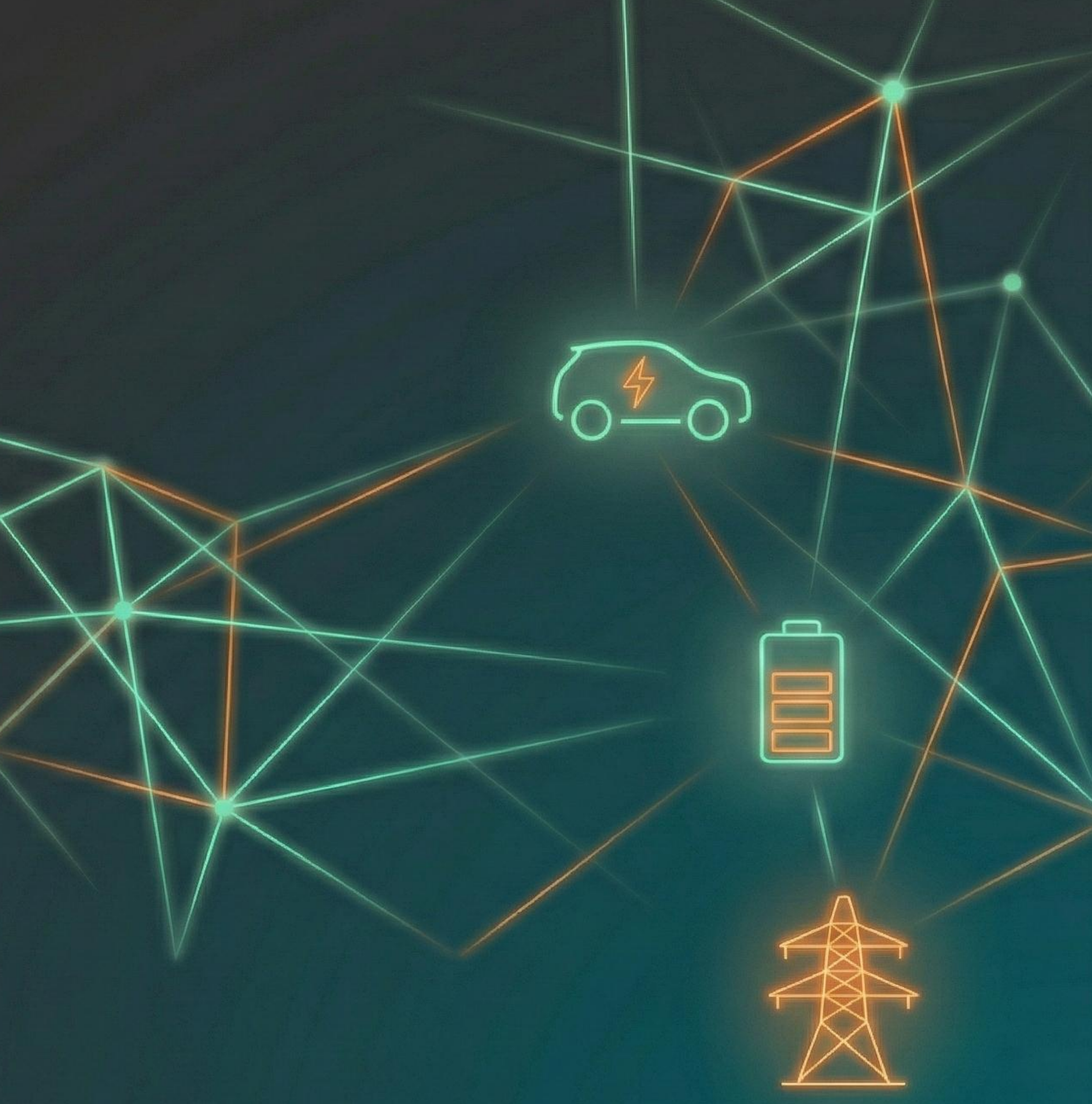
Flexible Futures:

Scenario Analysis of Electric Vehicles, Batteries, and the Belgian Electricity System



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1. Executive Summary

The transition toward an electricity system dominated by variable renewable energy sources creates fundamental challenges in matching supply with demand across multiple timescales. Electric vehicles and stationary batteries represent two promising flexibility resources capable of absorbing renewable surpluses and discharging during demand peaks, yet their interaction with each other and with the broader electricity system remains insufficiently understood. This report examines these dynamics through detailed hourly dispatch simulations of the Belgian electricity system and its European neighbours, revealing findings with significant implications for policymakers, investors, and system planners.

