the blackout, several hydroelectric plants were used to initiate black-start procedures. Notably, the Aldeadávila hydroelectric plant in Salamanca (on the Duero River) provided the first injection of power into the dead grid, having the rare ability to start without any external supply. Moreover, according to Iberdrola, a fleet of its pumped-storage hydropower (PSH) facilities – including Aldeadávila II, Puente Bibey, Villarino, and La Muela I & II – were instrumental in the early recovery. Once initial voltage and frequency were established by the hydro station, Spain could begin restarting gas-fired power plants to increase generation and rebuild the system step by step.

5 Copper plate grid limitation

This section focuses on transmission-related simplifications in energy system planning and how this simplification will impact the results in capacity expansion modeling. In these models, nodes typically represent a larger region where there are no transmission bottlenecks within each node, referred to as the "copper plate grid model" (Raheel A. Shaikh *et al.*, 2023), as illustrated in Figure 20. This assumption reduces the number of nodes in an energy system optimization model, thus making it easier to find an optimal solution at lower computational costs. Nevertheless, neglecting the total grid cost means that in a model node (continent, country, or region), an ideal exchange of power flows is possible without any transmission constraint, which is the reason for the so-called "copper plate" term. This simplification obviously leads to inaccurate system-level costs and can distort the cost-optimal power generation portfolio(Hess *et al.*, 2018). In the most extreme case, having no grid constraints or bottlenecks means that when and where electricity is produced is independent of its value, which could vastly overestimate the value of VRE resources in energy system models. If transmission losses are not adequately accounted for, large-scale capacity expansion models will tend to cluster energy resources in specific regions or countries. Moreover, overlooking costs related to congestion could underestimate costs by 23% (Frysztacki *et al.*, 2021). To address some of these concerns, a node-internal transmission and distribution grid model has been proposed (Hess *et al.*, 2018).

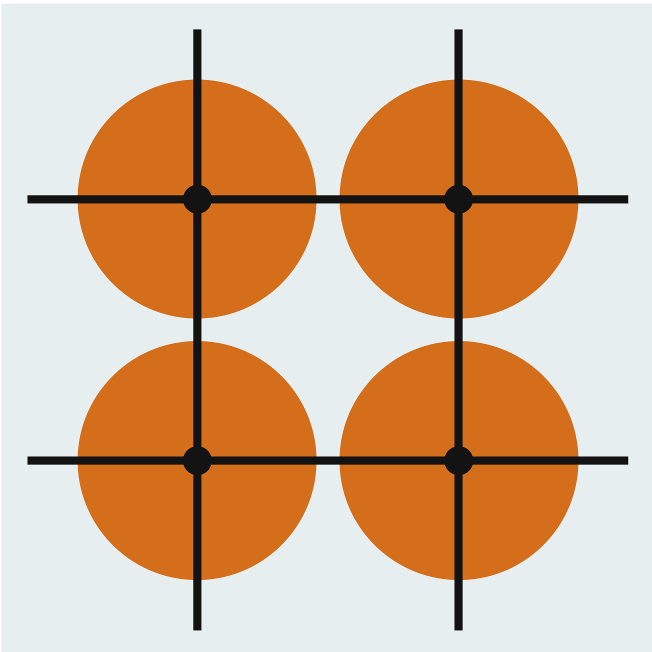

Figure 20 Depicts a conceptual low-resolution transmission network, in which the power distribution within each node is represented by an idealized "copper plate." While this simplifies the model and reduces complexity, it also diminishes accuracy by neglecting local real-world constraints.

5.1 Grid connection and expansion

The grid connection cost of different energy resources depends on their location and the connection point to the transmission grid. According to the NREL, the grid connection costs vary from $100 per kilowatt (kW) for onshore resources and up to $4000/kW for floating offshore wind resources (NREL, 2024b). Figure 21 illustrates the levelized cost of transmission (LCOT) for different grid connection cost levels and use. The LCOT is insignificant for the cheapest grid connections, assuming a high-capacity factor. However, as the cost of grid connection increases, the grid connection costs can become a significant part of the total system costs of an energy project. Grid expansion costs associated with existing grid infrastructure are additional, but these costs can be shared among multiple generation assets. Nevertheless, grid capacity must be sufficient to accommodate expected peak generation levels, as these peaks ultimately will determine the transmission grid's dimensioning.

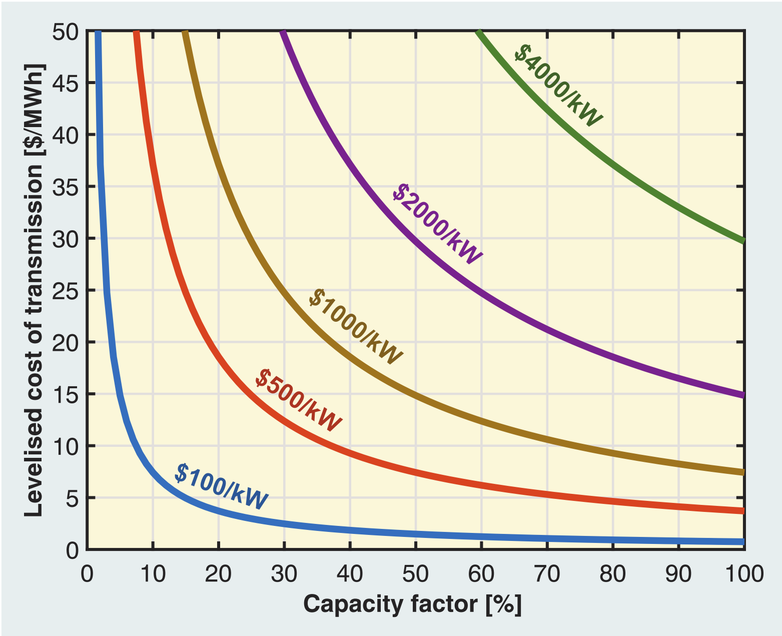

Figure 21. Levelized cost of transmission (LCOT) for different grid connection cost levels and capacity factors, assuming a 30-year capital recovery time and a 5% interest rate, while neglecting operation and maintenance (O&M) costs.

5.2 Transmission grid (HVAC)

Significant grid bottlenecks can exist between regions or zones of a larger interconnected power market. A decarbonized Europe in 2050 with a two-thirds energy supply from VRE requires roughly a fivefold increase in the transmission grid capacity (Golombek *et al.*, 2022). It is important to note that part of the increase in transmission capacity is driven by rising electricity consumption. Transmission expansion is the enabler of the energy transition. Nevertheless, expanding the grid at this scale presents a major challenge, as large and often contested transmission projects can take a decade or more to plan, permit, and construct.

5.3 Regional and distribution grid

Within each region or power market zone, there could be significant bottlenecks, and a portion of the new generation portfolio could be dispersed and distributed, with a certain electrical distance to the transmission grid, thus potentially impacting the use of such new distributed generation, not accounted for in energy system planning models.

5.4 Interconnectors (HVDC)

Capacity expansion models tend to favor a significant expansion of interconnectors. However, such expansions could end up being challenging to deploy in time, also due to political barriers. Moreover, today, we already see that HVDC interconnector capacities are curtailed periodically due to power system operational constraints (European Commission, 2018), e.g., not enough ability to import due to lack of synchronous resources running the grid. HVDC interconnectors also have reliability issues, implying the need for procured balancing power market reserves to handle a potential outage.

6 Demand-side flexibility

This section explores the overlooked costs of developing, implementing and maintaining system flexibility, including storage, demand response, and interconnections. It highlights the gap between system-wide optimisation and consumer priorities, the cost of unserved energy, and the risks of overestimating flexibility in energy models, which can lead to price volatility and inefficiencies.

6.1 Investment in flexibility infrastructure

Maintaining system flexibility requires significant investments in energy storage, demand response programs, flexible backup generation, and interconnections with neighboring grids. These costs are often overlooked, leading to underestimation of the resources needed to ensure reliability in renewable-rich energy systems.

The costs associated with these measures include capital expenses, operational expenditures, and long-term system integration challenges. For example, energy storage systems such as batteries require high upfront costs, limited lifespans, and degradation over time, which require periodic replacements and maintenance. Fire safety and recycling was also proposed as key challenges (Huang and Li, 2022). To integrate energy storage systems, some barriers and associated costs were highlighted by scholars (Elalfy *et al.*, 2024), including battery deterioration, inefficient energy operation, sizing and allocation, and financial feasibility. Moreover, deploying demand response programs demands substantial investment in smart grid technologies, consumer engagement, and regulatory frameworks to enable efficient load shifting (Malbašić and Pandžić, 2022).

Interconnections with neighboring grids offer system flexibility by facilitating power exchanges, yet these require large-scale infrastructure upgrades and harmonization of market and regulatory policies across regions. Flexible backup generation, such as gas turbines, incurs both direct costs for installation and indirect costs due to underuse in high-renewable scenarios (Schill and Zerrahn, 2018). These factors are often underrepresented in cost-benefit analyses, leading to an over-reliance on optimistic assumptions about renewable energy integration.

6.2 Misalignment of generation- and consumer-centric perspectives

System-level optimization models often assume an idealized level of demand-side flexibility, like treating all EVs and heat pumps as equally responsive to price signals—focusing on societal goals (e.g., minimizing cost or emissions) while ignoring real-world consumer differences. For instance, Stampatori & Rossetto (Stampatori and Rossetto, 2024) review behavioral barriers and find that lack of awareness, skills, and inertia significantly reduce participation in flexibility markets—even when incentives are offered. Similarly, Li *et al.* (Li *et al.*, 2020) studying UK households show that responses vary by socio-demographic factors and appliance ownership, with many consumers unwilling or unable to shift activities like cooking or heating. These findings highlight that assuming uniform flexibility in models can lead planners to underestimate peak loads and overestimate system responsiveness, risking inadequate infrastructure design.

Energy-intensive industry consumers with significant upfront capital investments may lack adequate incentives for flexible consumption, contrasting with the behavioral assumptions made in these studies. Such consumers face significant risks if their operational schedules are disrupted, making them less likely to participate in demand response or other flexibility programs.

Alternatively, consumers may focus on minimizing their own operational costs through flexibility, which can create discrepancies in expected flexibility contributions. For example, residential or commercial consumers leveraging rooftop solar and battery systems may focus on reducing their electricity bills rather than contributing to grid-level balancing. This leads to discrepancies in expected flexibility contributions (Schill *et al.*, 2017).

Consumers with lower capital costs and higher variable operating costs have higher incentives for flexibility, which need to be identified to evaluate the role of flexibility in energy system models more accurately. As an example, more volatile electricity prices and more presence of negative or zero electricity prices may be the end result if the role of flexibility ends up being overestimated in the energy planning phase.

6.3 Cost of unserved energy and flexibility incentives

A key overlooked cost is the economic impact of underperforming flexibility solutions. For instance, if storage systems fail to deliver the anticipated response times, it may necessitate reliance on more expensive backup power sources, increasing system costs (Zakeri and Syri, 2015). The cost of not having electricity can exceed the price of electricity itself. It tends to become the main driver of energy solutions for mission-critical applications, or long duration events where the value of lost load can increase exponentially. For instance, data centers often have their own backup diesel-fueled power generation locally to ensure uninterrupted operation and avoid the costs of unserved energy. For example, a 100-MW hyperscale data center could have a cost of downtime of roughly $10,000 per minute (Aggreko, 2023), implying that the cost of unserved energy could be as high as $6000 per megawatt-hour (MWh). In fact, existing data centers are sometimes willing to double their initial capital investment to reduce their downtime by just one day per year (KIO Data Centers, 2024). Flexibility incentives must account for the varying willingness of consumers to adjust their usage based on their operational characteristics, ensuring that market designs reflect real-world constraints. Nevertheless, since data centers already have their own secondary power supply, they do have some flexibility assets, though these are many times based on fossil fuels. Moreover, their incentive to operate in a flexible manner to reduce electricity costs is limited (Nøland *et al.*, 2024b).