Methodology and Scenario Framework

The analysis employs a European electricity market model that optimises hourly dispatch across the interconnected European system, capturing the cross-border flows that fundamentally shape Belgian market outcomes. The modelling framework builds upon the ENTSO-E TYNDP 2024 National Trends scenarios, which provide harmonised assumptions regarding generation capacity, demand evolution, and network infrastructure for 2030 and 2040.

Six distinct scenario variants were constructed by systematically varying two key dimensions. The first dimension concerns stationary battery deployment: LOW BAT scenarios assume modest battery capacity with short duration, whilst HIGH BAT scenarios assume substantially larger fleets with longer duration. Both represent deliberate deviations from the TYNDP National Trends assumptions, in opposite directions, to explore how battery deployment scale affects system dynamics. The second dimension concerns electric vehicle charging behaviour: DUMB scenarios assume uncontrolled charging following driver convenience; SMART scenarios optimise charging timing without bidirectional capability; and V2G scenarios enable vehicles to discharge back to the grid during high-price periods.

These scenarios are deliberately constructed as polar cases rather than probabilistic forecasts. The HIGH BAT assumptions represent battery capacities that may not materialise at such scale in the 2030/2040 timeframe and universal V2G adoption represents an upper bound on what flexibility could theoretically deliver. The value of this approach lies in revealing mechanisms, sensitivities, and trade-offs that will shape system evolution, rather than predicting specific outcomes.

Key Findings

The analysis reveals that flexibility deployment does not benefit all market participants equally. Consumers emerge as clear beneficiaries, experiencing compressed price distributions that reduce both average electricity costs and exposure to extreme price spikes. The near-elimination of scarcity pricing events in flexibility-rich scenarios translates directly into lower and more predictable electricity bills.

For stationary battery operators, the findings are more sobering. Battery profitability erodes substantially as deployment increases, with per-gigawatt surplus declining by up to 86 percent between the most favourable scenario (LOW BAT DUMB) and the least favourable (HIGH BAT V2G). The mechanism is price compression: batteries earn revenues by exploiting the spread between low-price and high-price periods, but **their collective operation compresses the very spreads they exploit. When V2G-capable electric vehicles perform similar arbitrage functions, they further compress available spreads**, **leaving even less value for stationary batteries to capture**. **Long-duration batteries face particularly challenging economics**; even at aggressive cost assumptions for 2030 and 2040, wholesale arbitrage revenues are grossly insufficient to recover capital costs.

Gas-fired generation faces what might be understood as a second wave of economic pressure. The first wave arrived in the 2010s, when renewable deployment and the merit order effect eroded CCGT operating hours, prompting capacity remuneration mechanisms across Europe. Now a second mechanism emerges: **flexibility resources eliminate the scarcity pricing events during which CCGTs earn their highest remaining margins. Per-gigawatt surplus falls by 50 to 80 percent across the scenario range**. The plants remain essential for system adequacy during prolonged periods of low renewable output, but the high-value operating hours that once compensated for low utilisation are progressively claimed by competing flexibility resources.

Nuclear power presents a notable paradox. **Flexibility deployment enables higher nuclear capacity factors** by absorbing renewable surpluses that would otherwise pressure plants to reduce output. Belgian nuclear capacity factors rise from 72 percent (LOW BAT DUMB) to 78 percent (HIGH BAT V2G) in 2030. **However, the same price compression that benefits consumers reduces the value of each megawatt-hour produced**. **Higher output coincides with lower revenues per unit**, leaving nuclear operators operationally better off but economically challenged, with per-gigawatt surplus declining by 31 percent across scenarios.

Among flexibility options, **unidirectional smart charging stands out as a clear priority**. Smart charging requires minimal additional hardware, imposes no additional degradation on vehicle batteries, and faces fewer consumer acceptance barriers than bidirectional alternatives. Yet it delivers substantial system benefits by shifting EV charging to periods of high renewable generation, absorbing surpluses that might otherwise be curtailed. Unlike battery cycling, which incurs round-trip efficiency losses of approximately 8 to 9 percent, smart charging that merely shifts demand timing triggers no such losses. **Vehicle-to-grid capability adds further potential, but its value proves conditional: in scenarios with abundant stationary batteries, V2G utilisation declines by 65 to 72 percent** as batteries absorb the arbitrage opportunities that V2G would otherwise capture.

Belgium's position as a small, highly interconnected country shapes how domestic flexibility resources create and capture value. Large neighbouring countries dominate regional price formation, with renewable and battery capacities measured in hundreds of gigawatts. **Belgian flexibility resources operate within a price environment substantially determined by conditions in other countries**. This international embedding means that **domestic investments interact with neighbour decisions** in ways that affect outcomes for all parties.

Flexibility deployment generates meaningful environmental co-benefits alongside economic effects. CO_2 emissions intensity declines by 12 to 21 percent in flexibility-rich scenarios compared to inflexible baselines, achieved purely through more intelligent use of existing resources without additional generation investment. For Belgium, with its substantial reliance on gas-fired generation for balancing, the climate case for flexibility deployment is particularly strong.

Conclusions and Implications

The analysis reveals an electricity system in transition, where familiar assumptions about generation economics and market dynamics are being reshaped by flexible demand and distributed storage. The competitive relationship between EV flexibility and stationary batteries, the erosion of conventional generator revenues, and the international interdependencies shaping domestic outcomes all represent dynamics that will intensify as the energy transition proceeds.

For policymakers, the clearest priority is enabling smart charging infrastructure and market arrangements. The benefits are substantial, costs are modest, and consumer acceptance barriers are lower than for bidirectional alternatives. **Regarding stationary batteries and EV flexibility, the findings suggest caution about simultaneously pushing hard on both fronts**; they compete for overlapping value pools, and aggressive support for both could result in expensive underutilised infrastructure.

For investors, the central message concerns uncertainty and conditionality. Flexibility economics depend on the broader flexibility landscape, which cannot be predicted with confidence. Business cases should be stress-tested against scenarios where competing flexibility is both scarce and abundant. Duration matters: shorter-duration batteries face better arbitrage economics than longer-duration systems. Value stacking across multiple revenue streams may prove essential rather than optional, as wholesale arbitrage alone appears insufficient to recover capital costs in flexibility-rich futures.

The overall picture is not one of crisis or failure. The simulated systems function across all scenario variants; supply meets demand, prices form sensibly, and the transition toward lower-carbon electricity proceeds. The question is not whether flexibility can work, but how its costs and benefits will be distributed, which investment strategies will prove sound, and how policy can best facilitate efficient outcomes.

2. Introduction

The European electricity system is undergoing a profound transformation as it advances towards decarbonisation targets for 2030 and 2040. This transition represents a fundamental paradigm shift in power system operations: from traditional "load-following generation," where dispatchable power plants adjust output to meet demand, to "generation-following load," where demand must increasingly adapt to variable renewable supply. In high-renewable systems, the most relevant metric is no longer gross electricity demand but rather "residual load" (demand minus variable renewable generation), which creates entirely new flexibility requirements that conventional 20th century system designs were not built to accommodate.

Central to this transition is the electrification of transport and the deployment of energy storage technologies. The electrification of transport creates a unique "double opportunity": electric vehicles represent both a significant new load that could stress the grid and a potential flexibility resource that could help integrate variable renewables. The outcome depends critically on charging behaviour and market design to provide the right incentives. Previous studies have demonstrated that the value of demand-side flexibility scales dramatically with renewable penetration: at moderate renewable shares, flexibility benefits are modest; at high shares exceeding 50-60% variable renewables, flexibility becomes essential for system viability and cost-effectiveness. **Understanding how these resources interact with the broader electricity system, and with each other, is therefore essential for effective policy design, infrastructure planning, and market development**.

Belgium occupies a particularly interesting position in this transition. The country's unique company car taxation system has catalysed one of Europe's most rapid shifts towards electric mobility. Belgian fiscal policy allows employers to provide company cars as part of employee remuneration packages, with all kilometres driven (including private use) covered by the employer. Due to these incentives, **the Belgian car fleet is electrifying at an accelerated pace**, creating both a unique opportunity and a pressing need to understand the system-level implications.

Simultaneously, **Belgium is witnessing a surge in stationary battery storage development**. Major energy companies are advancing ambitious projects: ENGIE is constructing a 200 MW battery park in Vilvoorde with 800 MWh of storage capacity, one of the largest such facilities in Europe, expected to be fully operational by January 2026. Meanwhile, several *gigawatts* of additional battery capacity are in various stages of planning and permitting, though final investment decisions have not yet been taken for all proposed developments. The extent to which this pipeline materialises will significantly influence Belgium's electricity system flexibility in the coming decade.

Belgium's electricity system in 2030-2040 will face a particular challenge: a potential phase-out of existing nuclear capacity in the mid-2030s and the addition of new nuclear capacity in the 2040s – combined with ambitious renewable targets – creates a structural need for flexibility that must be met by some combination of imports, gas-fired generation, storage, and demand response. Moreover, **Belgium's position as a highly interconnected country in central Europe means its domestic flexibility resources do not operate in isolation**; they compete and interact with flexibility options across the broader European system, including French nuclear, German solar, Dutch gas, and British offshore wind through market coupling. Understanding these cross-border dynamics is essential for assessing the true value of Belgian flexibility resources.