6.4 Risks of overestimating flexibility in energy models

The third perspective is the modeling. Anderson *et al.* pointed out that the commonly-used resource planning model, such as linear programming relaxed methods cannot accurately capture the behavior of thermal units and pumped storage units, and tend to overestimate their operational flexibility (Anderson *et al.*, 2025). Consequently, this overestimated operational flexibility will likely lead to sub-optimal investment solutions. Overestimating demand-side flexibility in energy system planning can lead to increased price volatility and frequent occurrences of negative or zero electricity prices. Fraunhofer's analysis (Kühnbach *et al.*, 2021) warns that unmanaged demand-side flexibility, especially from EVs, can trigger so-called "avalanche effects," where synchronized charging during low-price periods creates new demand peaks that overwhelm the system and increase price volatility. Their simulations show that without real-time, decentralized control, large-scale EV adoption may exacerbate grid stress rather than alleviate it. Similarly, Kühnlenz *et al.* (Kühnlenz *et al.*, 2018) use an agent-based model to demonstrate that naively implemented real-time pricing can lead to collective, simultaneous demand shifts that destabilize the system and raise electricity costs. Both studies caution against overestimating flexibility without incorporating behavioral diversity, control technologies, and system-level coordination.

Another underexplored dimension is the socio-economic trade-off between cost-optimal energy pathways and their political or social acceptability. Overestimating flexibility may lead to models prescribing solutions that, while theoretically efficient, are practically unfeasible or unpopular due to high upfront costs or disruptions to communities (Trutnevyte, 2014).

6.5 Electricity price volatility

Electricity price volatility—the extent to which electricity prices fluctuate over time—is a critical but often underappreciated dimension of power system planning. While models tend to emphasize cost optimization and average price levels, volatility itself can create major financial risks, reduce predictability, and undermine industrial competitiveness. The analysis performed by QC for Sweden (Quantified Carbon, 2025) shows that future power systems are likely to experience both higher price levels and greater volatility, especially in scenarios with high reliance on imports and weather-dependent renewables without sufficient dispatchable capacity. This underscores the need for more robust consideration of volatility when evaluating system flexibility and its associated costs.

By analyzing quarterly price variations across 33 historical weather years, our study reveals that scenarios with high shares of dispatchable resources, like new nuclear and gas turbines, tend to moderate both average prices and volatility. In contrast, systems lacking firm capacity—such as the "No Nucl." and "No Nucl. No Fossil" scenarios—exhibit extreme volatility and higher price levels, potentially making them socially and economically unacceptable. This finding highlights a crucial point: electricity market participants and planners must prepare for higher volatility as a systemic feature, not just an anomaly, and treat it as a key input in assessing the viability of future flexibility investments and market designs.

7 Extreme weather events and resilience

This section addresses the growing threat that climate change poses to power system resilience, particularly through the increasing frequency and severity of extreme weather events. As we decarbonize by expanding weather-dependent variable renewable energy sources, the power system becomes more vulnerable not only to renewable output variability but also to climate-driven disruptions affecting firm generation sources. These include declining hydro availability due to droughts, thermal power plant deratings from cooling water shortages, and biomass supply constraints from shifting precipitation patterns and heat stress. Managing this dual challenge—operational variability and climate-induced physical risks—requires integrating climate risk assessments into infrastructure design, operational strategies, and long-term energy planning to safeguard grid stability and system adequacy.

7.1 Historical analysis of extreme weather impacts on power systems

Extreme weather events have caused significant disruptions to power grids worldwide, leading to widespread power outages, economic losses, and, in many cases, loss of life.

One of the most devastating events in recent years was Winter Storm Uri (Clack *et al.*, 2021) in February 2021, which crippled the Texas power grid. Prolonged freezing conditions, combined with unprepared infrastructure, led to failures in gas pipelines, wind turbines, and thermal power plants. More than 4.5 million people were left without electricity for several days, and approximately 246 deaths were reported due to hypothermia, carbon monoxide poisoning, and accidents. The economic toll reached billions of dollars. This event exposed the vulnerabilities of power grids to rare but severe weather phenomena, emphasizing the need for grid "winterization". The blackout was primarily caused by a combination of surging electricity demand and a sharp decline in available supply. As temperatures plummeted, Texans increased heating usage, pushing demand to unprecedented levels. Simultaneously, many power plants, particularly those fueled by natural gas, failed due to equipment freezing and fuel supply disruptions. This supply-demand imbalance forced grid operators to implement rolling blackouts to prevent a total system collapse.

Another critical incident was the United Kingdom Blackout of 2019 (Department for Business, Energy & Strategy, 2020; MacIver *et al.*, 2021), caused by a lightning strike. This event disrupted power supplies to 1.15 million people across the UK. Although power was restored within 45 minutes, the blackout caused significant disruptions, particularly to transportation systems, such as trains, leaving passengers stranded. Economic losses were estimated at £10.5 million. This case highlighted the interconnectedness of power and other critical systems and the importance of robust contingency planning. This meant that the resilience of the power system — including its ability to withstand and rapidly recover from faults — was critical not only for electricity supply but also for maintaining broader societal functions. Furthermore, between late 2024 and early 2025, Ireland and the UK experienced a series of severe windstorms that caused significant power disruptions. Notably, Storm Darragh in December 2024 brought wind gusts up to 93 mph, leading to power outages for nearly 400,000 customers in Ireland and over 1.8 million in the UK ("Storm Darragh," 2025). Similarly, Storm Éowyn in January 2025 recorded record-breaking winds of 183 km/h in Ireland, resulting in more than 700,000 power outages.

The California Wildfires of 2020 (Newsom *et al.*, 2021) also demonstrated the interplay between extreme weather and power grid vulnerabilities. Wildfires driven by high winds and dry conditions led to pre-emptive power shutoffs, affecting millions of residents to prevent further ignitions.

These outages caused significant disruptions to businesses and communities, while the wildfires themselves resulted in billions of dollars in damages and the loss of dozens of lives. This example underscores the challenges of balancing grid reliability and safety during extreme weather.

In 2012, Hurricane Sandy (NIH, 2013) brought devastation to the northeastern United States. Floodwaters overwhelmed substations and underground infrastructure, leaving over 8 million people without power. This event caused approximately $65 billion in damages and highlighted the vulnerability of coastal regions to storm surges and the cascading effects of infrastructure failures. It emphasized the importance of hardening critical facilities, such as substations, against future extreme weather.

The European Heatwave of 2003 (Domínguez Cerdeña *et al.*, 2006) presented a different challenge. Record-breaking temperatures stressed power grids as electricity demand surged for cooling. Thermal power plants faced operational challenges due to insufficient water for cooling, resulting in power outages across parts of Europe. This event, which caused tens of thousands of heat-related deaths, highlighted the importance of grid adaptability during prolonged heat events and the necessity of integrating renewable energy sources to reduce dependency on thermally sensitive generation.

As it is show on Figure 22 and Figure 23 the continental European power system despite substantial investment in solar and wind capacity accompanied by expected smoothing of power generation from these variable generators due to the spatial distribution of variable renewable resources is still subject to periods of very low generation, hereafter referred to as energy droughts (ger. Dunkelflaute) (Domínguez Cerdeña *et al.*, 2006). These events highlight the inherent challenges in managing power systems dominated by VREs.

While the aforementioned events underscore the vulnerabilities of power systems to acute and often localized extreme weather incidents, they do not encompass the challenges posed by prolonged, widespread deficits in renewable energy generation. These extended periods, known as "Dunkelflaute" (Domínguez Cerdeña *et al.*, 2006) or energy droughts, are characterized by simultaneous low wind and solar output across vast regions, presenting a distinct set of challenges for energy systems heavily reliant on variable renewable energy sources. Unlike sudden disruptions, Dunkelflaute events or low VRES supply events can persist for days or even weeks (Kittel and Schill, 2024). In their 2024 study, Kittel & Schill (Kittel and Schill, 2024) identify the most extreme Dunkelflaute in Europe during the winter of 1996/97, which, across a perfectly interconnected European grid, lasted 55 days, with combined wind and solar output averaging only 47% of their long-term mean (Figure 22 and Figure 23), necessitating robust strategies for energy storage, grid interconnectivity, and demand-side management to maintain system reliability. The following section delves into the implications of these energy droughts and explores potential solutions to mitigate their impact on power system resilience.

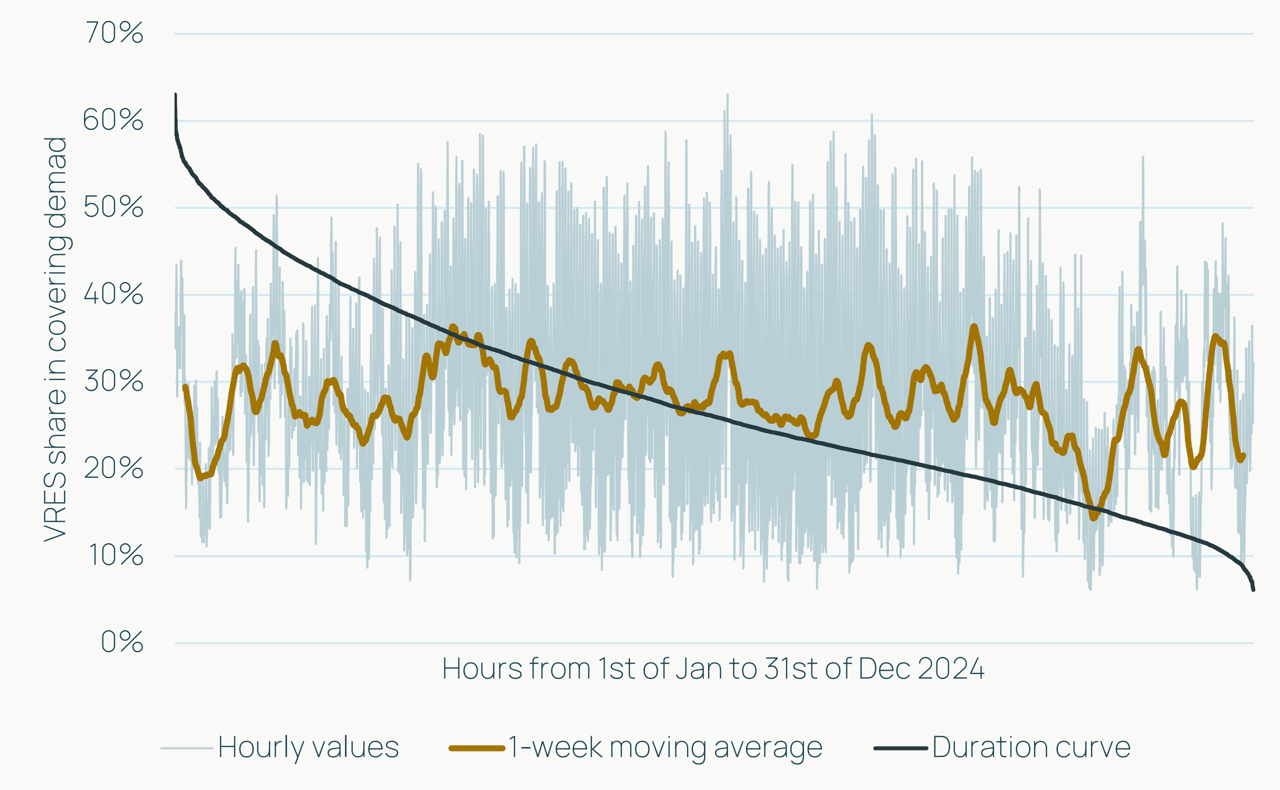

Figure 22. Solar PV and wind (onshore + offshore) share in covering the electricity demand on the European Union level in 2024, source: EnergyCharts.de

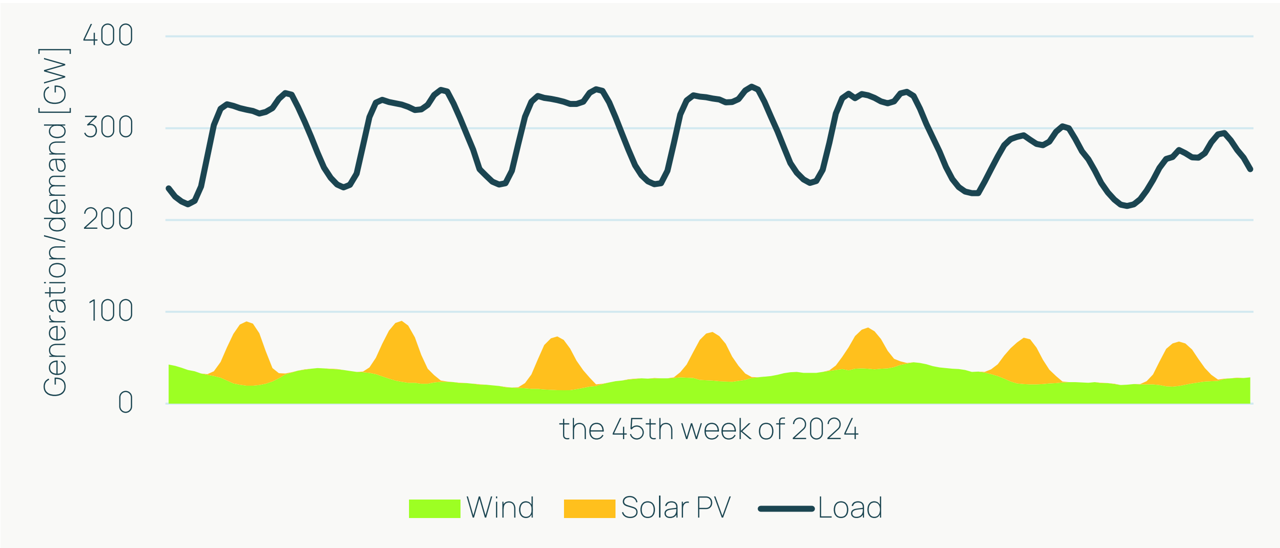

Figure 23. Extreme week with very low solar PV and wind (onshore + offshore) generation on the EU level, source: EnergyCharts.de. Although the load is about 5 % above the 2024 average, wind generation is down by 42 % and solar PV by 37 % compared to their annual averages.