The interaction between EV flexibility and stationary batteries is not straightforward: they can in principle be complements (serving different needs) or substitutes (e.g. by competing for the same arbitrage opportunities). Disentangling these effects requires systematic scenario analysis. The question of whether EVs and stationary batteries are complements or substitutes is not merely academic; it has direct implications for investment decisions, market design, and policy support. If they are primarily substitutes, supporting both aggressively may lead to underutilised assets and compressed returns; if they are complements, coordinated deployment could unlock synergies. Previous European-wide modelling studies have found that flexible EV charging can reduce stationary battery investment needs by 60-90% in cost-optimised systems. However, these findings depend on assumptions about EV availability, user behaviour, and the sophistication of control systems that may not hold universally. Moreover, since the electricity system is not centrally cost-optimised in practice as it is in some modelling studies, it is possible that large fleets of flexible EVs coincide with large stationary battery capacities in the real world, making it important to understand how these resources interact operationally when both are present.

The value of flexibility is inherently context-dependent. A flexible EV in a system with abundant hydropower flexibility (such as Norway) provides less incremental value than the same EV in a system with a significant share of inflexible nuclear and limited storage capacity (such as Belgium). This geographic specificity motivates analyses focusing on the context of a particular country, whilst also examining cross-country patterns to understand what drives these differences. These parallel developments (a rapidly electrifying vehicle fleet driven by fiscal policy and a substantial pipeline of grid-scale battery storage) make Belgium an ideal case study for examining the system-level impacts of flexibility resources. How will millions of electric vehicles, charging at home and at work, affect demand patterns and peak loads? What role can smart charging and vehicle-to-grid technology play in integrating variable renewable energy? How do stationary batteries interact with EV flexibility, and to what extent are they complementary or substitutes? What are the implications for gas-fired generation economics, electricity prices, and carbon emissions? These questions have direct relevance for transmission system operators, policymakers, and investors across Europe.

In this report, these questions are addressed as part of Task 1.3 of the InterFlex project. Using Artelys Crystal Super Grid (ACSG), a state-of-the-art electricity system optimisation platform that underpins the European Commission's METIS model suite, we conduct detailed hourly dispatch simulations for 2030 and 2040. Our analysis builds upon the ENTSO-E Ten-Year Network Development Plan (TYNDP) 2024 National Trends scenarios, constructing a structured matrix of scenario variants to examine the impacts of different EV charging behaviours (uncontrolled, smart, and vehicle-to-grid) and stationary battery deployment levels (low versus high capacity assumptions). By simulating the full European interconnected system rather than Belgium in isolation, we capture the cross-border effects that are essential for understanding flexibility value in a highly connected electricity market.

The report is structured as follows. Section 3 describes the methodology, including an overview of the TYNDP scenarios, the ACSG modelling framework, the representation of electric vehicles and stationary batteries, and the scenario structure adopted for this study. Section 4 presents the simulation results, examining production and consumption patterns of EVs and batteries, dispatch dynamics, national electricity balances, peak demand contributions, the economics of nuclear and gas-fired generation, flexibility provision across different timescales, environmental outcomes, and electricity price dynamics. Section 5 concludes by synthesising the key findings and discussing their implications for flexibility planning in the European electricity system.

3. Methodology

3.1. Methodological Overview

This section provides a high-level overview of the methodological approach adopted in this study. The subsequent sections elaborate on each component in greater detail.

The central objective of this report is to investigate the influence of electric vehicles and stationary batteries on the future Belgian electricity system, taking into account the international context. To this end, we conduct hourly dispatch simulations for the years 2030 and 2040, systematically varying the assumed capacities and operational characteristics of these flexibility resources. The simulations are performed at hourly resolution across a full year (8,760 hours), which is essential for capturing the temporal dynamics of flexibility resources. Studies using reduced temporal resolution or “representative periods” often miss critical interactions during extreme weather events, seasonal variations, or peak demand periods that are crucial for understanding flexibility value.

Our analysis builds upon the ENTSO-E Ten-Year Network Development Plan (TYNDP) 2024 scenarios, which represent the most comprehensive and up-to-date projections of European electricity system development currently available. These scenarios provide a robust foundation in terms of installed generation capacities, demand profiles, and interconnection assumptions across all European countries. Future scenarios of the European electricity system are inherently complex, incorporating countless assumptions regarding generation technologies, fuel prices, demand evolution, network infrastructure, and policy developments. To obtain meaningful insights into specific questions such as the effect of EVs and stationary batteries, one must necessarily select a baseline and hold other variables constant, varying only the dimensions of interest and then comparing the resulting simulation outputs. Whilst no baseline choice is perfect, the TYNDP National Trends scenarios represent a logical, defensible, and reasonably neutral foundation for the purposes of this report.