To mitigate the risk of energy droughts, power systems must be designed with significant overcapacity and more transmission from areas that may be less impacted by events and have excess energy available. This entails installing a capacity of renewable generators that far exceeds average demand to ensure adequate production during low-generation periods. However, power plants in the same area may also be affected, and neighboring facilities might be experiencing similar conditions. In addition, this approach can lead to inefficiencies and increased system costs, as a significant portion of the installed capacity may remain underused during periods of high generation. Furthermore, while the geographical dispersion of VREs across a continental power system can reduce the frequency of extreme low-generation events, it does not eliminate them. Coordinated and higher levels of transmission interconnections, such as those enabled by the European grid, can partially alleviate the impacts but rely on the availability of surplus generation in connected regions. During continent-wide energy droughts—extended periods of low wind and solar generation—interconnections alone may be insufficient to prevent high residual demand, as illustrated in Figure 23. Residual demand refers to the portion of electricity demand that remains unmet after accounting for generation from variable renewable energy sources like wind and solar. In such scenarios, even extensive grid interconnections may struggle to compensate for the shortfall, as neighboring regions are likely experiencing similar deficits in renewable generation. Planning for robust and resilient power systems in high VRES share contexts must account for these dynamics. The reliance on overcapacity, coupled with effective balancing and storage solutions, is a common feature of 100% renewable pathways, and is the cornerstone of ensuring system reliability during energy droughts in this modeling literature (Delucchi and Jacobson, 2011) (Child et al., 2019). In addition, consideration for additional resources in the form of demand response, alternative fuels such as hydrogen, or other energy streams should be considered to support consumers during long-duration, widespread environmental events.

7.2 Climate change and increasing frequency of extreme events

This subsection presents an analysis of how climate change is projected to increase the frequency and intensity of extreme weather events and the implications for power system stability, including anticipated impacts on grid reliability and energy security.

- Energy droughts (wind/solar) and their spatio/temporal distribution in the future,

Traditional power system planning heavily relies on historical data to model solar and wind potential and variability. While this approach has been effective in the past, it may fall short in addressing the future dynamics of renewable energy resources. Climate change introduces significant uncertainties, including shifts in resource potential and changing patterns of generation, which must be accounted for to ensure the reliability and stability of future power systems. The variability of renewable energy sources, particularly wind and solar, is influenced by weather patterns and environmental conditions (e.g., smoke from wildfires) that are expected to evolve due to climate change. Studies, such as that by Kapica *et al.* (Kapica *et al.*, 2024), have demonstrated that resource availability could change significantly in different regions of Europe, with potential increases in energy droughts—periods of persistently low wind or solar generation—especially under high-emission scenarios like RCP (Representative Concentration Pathway). This challenges the assumption that historical patterns will remain consistent and highlights the importance of integrating forward-looking climate projections into system planning.

In many regions, these changes could manifest as decreased wind speeds or altered solar radiation patterns, affecting both the magnitude and timing of renewable energy generation. For example, wind resources in Southern Europe are projected to decline, while in Northern Europe, increased variability could pose challenges for balancing supply and demand. Similarly, solar generation may experience higher variability due to increased cloud cover in certain seasons or regions.

Addressing these challenges requires a paradigm shift in power system modeling and planning. Instead of relying solely on historical data, planners must incorporate climate-adjusted datasets and model scenarios that reflect potential future conditions. Climate models, such as those used in the EURO-CORDEX project, provide granular projections of wind and solar variability, enabling the development of more robust strategies for integrating VREs.

- Heat and cold waves -(Lubega and Stillwell, 2018)-> spikes in electricity demand heavily impacting power systems with insufficient peak capacity. High temperatures impacting efficiency of power plants, icing phenomena decreasing wind turbines output, snow cover reducing/stopping PV generation. These issues are often overlooked in power system modeling studies.

During the 2024 European heatwave (Jahn and Laurie Burnham, 2024) high temperatures led to a significant reduction in the efficiency of PV systems, decreasing overall power output. Other events severely impacting PV are high wind events, convective storms (hail, tornados and straight-line winds), snowstorms and blizzards, dust storms, heat waves, floods and wildfires.

For example (Jahn and Laurie Burnham, 2024), a dust storm in Spain reduced PV generation by 50% for two weeks in 2022, Figure 23. In Portugal (2017) similar event resulted in power loss as high as 8%.

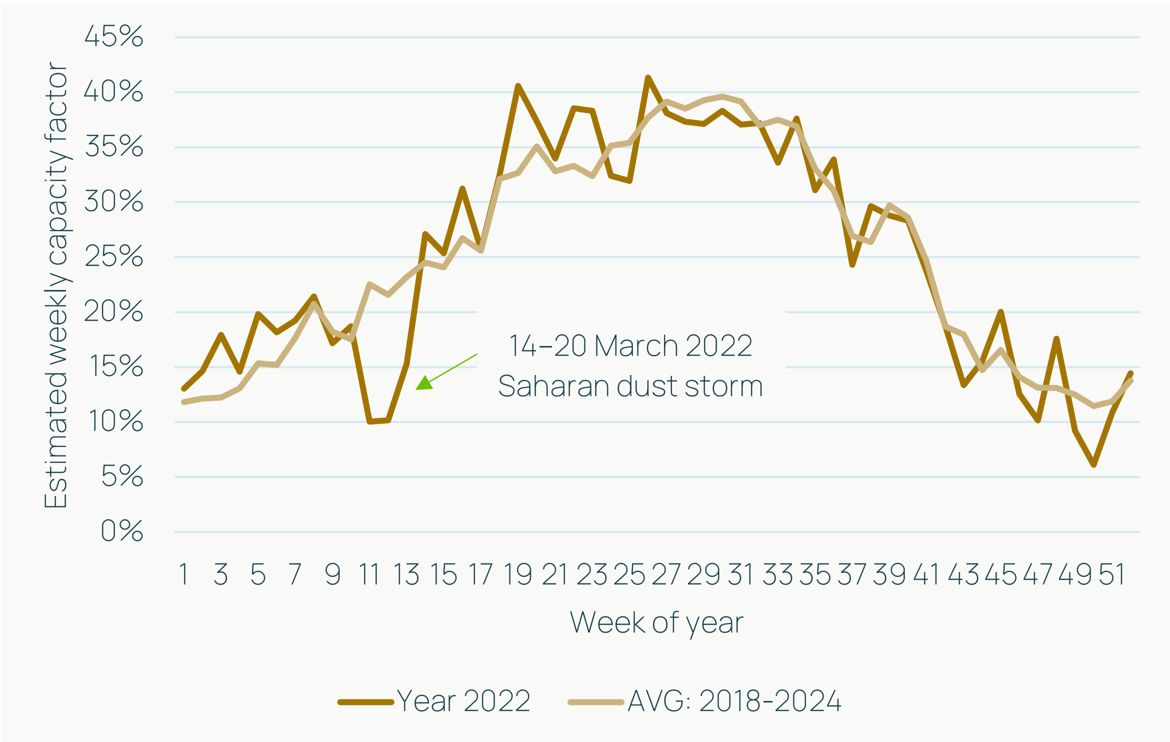

Figure 24 A Saharan dust storm halved solar generation in Spain over the period of almost two weeks in 2022. Data source: energycharts.de

- Wildfires in California (2020) resulted in significant generation drop in case of solar-powered generation.

Another threat are wildfires that significantly impact PV generation, primarily through the emission of smoke and particulate matter that obstruct sunlight, thereby reducing solar panel efficiency. For instance, during the 2024 wildfires in the southwestern United States, California experienced a notable decline in solar power output. Despite a 28% increase (Gavin Maguire, 2024)in solar generation in the first half of 2024 compared to the previous year, solar output dipped below year-earlier levels in mid-July as thick smoke from spreading wildfires darkened the skies and dimmed solar generation. This reduction in solar generation occurred precisely when electricity demand peaked due to increased air conditioning use during the summer heat. To compensate for the shortfall, power producers were compelled to increase generation from natural gas-fired plants, potentially exacerbating air quality issues already compromised by wildfire smoke.

The 2019–2020 Australian wildfires caused widespread haze and particulate matter (PM2.5) emissions that significantly reduced PV generation across New South Wales. Data from 160 residential PV systems showed an average reduction in power output of 13% per 100 μg/m³ of PM2.5, with total energy losses estimated at 175 GWh during the wildfire period. Financial losses for rooftop and utility PV systems amounted to approximately $19 million USD. The impacts were most pronounced during the morning and evening hours due to the longer atmospheric path of sunlight, underscoring the potential benefits of incorporating battery storage to stabilize energy supply during these critical periods (Ford *et al.*, 2024).

Furthermore, the vulnerability of PV systems to wildfire smoke and atmospheric pollutants have been highlighted in case of other events:

- Canberra Wildfire Event (2014): A localized fire in Canberra led to a 27% peak reduction in PV output on a clear sky day, highlighting the acute impacts of smoke plumes on solar generation at specific sites (Ford *et al.*, 2024).
- Singapore Haze (2015): Wildfire-induced haze from neighboring Sumatra caused reductions in PV energy yield of 15–25% across ten monitored installations. This demonstrates the regional impact of wildfires on solar energy generation in urban and suburban settings (Nobre *et al.*, 2016).
- Delhi Air Pollution (2018): Although driven by urban haze rather than wildfires, air pollution in Delhi caused a 12.5% reduction in sunlight intensity per 100 μg/m³ of PM2.5, illustrating the broader applicability of findings on particulate matter and PV system performance (Peters *et al.*, 2018).
- California Wildfires (2018–2020): Wildfire smoke in California resulted in reductions of normalized PV generation ranging from 9.4% to 37.8%, depending on the PM2.5 concentration (50–200 μg/m³). Additionally, variations in the aerosol optical depth (AOD) caused yield reductions of 9–49%, showcasing the diverse impacts of atmospheric conditions during wildfire events (EIA, 2020).

Hydropower generation is inherently dependent on climatic and hydrological conditions. In wet years, abundant water resources lead to high generation potential, often resulting in surplus electricity. Conversely, during dry years, limited water availability constrains generation, creating challenges in meeting demand. Furthermore, the hydropower potential is determined by precipitation patterns and snow cover and consequently snow-melt during spring. The 2021 hydropower crisis in Brazil exemplifies these dynamics. The country faced one of its worst droughts in decades, leading to critically low reservoir levels and a significant reduction in hydropower output, which accounts for a large share of its energy mix. This necessitated emergency measures, including increased reliance on fossil fuels and costly imports to stabilize the grid (Augusto Getirana *et al.*, 2021). Similarly, between 2020 and 2023, the western United States faced prolonged drought conditions that adversely affected hydropower generation. Reservoirs such as Lake Mead and Lake Powell reached historically low levels (Figure 25), compromising the operational capacity of hydropower plants and raising concerns about the reliability of electricity supply in the region (EIA, 2024).

To mitigate the impacts of hydro-climatic variability, power systems often incorporate overcapacity in hydropower infrastructure, that is, they build more installed generation capacity (turbines, penstocks, and reservoirs) than would be needed under average conditions. During dry periods, when inflows are limited and reservoir levels are low, this overcapacity allows operators to make the most of the scarce water by generating at high efficiency whenever water becomes available. It also enables better timing of water releases, allowing plants to generate during peak demand hours even if total annual generation is reduced. In effect, overcapacity provides firm capacity from limited resources, improving adequacy and operational reliability even when energy volumes are low.

However, this approach comes with economic and operational trade-offs. In wet years, when water availability is abundant, the system may not be able to use all of it due to limited demand or grid constraints. This leads to underutilization of infrastructure (spilled water, idle turbines) and potential loss of renewable energy. Furthermore, maintaining unused capacity involves capital and operational costs that may not be justified if extreme droughts are rare.

To address these challenges, systems must move beyond static capacity expansion and adopt more flexible planning frameworks. This includes investing in complementary technologies—such as wind, solar, and energy storage—improving inter-regional transmission, and using seasonal forecasting and adaptive reservoir management to optimize dispatch under uncertain inflows. Overcapacity can be a valuable hedge against drought, but it must be embedded within a broader, more dynamic resilience strategy to be effective and economically viable.

Strategies include diversifying the energy mix by integrating renewable sources like wind and solar to complement hydropower, developing advanced energy storage solutions such as pumped hydro storage or batteries to manage supply fluctuations, and strengthening regional and cross-border grid interconnections to facilitate energy exchange during periods of surplus or deficit. Understanding and planning for the interannual variability of hydropower resources are crucial for developing robust power systems capable of withstanding both dry and wet years. By employing comprehensive strategies that incorporate flexibility, diversification, and regional cooperation, energy systems can better withstand the challenges posed by hydrological variability and ensure a stable electricity supply. Drought/dry periods apart from impacting directly hydropower generation may threaten the operation of cooling systems of thermal generators and hinder coal transport via waterways.

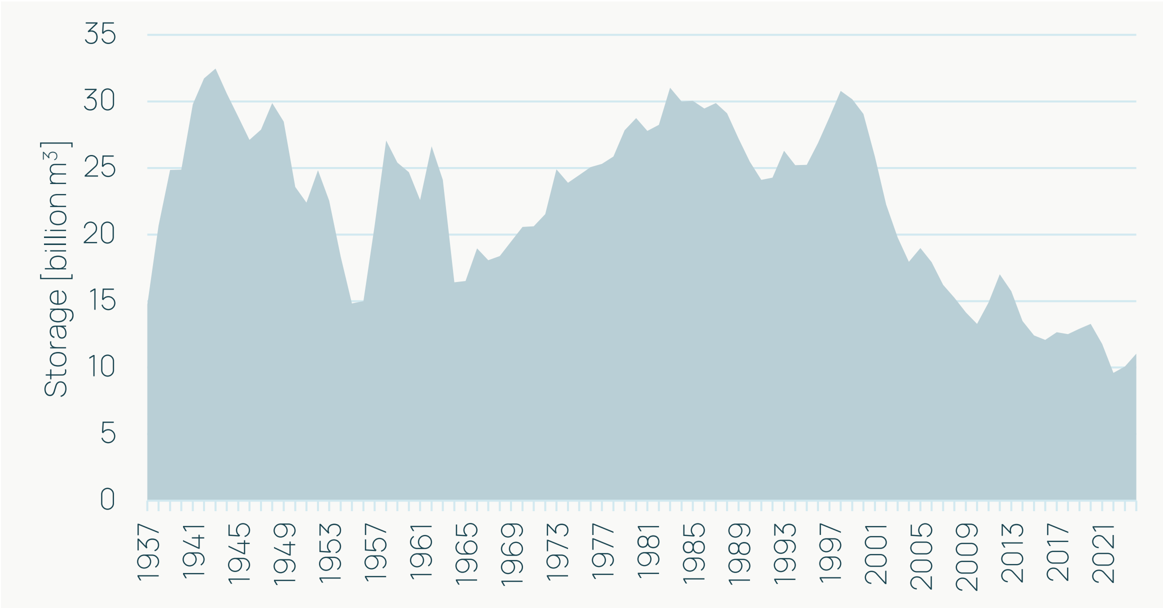

Figure 25. Lake Mead storage state of filling over the last decades.

Furthermore, as noted by (van der Most *et al.*, 2024b, 2024a) the so called compounding droughts pose a significant challenge to hydropower-dependent energy systems, where sequential and interconnected meteorological conditions amplify the severity and duration of energy shortages. These events are characterized by the simultaneous occurrence of multiple adverse weather conditions, creating a cascade of impacts on energy generation and demand. The interplay between low water inflows, reduced snowpack, and elevated temperatures exacerbates reservoir depletion and heightens energy insecurity. Recent research has identified three temporally compounding conditions critical to understanding energy drought dynamics in hydropower-reliant systems:

Spring-to-Summer Transition: A warm winter with reduced snowfall leads to diminished spring snowmelt, which, combined with a meteorological drought in spring, reduces water inflows into reservoirs. Dry subsoil further exacerbates the situation, increasing the likelihood of an exceptionally hot summer with heightened cooling demands. These conditions can quadruple the probability of summer energy droughts, particularly in Southern Europe, as observed in Italy's Po River basin during the 2022 drought (Chelli, 2023).

Autumn-to-Winter Persistence: In regions like Switzerland, low reservoir replenishment during spring, combined with persistent high-pressure systems in autumn and winter, elevates the risk of winter energy droughts. Such conditions were observed across Europe during the 2021 energy crisis, where low wind speeds and reduced hydropower generation coincided with high heating demand.

Multi-Year Feedback Loops: Drought conditions persisting over multiple seasons or years create a reinforcing cycle of low water inflows and high residual energy demand. For example, dry winters in Northern Europe often lead to decreased spring runoff, prolonging reservoir depletion and exacerbating energy deficits in subsequent years.

Compounding droughts highlight the critical need for resilient energy systems capable of anticipating, adapting to, and mitigating cascading impacts from interconnected meteorological extremes that strain hydropower and renewable energy generation.

Furthermore, in planning resilient and robust power systems, global phenomena must be considered as they can significantly influence renewable energy generation and infrastructure. For example, global terrestrial stilling—a decline in wind speeds observed globally in recent decades—poses a challenge for wind power generation. However, as reported by Zeng *et al.* (Zeng *et al.*, 2019) this trend has recently reversed, with implications for long-term wind energy forecasts. However, concerning the future resilient power system additional global phenomena should be closely monitored such as: oceanic and atmospheric oscillations, arctic amplification and melting ice and rising sea levels.

Compounding droughts across solar, wind, and hydropower resources—also referred to as compound renewable energy droughts—pose a growing challenge for power system planning and operation, particularly under increasing climate variability and extremes. Recent studies have highlighted that periods of co-occurring low renewable generation, spanning multiple technologies and regions, are more common and more severe than previously assumed (You *et al.*, 2025). Such compound events can significantly reduce the availability of variable renewable energy (VRE) over weeks to months, straining system adequacy, stressing storage and backup generation, and increasing reliance on fossil-based reserves. In hydropower-dependent regions, multi-year low inflow periods can coincide with solar and wind deficits, especially under persistent high-pressure systems that suppress both wind and cloud cover variability (You *et al.*, 2025). These events are difficult to capture with conventional power system models that typically rely on historical weather years or average weather scenarios, underestimating the frequency and impact of low-generation extremes.

A recent research emphasizes the need to integrate multi-decadal to century-scale weather data and compound event analysis into system models to better quantify the risks of energy droughts (van der Most *et al.*, 2024a). Without this, investment strategies may become biased toward oversimplified views of resource complementarity and overestimate system resilience. Furthermore, energy droughts can have economic consequences beyond adequacy, affecting market dynamics, curtailment patterns, and the operation of flexibility resources (Lei *et al.*, 2024). To address this, emerging modeling frameworks propose (Javed et al., 2023; Ruggles et al., 2024) stress-testing long-term capacity expansion plans under compound drought conditions and designing systems that are not only robust to historical variability but also resilient in the face of plausible future extremes.

Multiannual variability of wind resources is a crucial but often underrepresented factor in power system planning. While global terrestrial stilling—the observed decline in surface wind speeds from around 1980 to 2010—previously raised major concerns about the future of wind energy, more recent evidence suggests a partial reversal of this trend since 2010, with wind speeds recovering over many land regions (Zeng *et al.*, 2019). Nevertheless, this global recovery masks substantial regional variability, where some areas continue to experience decreasing or fluctuating wind conditions, particularly at decadal scales (Hueging *et al.*, 2013). This poses a critical challenge for power system models that rely on historical wind profiles or short-term variability datasets to simulate generation patterns. Without incorporating multiannual and decadal wind variability, system planners risk underestimating both the probability of extended low-wind periods and the associated need for storage, backup generation, or diversified portfolios.

Moreover, large-scale ocean-atmosphere oscillations such as the Pacific Decadal Oscillation (PDO) and North Atlantic Oscillation (NAO) have been shown to modulate regional wind speeds and can lead to synchronized low-generation conditions across wide areas (Zeng *et al.*, 2019). Traditional modeling frameworks, focused on "average year" or "typical meteorological year" approaches, systematically miss these risks. Recent research calls for stress-testing renewable-based systems against historical and synthetic sequences that capture such compound and multiannual droughts (van der Most *et al.*, 2024a). To better anticipate vulnerabilities, next-generation capacity expansion and dispatch models must explicitly represent the likelihood of multi-year wind shortfalls and integrate insights from large climate mode teleconnections. In this context the climate mode teleconnections refer to large-scale climate patterns that influence weather conditions—such as wind, solar radiation, and temperature-across vast regions, often far from where the pattern originates. These modes operate on seasonal to multi-year timescales and can cause synchronized anomalies in renewable energy resources, leading to widespread underperformance (or overperformance) of wind or solar generation. Only by moving beyond stationary weather assumptions can future power systems be made genuinely robust and resilient to the full range of plausible wind variability scenarios.

7.3 Strategies for weather-resilient infrastructures

To mitigate the increasing risks associated with changing and compounding patterns of renewable resource availability, more sophisticated strategies beyond simple diversification are necessary. While hybrid renewable systems—such as combined wind and solar farms—can still provide significant benefits by exploiting complementary generation profiles (e.g., solar peaking in summer and wind often being stronger in winter in Europe), recent research shows that compound renewable energy droughts can simultaneously suppress both wind and solar outputs over weeks to months (You *et al.*, 2025). Therefore, hybridization alone cannot guarantee system adequacy under extreme weather variability.

A key mitigation measure is the integration of clean firm power sources—such as hydrogen-ready gas turbines, geothermal, nuclear, fossil power plants with CCS, or bioenergy plants—that can provide dispatchable, low-carbon electricity during extended renewable droughts. Clean firm resources complement variable renewables by offering guaranteed capacity during low-generation events without depending on favorable weather, thus substantially improving system resilience against correlated multi-technology shortages. Their role becomes even more critical when considering the potential for multiannual anomalies in wind patterns, as emerging evidence points to significant decadal oscillations and persistent low-wind periods in some regions (Hueging *et al.*, 2013).

Enhancing regional interconnection remains an important strategy to smooth out spatial generation variability, but its effectiveness during widespread and synchronized droughts may be limited. As such, investment in both short-term and long-duration energy storage becomes necessary. Recent studies suggest that to reliably manage events like the severe VRE droughts observed in 1996–1997, the European Union would require an additional 50 to 170 TWh of energy storage beyond existing plans (Kittel *et al.*, 2024). However, achieving such large storage capacities entails very high system costs, especially for long-duration solutions capable of covering multiweek deficits.