Starting from this established baseline, we construct a structured matrix of scenario variants by introducing deliberate variations in two key dimensions: stationary battery capacity (low versus high deployment levels) and electric vehicle charging behaviour (ranging from uncontrolled charging through smart charging to full vehicle-to-grid capability). Our approach is to simulate "extreme" scenarios:

- *All* vehicles charging without coordination (also called “dumb” charging),
- versus *all* vehicles with smart charging,
- versus *all* vehicles with smart charging *and* V2G capability,
- combined with either *low* battery deployment or *high* battery deployment.

This approach follows established practice in energy system analysis. Bracketing uncertainty through **polar cases** often provides more policy-relevant insights than attempting to predict the most likely outcome, as it reveals the sensitivity of system outcomes to key uncertainties and identifies which variables matter most for decision-making. The use of a consistent baseline across all scenario variants ensures that observed differences in outcomes can be attributed to the specific changes we introduce (EV behaviour, battery capacity) rather than to confounding differences in other assumptions.

All scenario variants are simulated using ACSG (Artelys Crystal Super Grid), an advanced electricity system optimisation model that performs hourly dispatch across the full European interconnected system. **By simulating the complete European system rather than Belgium in isolation, we capture important cross-border effects**: Belgium's flexibility resources interact with French nuclear generation, German solar and wind output, Dutch gas-fired plants, and British offshore wind through market coupling. A purely national model would miss these dynamics, which are essential for understanding flexibility value in a highly interconnected market.

The methodology deliberately avoids endogenous capacity expansion for generation assets. This design choice allows us to **isolate the operational effects of flexibility deployment without confounding them with investment feedback effects** that would occur in a full capacity planning model. Our goal is not to identify "cost-optimal levels" of EV flexibility or stationary battery deployment. Given the real-world absence of a central planner optimally coordinating all energy system investments , we are primarily interested in the operational interaction effects, characteristics, and dynamics that emerge when these resources coexist at varying levels.

It is important to emphasise that **our analysis and its results are not intended as predictions**, let alone precise forecasts of future system states. They should instead be interpreted as indicating the direction and approximate magnitude of effects. **The primary motivation is to gain insight into the overall dynamics that policymakers, practitioners, and investors should be aware of at a high level**, enabling them to anticipate how the electricity system is likely to evolve as flexibility resources are deployed in the coming years. **The value lies not in predicting exact outcomes, but in understanding the mechanisms and relationships that will shape future system behaviour**.

The following sections describe the underlying TYNDP scenarios (Section 3.2), the ACSG modelling framework (Section 3.3), our scenario structure (Section 3.4), and the key exogenous inputs to the simulations (Section 3.5).

3.2. Role of the ENTSO-E TYNDP Scenarios

The scenarios underpinning our analysis are derived from the European Network of Transmission System Operators for Electricity (ENTSO-E) Ten-Year Network Development Plan (TYNDP) 2024. The TYNDP represents the most comprehensive and authoritative framework for projecting European electricity system development, drawing upon coordinated inputs from transmission system operators across all European countries. Within the TYNDP framework, multiple scenario families are defined to capture different possible futures; for this study, we focus specifically on the National Trends scenarios for the target years 2030 and 2040.

The National Trends scenarios represent a **"current policy trajectory,"** built bottom-up from Member State projections and reflecting what countries expect to achieve given current legislation and announced policy intentions. This scenario family is constructed by aggregating the national energy and climate plans (NECPs) submitted by EU Member States, along with equivalent planning documents from non-EU European countries. The resulting projections represent a coherent vision of European electricity system development that is grounded in official government positions rather than theoretical optimisation or normative targets.

Figure 1: TYNDP 2024 reports - 2024.entsos-tyndp-scenarios.eu

The philosophy behind the National Trends scenarios positions them as a "central" trajectory: neither the most ambitious decarbonisation pathway nor the most conservative projection. By anchoring our analysis in this middle-ground scenario, we seek to avoid the risk of basing conclusions on either overly optimistic or overly pessimistic assumptions about the pace of the energy transition.

It should be noted, however, that the National Trends scenarios still reflect a considerable degree of ambition, as they incorporate the national targets announced by governments rather than conservative estimates of what will actually be achieved. For example, the scenarios assume offshore wind expansions of tens of gigawatts in the Netherlands and the United Kingdom by 2030, deployments that may not entirely materialise in practice due to political uncertainty, supply chain constraints, permitting delays, and other factors. Readers should therefore interpret the scenario assumptions as representing policy aspirations rather than guaranteed outcomes.

The TYNDP scenarios encompass a vast array of assumptions extending far beyond installed generation capacities. These include projections of **fuel prices** (natural gas, coal, oil), **carbon prices** under the EU Emissions Trading System, **technical parameters** of generation technologies (such as thermal efficiencies of gas-fired plants, minimum stable generation levels, and ramp rates), assumptions regarding the **transmission network** (interconnection capacities, network topology, and planned reinforcements), and **demand projections** accounting for electrification trends across sectors. For complete details on all underlying assumptions, we refer readers to the extensive documentation published by ENTSO-E alongside the TYNDP 2024 release.

It is worth noting that the **TYNDP scenarios are designed primarily for network planning purposes**, specifically to identify transmission infrastructure investments needed to accommodate projected generation and demand patterns. As such, **they do not deeply explore the sensitivity of system outcomes to different configurations of flexibility resources**. The scenarios include assumptions about electric vehicle numbers and stationary battery capacities, but they do not systematically examine how different EV charging behaviours (uncontrolled versus smart versus V2G) or different battery deployment levels would alter system outcomes.

Similarly, Belgium's most policy-relevant national study in this domain, **Elia's biennial Adequacy and Flexibility Study**, provides valuable analysis of flexibility needs and adequacy requirements but does not conduct the systematic scenario matrix exploration undertaken in the present report. The Adequacy and Flexibility Study **focuses on identifying whether Belgium will have sufficient resources to meet demand under various conditions, rather than examining how different combinations of flexibility resources interact and compete**.

Our study fills this analytical gap by using the TYNDP National Trends scenarios as a robust baseline whilst introducing deliberate variations in the specific dimensions most relevant for understanding flexibility dynamics: EV charging behaviour and stationary battery deployment levels. This approach enables us to isolate and quantify effects that neither the TYNDP scenarios nor national adequacy studies are designed to capture, whilst remaining anchored in a credible and widely-accepted vision of European electricity system development.

3.3. Dispatch Modelling Framework

3.3.1. Overview of Artelys Crystal Super Grid

Artelys Crystal Super Grid (ACSG) is a state-of-the-art, web-based multi-energy capacity expansion and dispatch platform used for planning and policy analysis across interconnected energy systems. The platform is capable of representing electricity, gas, hydrogen, and heat systems, and co-optimises investment decisions and hourly operations within a unified framework. ACSG underpins the European Commission's METIS model suite, providing it with established policy-grade provenance and extensive documentation of model formulations and parameters.

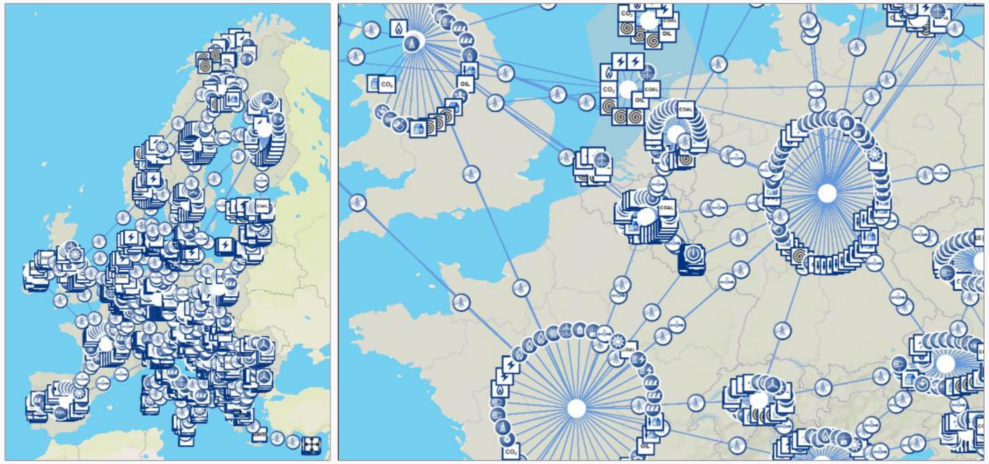


Figure 2: Model representation of the European electricity system in Artelys Crystal Super Grid

For the purposes of this study, we employ ACSG in dispatch simulation mode, optimising hourly operations across the full European interconnected electricity system. The model performs chronological optimisation across all 8,760 hours of the year, respecting unit commitment constraints (minimum on/off times, start-up costs, ramping limits), reserve requirements, and cross-border transfer limits. This **simultaneous optimisation of dispatch decisions across all European countries captures the essential feature that flexibility resources in one country interact with those in neighbouring systems through market coupling**. A purely national model would miss these cross-border dynamics.