Thus, planning frameworks must shift from optimizing for average conditions toward robustness and resilience under extreme events. Stress-testing system designs against compound, persistent, and widespread renewable energy droughts is essential. Cost-effective resilience can be achieved not by maximizing storage alone, but by strategically combining variable renewables with clean firm power, targeted interconnection upgrades, and enhanced forecasting systems that incorporate decadal climate oscillation trends (van der Most *et al.*, 2024a).

Ultimately, designing a future-proof power system will require recognizing that climate-driven resource variability and extreme events are not outliers but fundamental features of the energy landscape. This necessitates moving beyond traditional least-cost planning to frameworks that balance cost, adequacy, and resilience under deep uncertainty.

8 Security and defense

This section explores the energy security and defense-related aspects of maintaining power system resilience, focusing on physical and cyber threats. It also discusses the importance of collaboration between energy sectors and national security agencies to enhance protective measures.

8.1 Wind project siting and security concerns

Defense-related constraints, such as military radar interference and restricted land use, significantly impact the development of VRE projects. These constraints can introduce hidden costs, including project delays and increased siting expenses. Wind turbines can disrupt radar systems due to their large and moving blades, which reflect electromagnetic signals and create clutter on radar screens. This interference complicates the detection and tracking of airborne objects, posing national security concerns (Roithner *et al.*, 2024).

- In November 2024, the Swedish government blocked 13 wind farm developments in the Baltic Sea, citing concerns that they could provide cover for potential attacks, thereby highlighting the conflict between national security and renewable energy expansion (Reuters, 2024).
- The proposed Lava Ridge Wind Project in Idaho faced opposition due to its proximity to the Minidoka National Historic Site and potential interference with military radar systems. Concerns about visual and auditory impacts, as well as disruptions to radar operations, led to significant project modifications, including reducing the number of turbines and altering their placement (Department of the Interior, 2024).
- In Finland, the development of onshore wind projects near the eastern border has faced significant opposition from the Finnish Armed Forces due to concerns over defense and national security. Military officials argue that wind turbines can interfere with radar systems, compromising their ability to monitor airspace and detect potential threats. These constraints have led to delays in project approvals and increased costs for wind developers, who must often negotiate solutions or consider alternative sites further from sensitive defense installations (National Wind Watch, 2022).

8.2 Energy security and geopolitics

8.1 New infrastructure

Subsea cables, responsible for transmitting 99% of intercontinental internet traffic, are vital to global communications and energy systems. However, they are susceptible to both natural hazards and deliberate sabotage. Recent incidents have underscored these vulnerabilities:

- Sabotage in the Baltic Sea: In December 2024, the Estlink 2 power cable and several telecom lines between Finland and Estonia were damaged. Finnish authorities detained the Russian-linked oil tanker Eagle S, suspecting it of dragging its anchor to intentionally sever these cables. Such acts highlight the geopolitical tensions impacting critical infrastructure. (Mchugh, 2024)
- Chinese Vessel Activity Near Taiwan: In January 2025, a Chinese-owned vessel, Shunxing 39, reportedly severed an undersea fiber-optic cable near Taiwan. Taiwanese authorities

suspect sabotage, reflecting the island's vulnerability amid ongoing pressure from China (Wang, 2025).

These incidents demonstrate the strategic importance of subsea cables and the potential for state and non-state actors to exploit their vulnerabilities, posing significant risks to energy security and geopolitical stability.

8.2. Supply chains

Currently, the global supply and demand for fossil fuels represents a significant geopolitical concern. While reliance on imported fuels poses clear threats to supply security, the extraction and supply chains of critical minerals are expected to present similar geopolitical challenges in the future. Thus, the focus may transition to the geopolitics of critical materials, leading to a shift in the nature of international interdependencies. As noted by IRENA (Gielen, 2021) while reserves and resources of critical[3] materials are generally known, factors like societal acceptance, access to new mining projects, and geopolitical risks require deeper understanding to assess criticality. Sufficient resources exist, making long-term availability dependent on scaling production and diversifying supply. However, supply challenges for some critical materials remain significant until 2030, as indicated by recent price increases. Whether these issues are short-term disruptions or long-term bottlenecks remains uncertain. Key concerns include the pace of mining and processing expansion, reserve availability, and geopolitical risks. The energy transition—driven by solar PV, wind, grid expansion, and electromobility—will sharply increase demand for critical materials, with implications varying by material, underscoring the need for tailored solutions. At the same time it is important to indicate that VREs do not rely on fuels, which substantially reduces long-term supply chain risks compared to fossil fuels-based generation. The market variability and consequently how it might impact the power system transformation fuelled by the availability of these resources is shown in Figure 26.

[3] Criticality is determined by factors such as the effort required for extraction, concentration of production in a few countries, declining resource quality, the need for a significant supply ramp-up, and large price fluctuations driven by supply-demand imbalances.

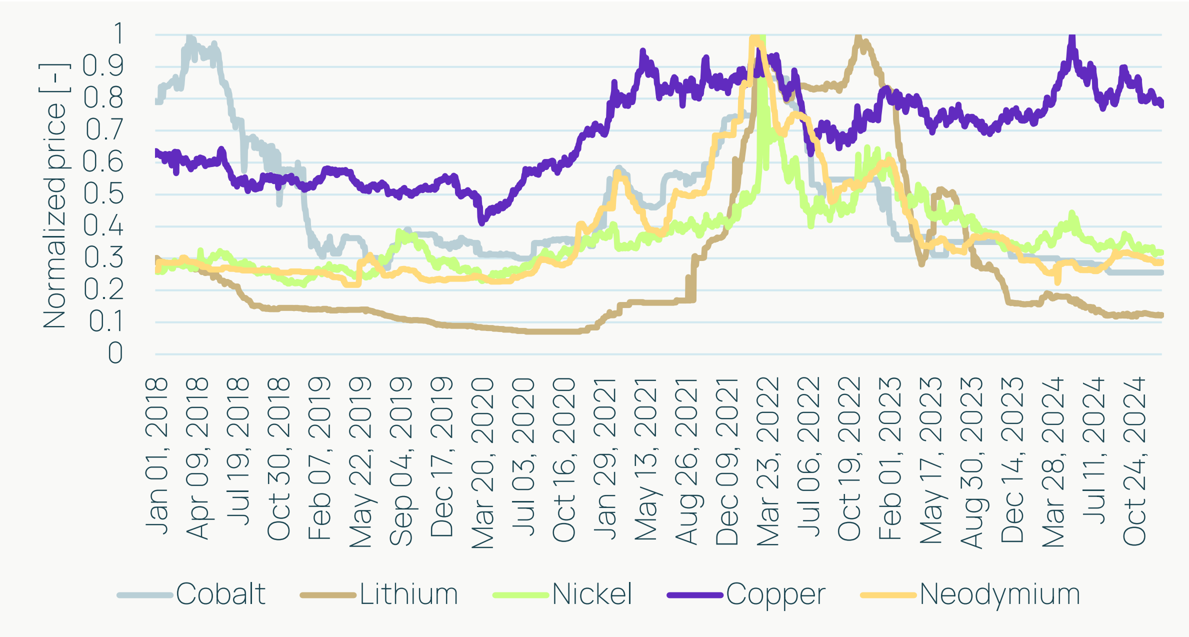

Figure 26. Critical elements price variability over the years 2018-2024 (Daily Metal Prices, 2024).

Table 11 highlights key considerations for critical materials essential to a future carbon-neutral and resilient power system, emphasizing their role in supporting energy transitions. It assesses materials like copper, lithium, nickel, cobalt, and rare earth elements (REE) across dimensions crucial to sustainability and resilience.

Table 11. Clean energy transition risk assessment as per International Energy Agency, source: (IEA, 2024c).

Ancillary service	Supply risk	Geopolitical risk	Barriers to respond to supply disruption	ESG and climate risk exposure
Copper	The gap between the current project pipeline and the mining requirements needed to meet the 2035 APS[4] targets.	Diversified	Market is mature with substantial supply from secondary sources.	Mines (52%) are located in high water stress areas.
Lithium	Very high price variability compared to other minerals	As by 2030 85% of the refining capacity is projected to be in three countries.	Only 3% of lithium is sourced from secondary sources.	A 50% of the mines are situated in arid areas.
Nickel	Contributes to 6% of battery pack cost as of 2023	In 2030 61% of mining will be realized in a single country.	Recycling rate is very low and roughly 1% of nickel comes from secondary sources.	Very high refining grid related carbon intensity, exceeding 600 g of CO2/kWh.

[4] Announced Pledges Scenario

Ancillary service	Supply risk	Geopolitical risk	Barriers to respond to supply disruption	ESG and climate risk exposure
Cobalt	16% shortfall in the current project pipeline compared to the mining requirements needed to meet the 2035 APS targets	84% of mining will be realized in single country by 2030.	Low-cobalt chemistries are attracting attention showing potential to reduce its demand.	Mining activities often demonstrate low environmental and social preference.
REE	High price volatility	77% of refining in a single country by 2030.	Pricing schemes in mining often lack transparency.	High average grid carbon intensity for refining

The transition to resilient and carbon-neutral power systems depends on reliable access to critical minerals like lithium, cobalt, nickel, and rare earth elements, which are essential for renewable energy technologies such as batteries, solar panels, and wind turbines. These resources are unevenly distributed globally, leading to significant trade dependencies that necessitate well-structured and adaptive trade relationships. The growing demand for critical minerals, driven by the rapid adoption of renewable energy technologies, highlights the importance of international trade frameworks. Initiatives such as the European Raw Materials Alliance (ERMA) and the Minerals Security Partnership aim to address supply vulnerabilities by fostering international collaboration and investments in sustainable supply chains. These efforts are vital for diversifying supply sources and mitigating geopolitical risks (Kirsten Hund *et al.*, 2020) (IEA, 2021). Geopolitical concentration of critical mineral production highlights supply chain vulnerabilities. For example, China dominates the global refining of lithium and rare earth elements, accounting for over 80% of global production for certain materials. Such concentration increases exposure to potential supply disruptions and price volatility, necessitating diversification through trade agreements like the EU-Chile Free Trade Agreement (European Commission, 2020). Furthermore, national policies aimed at controlling critical mineral resources, such as export restrictions or resource nationalization, further complicate trade dynamics. Countries like Indonesia and Zimbabwe have implemented restrictions on raw material exports to prioritize domestic value addition. While these policies support local economic development, they can create bottlenecks in global supply chains if not aligned with international trade frameworks (Srivastava, 2023; UNCTAD, 2017).

In conclusion, dynamic and equitable trade relationships are critical to the development of resilient and carbon-neutral power systems. Trade agreements, multilateral partnerships, and sustainable practices are essential to addressing supply risks, reducing geopolitical dependencies, and ensuring fair access to critical minerals. These measures must be supported by transparent and enforceable frameworks that align with global energy transition goals.

8.3 Impact of distributed generation

Distributed energy resources (DERs) represent a shift away from large, centralized generation assets toward multiple smaller, decentralized sources, significantly reducing the impact of single-component failures. Additionally, when electricity is generated and consumed locally, such as through solar PV combined with battery storage in energy communities, or small modular reactors

(SMRs) serving industrial hubs or data center clusters, it reduces dependence on the broader transmission network, marking a departure from traditional centralized grids.

However, while distributed generation (DG) offers clear advantages, it substantially increases the number of individual generating units, leading to exponential growth in system interactions and greater demands for grid communication and coordination. Coordinating numerous small generating units rather than a few large ones demands advanced communication technologies, which, while beneficial, also expose the grid to heightened cybersecurity risks. Moreover, sources like rooftop solar often cause frequent voltage fluctuations, requiring robust voltage management strategies. Furthermore, DG introduces bidirectional power flows, complicating protection systems, making fault detection and clearing more challenging, and increasing overall grid management complexity.

9 Environmental and social impacts

This section addresses the environmental consequences associated with power system operations and resilience measures. It discusses lifecycle impacts, potential conflicts between resilience efforts and environmental goals, and ways to mitigate such issues.