It is important to note that the model assumes perfect foresight and cost-minimising dispatch, meaning it represents an idealised upper bound on achievable flexibility value. In practice, imperfect forecasts, transaction costs, market imperfections, and behavioural constraints will reduce the benefits that can actually be realised. The results should therefore be interpreted as indicating what is achievable under optimal coordination, recognising that real-world outcomes will fall short of this benchmark.

3.3.2. Price and Revenue Outputs

A useful feature of dispatch simulation models such as ACSG is their ability to output **electricity price proxies alongside physical dispatch results**. At each hourly timestep, the model identifies the marginal generation unit (the most expensive unit that is dispatched to meet demand). Since the model contains complete information on fuel prices, thermal efficiencies, and carbon prices, it can calculate the marginal production cost of electricity at each node and timestep. This **marginal cost** serves **as a proxy for the wholesale electricity price**.

It is important to emphasise that these simulations are not intended as electricity price forecasting tools; that is not their primary purpose. Nevertheless, the price outputs provide useful rough indications of the price dynamics that may emerge under different scenarios, the approximate magnitude of price levels, and how these differ across scenario variants.

These price outputs also enable the calculation of revenues and operating surpluses for generation assets within the simulation. Each MWh produced is sold at the price prevailing in that node at that hour. Since operational costs are fully specified in the model, **both total revenues** (income from electricity sales) **and operating surplus** (revenues minus variable costs) **can be computed for any generation technology**, such as nuclear plants or combined-cycle gas turbines (CCGTs). **This capability allows us to examine the "economics" of different generation technologies across scenarios**, as we do in the results section. Similar calculations can be performed for stationary batteries, accounting for both charging costs and discharge revenues.

3.3.3. Representation of Electric Vehicles

Electric vehicles are represented in ACSG as flexible demand assets that consume electricity (and, in the case of V2G, can also inject electricity back into the grid) according to specified availability patterns and constraints. Vehicles are not modelled individually; instead, the model works with aggregated fleets characterised by arrival and departure patterns that determine when vehicles are connected to charging infrastructure.

For each country (node), ACSG distinguishes six EV asset categories based on two dimensions:

- Charging location: “Home” or “Work”
- Charging behaviour:
  - Immediate (uncontrolled, i.e. “dumb”),
  - Smart (optimised), or
  - Smart with V2G (bidirectional)

This structure allows the scenario variants to be implemented by allocating the national EV fleet across these categories. In the DUMB scenario, all vehicles are assigned to the "Immediate Charging" categories; in the SMART scenario, all vehicles use "Smart Charging"; and in the V2G scenario, all vehicles have "Smart Charging with V2G" capability. The allocation between home and work charging reflects assumptions about where charging activity occurs (approximately 70% home, 30% work based on the underlying data).

The representation of EVs as aggregated fleets with availability constraints based on driving patterns is consistent with state-of-the-art practice in energy system models. Individual vehicle heterogeneity is captured statistically through the fleet distribution rather than by explicitly modelling thousands of individual vehicles. **A critical constraint for EV flexibility is ensuring that vehicles are sufficiently charged for their next trip. This "mobility constraint" fundamentally limits how much flexibility can be extracted from the EV fleet and creates an asymmetry between charging flexibility** (which can be shifted in time) **and V2G discharge** (which reduces the energy available for driving). Studies using detailed trip data have shown that the naive assumption that all EV battery capacity is available for flexibility dramatically overestimates the actual flexibility potential, potentially by factors of 10 or more. Proper accounting for mobility constraints, as implemented in ACSG, is therefore essential for realistic flexibility assessment.

Table 1: EV parameters

Parameter	Value	Description
Average battery capacity	79 kWh	Usable storage capacity per vehicle
Average journey discharge	~15 kWh	Energy consumed per typical commute
Charging power	7.4 kW	Average charging rate per vehicle
Charging efficiency	94%	AC-to-battery efficiency
V2G discharge power	7.4 kW	Bidirectional power rating (V2G only)
V2G discharge efficiency	94%	Battery-to-grid efficiency

The arrival and departure patterns used in the model are specified as hourly time series across a representative week, reflecting typical commuting behaviours. Arrivals at home peak in the late afternoon and evening (17:00-20:00), whilst arrivals at work peak in the morning (07:00-09:00). These patterns determine when vehicles are connected and available for charging or V2G services.

For immediate (uncontrolled) charging, vehicles begin charging as soon as they arrive and are plugged in, continuing at full power until fully charged. This behaviour is exogenously determined by the arrival patterns and is not optimised by the model.