9.1 Lifecycle environmental assessments of power systems

When looking at various power generation technologies the lifecycle assessment calls for evaluating the energy inputs required to manufacture, maintain and decommission them. Although renewable energy sources such as solar PV and wind turbines energy consumption during the operational life are minimal, their manufacturing is an energy intensive process. In contrast, fossil fuel technologies primarily require materials for fuel extraction during the operational phase. Nuclear energy, however, has fuel-related material demands that are orders of magnitude lower due to its high energy density, resulting in one of the lowest overall resource footprints, even when considering construction and decommissioning phases (UNECE, 2022).

Currently, there are two metrics have been proposed to address the environmental impact issue:

- Energy Payback Time (EPBT) refers to the time required for a generator to generate the amount of energy equivalent to what was consumed during its production, installation, and maintenance.
- Energy Return on Energy Invested (EROEI) is a ratio that measures the total energy output of a system over its operational lifetime relative to the energy input required to develop and maintain it. A higher EROEI indicates a more energy-efficient system.

The values of the first one are summarized in Table 12 and as it can be seen in particular for irradiation-based technologies (solar PV and concentrated solar) they exhibit a significant range. This mostly results from technology manufacturing energy demand intensity (ex. thin film PV vs monocrystalline PV) or regions where they were tested (ex. High vs low irradiation). Consequently, as it can be observed the PV would score quite low when on energy return on energy invested index especially when the power system integration costs are accounted for (Jurasz *et al.*, 2020). In such circumstances it is important to identify if from a global perspective the energy source does not in the end become an energy sink instead of a source. As shown on an off-grid case study (Jurasz *et al.*, 2020)a highly reliable solar PV-battery system despite its perceived carbon neutrality due to its oversized capacities had an estimated CO2 emissions at 300 g CO2/kWh.

Table 12. Energy payback time for selected technologies, adopted from source EPBT (IPCC, 2011) and lifetime estimates based on source (IEA, 2020):

Technology	EPBT - Low value	EPBT - High value	Lifetime (years)
Brown coal	1.9	3.7	40
Natural gas	1.9	3.9	30
Nuclear (heavy water reactors)	2.4	2.6	60
Nuclear (light water reactors)	0.8	3.0	60

Photovoltaics (PV)	0.2	8.0	25
Concentrated solar	0.7	7.5	25
Wind turbines	0.1	1.5	25
Hydropower	0.1	3.5	80

However, as noted by Raugei metrics like EROEI are valuable for assessing the net energy profitability of energy supply chains (Raugei, 2019). However, their application must be approached with caution. Direct comparisons between energy carriers can be misleading, as they often involve fundamentally different supply chain processes and end-use applications. Additionally, calculations often vary significantly based on system boundaries, assumptions about energy quality, and additional energy investments required for processes like refining or transportation. Simplistic aggregation of EROEI values into averages or benchmarking against fixed 'minimum' values risks oversimplifying the diverse realities of energy systems. It is critical to use consistent approaches/methods and align calculations to specific energy carriers and their practical usability at the point of use to derive meaningful insights.

On top of that it is important to underline what has observed by Lambert (Lambert *et al.*, 2014). Societies with high EROEI values and greater energy per capita generally exhibit better social indicators, such as higher Human Development Index (HDI), improved literacy, and better access to healthcare and clean water. Declining EROEI, particularly for fossil fuels, poses risks for both developed and developing nations, necessitating shifts to alternative energy sources with sufficient EROEI to sustain societal functions. Furthermore, developing nations with lower EROEI for imported energy face challenges in maintaining economic and social stability, exacerbated by dependency on fossil fuels.

The above presented concepts are subject of ongoing academic discussion thereby and considering discrepant opinions of various experts a holistic approach in case of solar PV and wind energy should be considered. Concluding, while EPBT and EROEI are commonly used indicators to quantify the energy efficiency of power generation technologies from a lifecycle perspective, their practical relevance in system-level decision-making is limited. These metrics do not account for temporal, spatial, or systemic constraints, such as when energy is produced, how it aligns with demand, or how infrastructure interacts within a larger power system. Therefore, although EPBT and EROEI may offer useful benchmarks for material or energy accounting, they should not be interpreted as comprehensive indicators of sustainability, economic value, or grid integration suitability.

Table 13. Life cycle emissions per kWh of electricity generated from different source, based on (IPCC, 2018).

Technology	Life cycle CO_2 equivalent emissions	Social cost of carbon (assuming $185 per ton CO_2)
Coal (pulverized)	820 kg/MWh	$152/MWh
Gas (CC)	490 kg/MWh	$91/MWh

Biomass	230 kg/MWh	$43/MWh
Utility solar photovoltaic (PV)	48 kg/MWh	$9/MWh
Rooftop solar photovoltaic (PV)	41 kg/MWh	$8/MWh
Geothermal	38 kg/MWh	$7/MWh
Concentrated solar power (CSP)	27 kg/MWh	$5/MWh
Hydropower	24 kg/MWh	$4/MWh
Wind offshore	12 kg/MWh	$2/MWh
Nuclear	12 kg/MWh	$2/MWh
Wind onshore	11 kg/MWh	$2/MWh

Lifecycle assessment (LCA) is a widely accepted methodology used to evaluate the total environmental footprint of power generation technologies by accounting for emissions and resource use throughout their entire lifecycle, from raw material extraction and manufacturing, to operation, maintenance, and eventual decommissioning. Table 13 provides a comparative overview of the lifecycle CO_2-equivalent emissions for different electricity sources, as estimated by the IPCC (2018), along with the associated social cost of carbon based on a valuation of $185 per ton CO_2. It is evident that fossil fuel-based technologies, particularly coal and natural gas, incur disproportionately high lifecycle emissions and external costs, whereas renewables such as wind, solar, and hydropower exhibit significantly lower climate impacts per MWh generated.

While lifecycle emissions per kWh are a useful benchmark for comparing technologies, they offer only a partial picture when evaluating energy systems. LCA metrics do not account for critical attributes such as temporal variability, firm capacity, land-use intensity, or material supply risks, all of which play a key role in shaping the sustainability and resilience of a power system. For example, a technology with low lifecycle emissions may still pose challenges for system integration due to variability (e.g., solar PV), long build times (e.g., nuclear), or region-specific environmental concerns (e.g., hydro in ecologically sensitive areas). Therefore, integrating LCA results with broader system-level analyses is essential for capturing trade-offs between emissions, grid stability, energy security, and long-term decarbonization goals. Furthermore, a holistic power system evaluation must go beyond emissions alone and consider the dynamic interactions between generation, transmission, storage, and demand-side flexibility. Technologies with similar lifecycle emissions can contribute very differently to system adequacy and cost-effectiveness depending on how and when they produce energy. Wind and solar, for instance, have low operational emissions, but require complementary infrastructure—such as long-duration storage, demand response, and grid expansion—to fully realize their decarbonization potential without compromising reliability. By integrating lifecycle assessment with techno-economic modeling and system integration analysis, planners can better account for not only the carbon footprint of energy sources, but also their broader implications for sustainable power system design.

9.2 Trade-offs between resilience and environmental protection

This subsection investigates the investment in resilience measures intersects or conflicts with environmental objectives.

- Overbuilding of VRES and Land Use Implications

Overbuilding Variable Renewable Energy Systems to enhance resilience introduces significant environmental challenges. Large-scale deployment of wind and solar infrastructure often requires extensive land use, leading to habitat disruption, biodiversity loss, and changes to local ecosystems. For example, utility-scale solar projects can alter soil composition and affect water cycles, while onshore wind farms may disturb wildlife and migration patterns (Turney and Fthenakis, 2011). These ecological impacts highlight a critical trade-off: increasing energy system resilience through overbuilding VRES may undermine environmental protection goals, particularly in sensitive or high-value conservation areas (Gasparatos *et al.*, 2017). Balancing these competing priorities demands strategic site selection and integration of technologies that mitigate ecological harm.

- Energy Storage vs. Resource Extraction

The increased deployment of energy storage systems, such as lithium-ion batteries, to support VREs necessitates the extraction of materials like lithium, cobalt, and nickel. These mining activities can lead to environmental issues, including habitat disruption, water contamination, and elevated greenhouse gas emissions during extraction and processing. While these storage solutions enhance grid resilience by mitigating VREs intermittency, their associated environmental impacts may conflict with broader ecological objectives. Closed-loop pumped storage hydropower (PSH) presents a more sustainable alternative. Unlike traditional open-loop systems, closed-loop PSH operates independently of natural water bodies, thereby reducing potential impacts on aquatic ecosystems. Studies (Saulsbury, 2020) indicate that closed-loop configurations can minimize aquatic and terrestrial impacts, offering greater siting flexibility and localized environmental effects.

- Firm Generation: Hydropower vs Environmental Integrity

Hydropower, as a firm and flexible low-carbon resource, plays a crucial role in improving system resilience, yet it often comes at a substantial ecological cost. Large dams disrupt riverine ecosystems—impeding fish migration, altering sediment transport, and fragmenting habitats—which has caused marked biodiversity declines in regions like the Mekong, where over 60% of rivers are already fragmented (Twardek *et al.*, 2022). Moreover, reservoirs commonly flood extensive land areas, leading to deforestation and displacement of communities, as documented in global cases including China's Three Gorges Dam and Laos hydropower projects.

- Grid Expansion: Transmission Infrastructure and Environmental Cost

Investments in grid resilience, via enhanced transmission lines and grid infrastructure, are essential in integrating VRE and distributing firm generation, but such expansion is not without environmental trade-offs. Overhead transmission corridors can fragment forests, threaten biodiversity corridors, and face local resistance over visual and land-use concerns . While underground cables or co-located routes (e.g., along existing roads or railways) can reduce impacts, they significantly raise costs and technical complexity. Therefore, resilience-focused grid investments must be coupled with strategic spatial planning, stakeholder consultation, and minimization design principles to mitigate ecosystem disruption while ensuring robust and decarbonized electricity delivery.

9.3 Environmental risks associated with nuclear energy

Although the EU Joint Research Centre (JRC) considers modern nuclear energy the safest energy source available (Abousahl *et al.* 2021), societal perceptions may differ. In reality, no technology is entirely risk-free, and nuclear energy is no exception. The management of radioactive waste from spent nuclear fuel has historically been a significant concern. However, the JRC concludes that radioactive waste can be safely managed in ways that responsibly consider future generations. Furthermore, next-generation nuclear reactor technologies have the potential to recycle spent nuclear fuel into new fuel and valuable byproducts, transforming radioactive waste into an asset rather than a liability, and simultaneously reducing its overall volume.

Similarly to the JRC, the UNECE's 2022 report (UNECE, 2022) on life-cycle assessment of electricity sources finds that nuclear energy ranks among the lowest in terms of resource consumption, land use, and emissions, indicating that it has one of the smallest overall environmental impacts.

Finally, with regards to costs nuclear power producers are generally financially responsible for storage of waste. These components are included in the technology cost assumptions of nuclear power (Qvist Consulting, 2020).

9.4 End-of-horizon effects and unintended consequence

This subsection will investigate the unintended consequences of renewables deployment.

Ex. traditional industry in Norway competing with data centers (DC), DC lowering variability of prices but not the price level itself impacting the other customers (Andersen, 2013), as well as reducing environmental footprints while maintaining system resilience (Nøland *et al.*, 2022). The "end-of-horizon" concept in power system modeling means how constraints or goals defined at the modeling time horizon (e.g., a *hard cap* for achieving decarbonisation by 2050) shape decision-making. When such caps are imposed, the model tends to prioritise long-term solutions like hydrogen combustion, which can serve as a flexible, zero-carbon but likely very costly energy source to meet residual demand and ensure system reliability in the final stages of decarbonization. This approach can introduce biases favouring technologies that align with end-of-horizon requirements rather than intermediate-stage optimization.

- Is Solar/wind pushing out hydropower development? A recent integrated modeling Angelo Carlino *et al.*, 2023) of Africa's future power systems reveals that the declining costs of solar and wind technologies, combined with growing concerns over hydroclimatic variability, are significantly curbing the economic attractiveness of hydropower expansion. The study finds that between 32% and 60% of proposed hydropower projects across the continent are not cost-optimal under any scenario considered, and that nearly all new hydropower development is expected to stall after 2030. Although hydropower remains a valuable transitional technology, especially for displacing coal in the near term, its long construction times, vulnerability to drought, and social and environmental impacts weaken its competitiveness compared to rapidly deployable solar and wind systems. However, since solar and wind are inherently variable, their expansion does not eliminate the need for flexibility—it instead shifts the challenge to designing systems with adequate balancing resources such as storage, demand response, and regional interconnections. Thus, while variable renewables are displacing large-scale hydropower as the dominant source of new capacity, the long-term success of this transition depends on building power systems that can remain reliable without hydropower's traditional role in firm and dispatchable generation.

9.5 Social externality

The social cost of carbon (SCC) represents a significant blind spot in conventional LCOE approaches. The SCC represents the economic damage caused by each additional ton of carbon dioxide emissions, encompassing factors such as climate change impacts on agricultural productivity, human health, and property damage from increased natural disasters (Tol, 2023). Recent studies have shown that SCC estimates have increased over time, reflecting a growing understanding of the severe and long-term consequences of carbon emissions. Ricke *et al.* (Katharine Ricke *et al.*, 2018) demonstrated that the true global SCC approaches $417 per ton of CO2, far exceeding previous estimates. The Interagency Working Group on Social Cost of Greenhouse Gases (US Government, 2021) suggested these costs could range from $17 to $83 per metric ton of CO2 in 2025 and may rise to $ 32 - 116, depending on the discount rate used. Tol showed that in the past 10 years, estimates of the social cost of carbon have increased from $9 per tCO_2 to $40 per tCO_2 for a high discount rate and from $122 per tCO_2 to $525 per tCO_2 for a low discount rate (Tol, 2023). The SCC calculations vary across different studies depending on underlying climate model, choice of methods, assumptions, geographical scopes, and perspectives. Despite the variability in exact figures, ranging from tens to hundreds of dollars per ton of CO_2, all estimates consistently highlight a significant level of economic and social costs associated with carbon emissions that LCOE is not able to count and the urgent need to internalize these costs into decision-making.

This dramatic undervaluation has cascading effects across multiple sectors. For instance, Ortiz-Bobea *et al.* showed in their study that climate change has already reduced global agricultural productivity by approximately 21% since 1961, with projections suggesting accelerating losses in coming decades (Ortiz-Bobea *et al.*, 2021). These agricultural impacts connect directly to food security and economic stability in ways that LCOE calculations simply cannot capture.

The deployment of energy projects can have significant effects on local employment, both positive and negative. For instance, the construction and operation of renewable energy facilities may create jobs in certain regions, while fossil fuel-based projects might lead to job losses in others. However, these labor market dynamics are not reflected in LCOE calculations, which focus solely on the direct costs of energy production. This omission means that the broader socio-economic impacts of energy projects on local communities are overlooked and potentially lead to suboptimal policy and investment decisions.

The spatial distribution of social impacts presents another crucial dimension often overlooked in system planning. Comprehensive work by Dröes and Koster (Dröes and Koster, 2021) examined how different energy choices affect property values, community development patterns and social cohesion. Their research reveals complex interactions between energy systems and local social structures that extend far beyond simple economic metrics such as LCOE. These findings align with studies by (Carley and Konisky, 2020) showing how specific communities and socio-economic groups can become winner or losers and diminish the justice and equity dimensions of the transition.

These insights point toward the need for more sophisticated evaluation frameworks that can account for both direct and indirect effects while considering complex temporal and spatial distributions of impacts across different communities and social groups.

10 Technology maturity risks

This section addresses the gaps in understanding of the technology readiness level (TRL) risks of potentially enabling technologies for the stationary energy applications. Understanding these risks is essential to plan for de-risking strategies in the energy transition. We have deliberately focused on technologies grid-forming inverters, battery storage, hydrogen storage and nuclear reactors as a mean to limit scope.

10.1 Grid-forming (GFM) inverter technology

Inverters that interface the macro-scale power grid with solar, wind, batteries, and HVDC interconnectors can be equipped with grid-forming (GFM) technology. The GFM technology has achieved full maturity (TRL9) in niche contexts such as microgrids and is rapidly advancing in supportive roles within large-scale power systems in hybrid configurations at the pilot-to-commercial stage (roughly TRL7-9). In contrast, as a standalone backbone solution, GFM inverters are not yet ready for prime time in large grids. This scenario remains at TRL 5–6, with only small-scale demonstrations indicating feasibility.

GFMs are configured to emulate the inherently stable characteristics of synchronous generation facilities such as hydropower and nuclear power plants, thus, they are called virtual synchronous machines. However, while GFM technologies have been successful in running microgrids, there are significant challenges to making them ready as a standalone solution in macro-scale power systems with high shares of inverter-based generation and storage. The GFM technology is currently transitioning from research and development projects into pilot projects to enable broader implementation in several applications. Nevertheless, there is still a lack of standardized definitions and performance requirements in grid codes that hinder harmonized solutions across different regions (ENTSO-E, 2019). In fact, the majority of inverter-based installations are still based on grid-following (GFL) inverters (Ramamurthy *et al.*, 2023). Moreover, the incentives for GFM are related to the current practices, where inverter-based generation is curtailed up to a certain level as it is currently challenging to run a large-scale grid entirely on inverters alone. However, in order to run a power system only on inverters, it is not enough to just provide some of the system-bearing services, but all of them.

GFMs today can provide a short-circuit current 10 to 30 percent above the nominal, while synchronous resources can provide 500 to 700 percent (Kroposki and Hoke, 2024). Inevitably, a GFM-based grid is weaker than a synchronous-based and it might become difficult to clear out faults. Nevertheless, it is possible to over-dimension the power electronics to enhance the grid strength. However, it ends up becoming a significant cost driver. It is also important to consider that the periods of inverter-based resources exceeding 70 percent are limited, so these costs must be valued against the value of the standalone GFM supply and how much extra penetration it would allow. The incentives might be limited on that basis alone, and a market for system-bearing ancillary services must be established to create further incentives. However, in such a future ancillary market, GFM would compete with synchronous condensers (SynCons), who can provide a broader range of ancillary services, including noncontrolled physical inertia and short-circuit strength. As a result, they have been considered a mid-term solution to run power grids that lack synchronous production units (Nøland *et al.*, 2024a).

10.2 Battery storage technology

Batteries are devices that can store electricity in chemical form. They are considered a short-duration storage technology in power grids since they have a relatively higher power density in relation to their energy density. The battery installed electrical energy storage duration is today in the order of a few minutes to a few hours, while energy system models assume a significant upscaling, which should be critically assessed. A twenty-fold increase in Europe has been projected before 2031(Darmani, 2022).

10.2.1 Lithium-ion batteries: Lithium-ion dominates most sectors due to its versatility, proven performance, and long lifetime, and are the dominant grid-scale energy storage technology today (TRL 9). Nevertheless, it has limitations in achievable performance. As of 2023, the Moss Landing Energy Storage Facility in Monterey County, California, stands as the world's largest battery storage installation with a capacity of 750 MW / 3 GWh (Colthorpe, 2023). Nevertheless, this technology has a significant geopolitical challenge as 99 percent of the cheapest type of lithium iron phosphate (LFP) battery cells are now produced in China (Sanderson, 2024). Another risk is the fact that li-ion batteries rely on critical minerals expected to be in short supply by the end of this decade (Financial Times, 2023).

10.2.2 Flow batteries: These batteries have a complex system design and are currently not widely deployed, with a TRL spanning from 4 to 9, depending on the chemistry and design. As of 2024, the largest deployed flow battery is the Xinhua Ushi Energy Storage System (ESS) in Ushi, China, with a capacity of 175 MW / 0.7 GWh (Abhishek Bhardwaj, 2024). The most mature variants, notably vanadium redox flow and zinc-bromine flow batteries, have reached roughly TRL8–9, meaning early commercial systems are available and being deployed in pilot projects.

10.2.3 Solid-state batteries: Solid-state batteries are currently in the pre-commercial pilot-phase (TRL6), with substantial investments being directed toward research and development to improve the performance and scalability. Early-stage manufacturing efforts are ongoing with a particular focus on electric vehicles. In practical terms, no solid-state battery systems are yet deployed for grid-scale storage in Europe.

10.3 Hydrogen storage technology

In many energy system models, long-duration hydrogen storage has been shown to exhibit a significant benefit in helping integrate higher penetration of intermittent renewables. However, the supply chains and the technical deployment of the hydrogen infrastructure are still in their infancy, and a more thorough assessment must be made of technical and economic assumptions in energy system models. Hydrogen is produced using electrolysis but can be electrified using fuel cells or hydrogen-ready gas turbines. The combustion of hydrogen can in some cases lead to lower efficiency and non-CO_2 emissions but is easier to integrate into the macro-scale power system due to its synchronous generation characteristics.

10.3.1 Hydrogen storage: Compressed gaseous hydrogen (GH_2) storage is a fully commercial technology at TRL9 but due to physical limitations, it is best suited for small-to-medium size applications. On the contrary, liquid hydrogen (LH_2) storage is at the demonstration to early commercial phase (TRL8-9). Unlike GH_2, LH_2 has higher volumetric density but maintaining hydrogen in its liquid form is energy-intensive and boil-off evaporation makes it more suited for intermediate storage or transportation applications rather than as stationary long-duration energy storage. Ammonia (NH_3) is widely used for chemical purposes, while early demonstration of ammonia-fuelled gas turbines is underway (TRL6-7). NH3 is generally cheap to store but conversion inefficiencies adds significant costs for stationary energy storage applications. Finally, storing hydrogen in underground salt caverns is the most advanced large-scale H_2 energy storage method. Although it historically have demonstrated full commercial viability (TRL9) and are generally well understood, several European pilot projects are currently at TRL6-7. Salt caverns offer the lowest storage costs as it benefits from the economics of scale.

10.3.2 Hydrogen transportation: Purpose-built hydrogen pipelines have operated for decades (TRL) whereas large-scale repurposing of pipelines is still at pilot/demonstration stage (TRL7). Hydrogen cylinders and tanks are considered a mature, commercially available solution (TRL 9). Moreover, tube trailers are a commercially deployed (TRL9) and a near-term solution for hydrogen transport by road, albeit best suited for modest distances and scale.

10.3.3 Hydrogen production: Alkaline water electrolysis is the oldest and most established electrolyzer technology (TRL9). Moreover, proton exchange membrane (PEM) electrolyzers better suited for flexible operation are in the market at TRL 9, with policy support in Europe now focused on scaling up production and driving down costs. Finally, solid oxide electrolyzer cells (SOEC) – that can achieve higher electrical efficiency by utilizing heat – are in the demonstration phase, roughly at TRL7-8.

10.3.4 Hydrogen consumption: Proton exchange membrane (PEM) fuel cells are already commercially deployed in multiple applications (TRL9), though further commercialization (wider adoption) will depend on cost breakthroughs, fueling infrastructure, and durability enhancements. Solid oxide fuel cells (SOFC) are from a technology readiness standpoint already at full maturity (TRL 9). The key hurdles are economic rather than technical for wider deployment. Hydrogen-fueled turbines are in the demonstration/pilot stage (roughly TRL 7). A few pilot projects have validated the concept at moderate scale, but further development and larger field demos are needed before this becomes a commercial (TRL 9) option for power generation. Please note that "hydrogen-ready" gas turbines at TRL9 are essentially conventional natural-gas turbines with design modifications that allow them to operate flexibly using blends of hydrogen and natural gas, usually up to 20 to 30 percent hydrogen initially, sometimes up to 50 percent.

10.4 Nuclear reactor technology

Small and large light-water nuclear reactor technologies have operated for over half a century, consisting mostly of light-water reactors (LWRs) such as pressurized water reactors (PWRs) and boiling water reactors (BWRs). In addition, there have also been a significant deployment of pressurized heavy water reactors (PHWRs).

Recently, there has been a significant interest in small modular reactor (SMR) deployment, with a hundred different designs participating in the race toward commercialization (Nøland *et al.*, 2024c). Some SMR concepts are based on more well-established technologies (TRL7-9) while others focus on next-generation reactor design concepts with technological maturity as low as TRL2-3. A critical assessment of these technologies is needed to understand the technical risks associated with future deployments of nuclear energy. Table 14 list the five SMRs that are currently operating.

Table 14. List of the five operational SMRs deployed worldwide.

Number of units	Model	Reactor	Electrical capacity	Thermal capacity	Supplier	Location
2	KLT-40S	PWR	35 MW	150 MW	Rosatom	Akademik Lomonosov, Russia
2	HTR-PM	HTGR	210 MW	500 MW	INET	Shidaowan, Shandong, China
1	IPHWR-220	PHWR	220 MW	700 MW	NPCIL	Kaiga Atomic Power Station, India

10.4.1 Conventional small modular reactors (SMRs): As of 2025, no SMRs has reached full commercial operation (TRL 9) in the West, though a few first-of-a-kind projects are in progress. Ontario Power Generation (OPG) has officially made the investment decision to build four GE-Hitachi BWRX-300 SMRs at the Darlington nuclear site in Ontario, Canada, with the first unit expected to be operational by 2030. First EU deployments expected in early 2030s and benefits from existing supply chains of existing nuclear reactors based on light-water and heavy-water technologies. They lack economics of scale with respect to large conventional reactors but are expected to reduce risks of cost and time overruns, lower construction time, and improve learning rates due to economics of mass production. There have been an ongoing debate in the existing literature on the future costs of SMR technologies (Hjelmeland and Nøland, 2024). In the 2024-edition of the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB), future cost projections for 300-MW SMRs were presented for the first time (NREL, 2024c), as depicted in Figure 27.

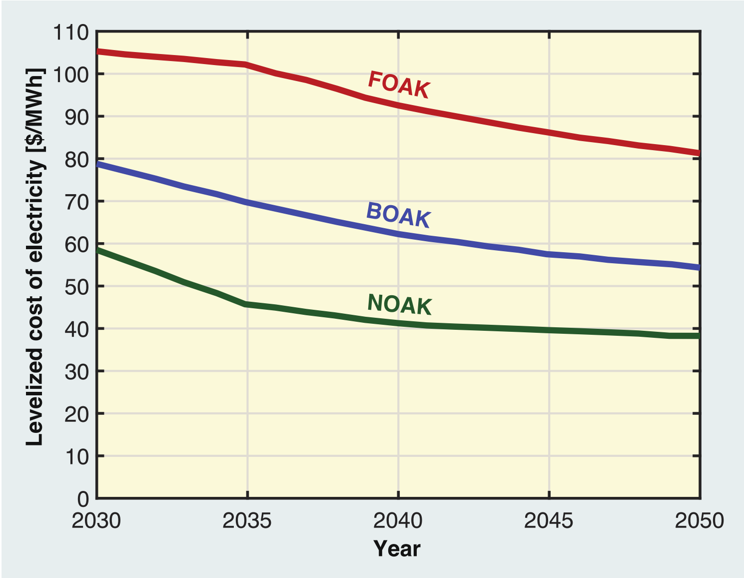

Figure 27. FOAK, NOAK, and BOAK cost projections with 60-year capital recovery for 300-MW small modular reactors based on the technology-neutral market-based scenario of the National Renewable Energy Laboratory's ATB (NREL, 2024c). FOAK: first of a kind; NOAK: Nth of a kind; BOAK: between FOAK and NOAK; ATB: Annual Technology Baseline.

10.4.2 Next-generation advanced modular reactors (AMRs): The highest demonstrated TRL for this category is the Chinese high-temperature gas-cooled pebble-bed reactor (NuclearNewswire, 2024), which is currently under operation (TRL8). For molten-salt reactors, currently at TRL3-5, a small 2 MW_{th} test in China began operation in 2021–2022, and a 10 MW_e thorium demo is planned by the end of this decade. Liquid metal-cooled reactors includes China's CFR-600 (600 MW_e) fast reactor, which started up in 2023. Moreover, a US demo (TerraPower's 345 MWe Natrium, sodium-cooled) is slated by 2030. Thus, sodium FR tech is near-demonstration/commercial (TRL7–8). The less advanced 300 MW_e BREST-OD-300 lead fast reactor in Russia has recently begun pilot operation.

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List of Figures

Figure 1. Illustration of the SCBOE cost components covering the full system cost of a variable renewable energy (VRE) resource. 6

Figure 2. Dinner plate model of the technology mix for a robust and balanced electricity system. 7

Figure 3 Dinner plate model of technology mix for a robust and balanced electricity system. 10

Figure 4 Illustration of the different cost categories covering the full system-level cost in the SCBOE framework. (a) VRE inverter-based resources. (b) Firm, plannable synchronous resources. 19

Figure 5 Stylized example of profile-adjusted VRE LCOE assuming a 85% use rate and a 70% value factor........ 28

Figure 6 Normalized value factor and use rate-adjusted LCOE for VRE resources. The value factor refers to the ratio between the capture price and the wholesale electricity price, while the use rate takes into account curtailed generation or reduced energy resources leading to a lower capacity factor........ 28

Figure 7 Stylized example of profile-adjusted nuclear LCOE with 50% a capacity factor assuming curtailment at near-zero market price with a 200% value factor for the remaining power. Unadjusted LCOE assumes a 90% capacity factor. 29

Figure 8 The R3 concept visualized through Venn diagram. 39

Figure 9 Relationship between reliability and resilience........ 40

Figure 10. Resilience as a process. 42

Figure 11. Intraday market re-trading volume for EPEX SPOT and Nord Pool between 2009 and 2024. 48

Figure 12. Intraday market-adjusted LCOE for VRE resources as a function of ID selling price due to VRE surplus price cannibalization and re-trading volumes, assuming equal amounts of over- and under-production and zero average price premium between ID and DA markets. 49

Figure 13. Stylized balancing power market response dynamic after a disturbance, highlighting different products. 50

Figure 14. Balancing market adjusted LCOE for different dimensioned VRE forecast errors with an average balancing price relative to the day-ahead price, both accounting for capacity reservation and energy activation. 51

Figure 15. Rise in the annual system costs for operating the Norwegian power system (NVE-RME, 2024) (NVE, 2025), indicating shares of primary reserves (FCR), secondary reserves (aFRR), and tertiary reserves (mFRR). Assumed currency exchange rate is 10.5 NOK/$........ 53

Figure 16. Average ratio of upward and downward frequency restoration reserves (aFRR and mFRR combined) to the total variable renewable energy (VRE) generation from solar and wind in Germany from 2008 to 2024. For more information, see (Koch and Hirth, 2019) (Agora Energiewende, 2025),........ 54

Figure 17. Non-frequency ancillary services used by transmission and distribution system operators (Glowacki Law Firm, 2024). 56

Figure 18 Overview of IBRs and non-IBRs in a fossil-free power grid. Note that, to be consistent with fossil-free generation, fuel cells and hydrogen turbines can only be fueled by non-fossil hydrogen. 58

Figure 19 Estimated levelized cost of operation (LCOO) of SynCons paired with inverter-based resources as a function of capacity factor. Three different SynCon cost levels are plotted, depending on more expensive new builds or if SynCon components are installed in existing machines. Calculations assume a 5% interest rate, 30-year capital recovery time, 3% power losses relative to kVA-rating, and 2% annual operation and maintenance costs relative to initial capital expenditure........ 59

Figure 20. Levelized cost of transmission (LCOT) for different grid connection cost levels and capacity factors, assuming a 30-year capital recovery time and a 5% interest rate, while neglecting operation and maintenance (O&M) costs. 63

Figure 21. Solar PV and wind (onshore + offshore) share in covering the electricity demand on the European Union level in 2024, source: EnergyCharts.de 70

Figure 22. Extreme week with very low solar PV and wind (onshore + offshore) generation on the EU level, source: EnergyCharts.de. Although the load is about 5 % above the 2024 average, wind generation is down by 42 % and solar PV by 37 % compared to their annual averages. 70

Figure 23 A Saharan dust storm halved solar generation in Spain over the period of almost two weeks in 2022. Data source: energycharts.de 72

Figure 24. Lake Mead storage state of filling over the last decades. 75

Figure 25. Critical elements price variability over the years 2018-2024 (Daily Metal Prices, 2024)...81

Figure 26. FOAK, NOAK, and BOAK cost projections with 60-year capital recovery for 300-MW small modular reactors based on the technology-neutral market-based scenario of the National Renewable Energy Laboratory's ATB (NREL, 2024c). FOAK: first of a kind; NOAK: Nth of a kind; BOAK: between FOAK and NOAK; ATB: Annual Technology Baseline. 95

List of Tables

Table 1. Key evaluation dimensions and indicators for assessing future power system scenarios. .. 8

Table 2. Comparison of different metrics to account for the cost of electricity of solar, wind, nuclear, and biomass. 17

Table 3. Description of different terms used when assessing the full system cost. 20

Table 4. Overview of the full system-level costs (OECD & NEA, 2021) (OECD, 2022), including the social costs of electricity generation technologies (Samadi, 2017). 23

Table 5. Stylized example of full system costs covering all cost elements using the described basic assumptions. 25

Table 6. Key evaluation dimensions and indicators for assessing future power system scenarios. 32

Table 7. Overview of different terms used. 41

Table 8. Different power market definitions. 47

Table 9. Case study of reserve products cost and supply in Sweden's 2024 balancing power market (Svenska Kraftnät, 2024). Assumed currency exchange rate is 11 SEK/ $. 51

Table 10. Provision of essential ancillary services from synchronous and inverter-based resources. 57

Table 11. Clean energy transition risk assessment as per International Energy Agency, source: (IEA, 2024c). 81

Table 12. Energy payback time for selected technologies, adopted from source EPT (IPCC, 2011): 84

Table 13. Life cycle emissions per kWh of electricity generated from different source, based on (IPCC, 2018). 85

Table 14. List of the five operational SMRs deployed worldwide. 94

Abbreviations

Abbreviation	Meaning
aFRR	Automatic Frequency Restoration Reserve
AMR	Advanced Modular Reactors
ATB	Annual Technology Baseline
AVR	Automatic Voltage Regulator
BOAK	Between FOAK and NOAK
BP	Balancing power
BRP	Balancing Responsible Party
BWR	Boiling water reactors
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CSP	Concentrated solar power
DA	Day-ahead
DC	Data centers
DOE	U.S. Department of Energy
FCR	Frequency Containment Reserves
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capacity
EPBT	Energy Payback Time
EROEI	Energy Return on Energy Invested
EROI	Energy Return on Investment
ERMA	European Raw Materials Alliance
ESS	Energy storage system
FERC	Federal Energy Regulatory Commission
FFR	Fast frequency reserve

FOAK	First-of-a-kind
GFL	Grid-following
GFM	Grid-forming
HDI	Human Development Index
HILP	High-impact, low-probability
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IBR	Inverter-based resources
ID	Intraday
IEA	International Energy Agency
IMF	International Monetary Fund
IRR	Internal rate of return
JRC	Joint Research Centre
kvA	Kilovolt-ampere
kW	Kilowatt
LACE	Levelized avoided cost of electricity
LCA	Lifecycle assessment
LCOE	Levelized cost of electricity
LCOO	Levelized cost of operation
LOLE	Loss of load expectation
LCOT	Levelized cost of transmission
LFP	Lithium iron phosphate
LFSCOE	Levelized full system costs of electricity
LMC	Locational marginal costs
LWR	Light-water reactors
mFRR	Manual frequency restoration reserve
MW	Megawatt
MWh	Megawatt-hour

NIMBY	Not in my backyard
NOAK	Nth-of-a-kind
NREL	National Renewable Energy Laboratory
NPV	Net present value
OPEX	Operational expenditure
PHS	Pumped storage hydropower
PHWR	Pressurized heavy water reactors
PM	Particulate matter
PSH	Pumped storage hydropower
PSS	Power system stabilisers
PV	Photovoltaic
PWR	Pressurized water reactors
REE	Rare earth elements
SAIDI	System average interruption duration index
SCBOE	System cost breakdown of electricity
SCC	Social Cost of Carbon
SCL	Short circuit level
SCOE	The social cost of electricity
SMR	Small modular reactor
SynCons	Synchronous condensers
TRL	Technology readiness level
TSO	Transmission system operator
VALCOE	The value-adjusted LCOE
VRE	Variable renewable energy
WACC	Weighted average cost of capital

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