For smart charging, the timing of charging is optimised by the model subject to the constraint that vehicles must be fully charged before their scheduled departure. The model treats the connected EV fleet as an aggregated "battery pool," optimising when to draw power from the grid to minimise system costs whilst ensuring all departing vehicles have sufficient charge.

For smart charging with V2G, the model can additionally discharge energy from vehicle batteries back to the grid when this reduces system costs[1]. V2G is subject to the same departure constraints: all vehicles must still be fully charged when they disconnect. The model optimises the charging and discharging schedule to minimise total system costs, potentially discharging during high-price periods (e.g., evening peaks) and recharging during low-price periods (e.g., overnight or during solar peaks).

Table 2 Number of electric vehicles assumed for 2030 and 2040 (millions)

Country	2030	2040
BE	1.9	4.2
DE	15.5	38.1
FR	7.9	24.5
NL	2.3	6.3
UK	8.2	30.8

3.3.4. Representation of Stationary Batteries

Stationary batteries in the model represent aggregated lithium-ion battery storage capacity. For clarity, this encompasses all stationary battery applications: residential batteries (typically a few kilowatts and kilowatt-hours), medium-sized installations at commercial or industrial sites (tens to hundreds of kilowatts), and utility-scale battery parks (tens to hundreds of megawatts). The model does not distinguish between these segments; instead, all stationary battery capacity within a country is represented as a single aggregated storage asset with specified power rating (MW), energy capacity (MWh), and round-trip efficiency.

It should be noted that stationary batteries in reality can earn revenues from multiple value streams beyond wholesale energy arbitrage, including frequency containment reserves (FCR), automatic and manual frequency restoration reserves (aFRR/mFRR), imbalance market trading, and portfolio balancing services. However, **as gigawatts of flexible EVs, stationary batteries, and other assets enter the market to compete for these revenue streams, the shallower reserve markets are likely to saturate relatively quickly**. **Wholesale price arbitrage**, being "deeper" (i.e. less easily saturated due to the enormous volumes involved, which are European-scale due to market coupling), **will likely become the dominant revenue source for the growing storage fleet**. Our modelling captures this primary value stream. Additional revenues from ancillary services would improve battery economics at the margin, but the wholesale arbitrage dynamics that drive our results represent the most significant and scalable revenue opportunity.

The battery storage parameters (power capacity, energy capacity, and storage duration) are varied across scenarios as described in Section 3.4, with the LOW BAT and HIGH BAT variants representing substantially different assumptions about battery deployment levels.

[1] In this context, the expression "system costs" refers to the optimisation objective of the dispatch simulation. The "goal" of the model is to minimize the total operational cost associated with meeting hourly electricity demand in all nodes of the European network. EV smart charging and V2G are therefore optimized specifically with this goal in mind. This is a necessary simplification of real-world algorithms and behaviours associated with commercially deployed smart charging and V2G services.

3.4. Scenario Structure

To systematically examine the influence of electric vehicles and stationary batteries on the electricity system, we construct a matrix of scenario variants by varying two key dimensions: EV charging behaviour and stationary battery deployment levels. This creates **six distinct scenario variants for each target year (2030 and 2040), enabling structured comparison of outcomes across different flexibility configurations**.

3.4.1. Scenario Dimensions

Electric Vehicle Charging Behaviour (3 variants):

> **DUMB**: All electric vehicles charge immediately upon connecting to a charging point, without any coordination or optimisation. Charging begins as soon as the vehicle is plugged in and continues at full power until the battery is full. This represents a baseline scenario where no smart charging infrastructure or incentives exist.

> **SMART**: All electric vehicles employ smart charging, where the timing of charging is optimised to minimise system costs whilst ensuring vehicles are fully charged before their next departure. Vehicles can delay charging to periods of lower electricity prices or higher renewable availability, but cannot feed energy back to the grid.

> **V2G**: All electric vehicles employ smart charging with vehicle-to-grid capability. In addition to optimised charging timing, vehicles can discharge energy back to the grid when this reduces system costs. This represents the maximum theoretical flexibility potential of the EV fleet.

Stationary Battery Deployment (2 variants):

> **LOW BAT**: Battery power capacity is set to half of the values assumed in the ENTSO-E TYNDP National Trends scenarios, with a storage duration of 2 hours. For example, a country with 100 MW of battery power capacity in LOW BAT would have 200 MWh of energy storage capacity.

> **HIGH BAT**: Battery power capacity is set to double the TYNDP National Trends values, with a storage duration of 6 hours. The same country would have 400 MW of power capacity and 2,400 MWh of energy storage capacity. The combination of higher power ratings and longer duration means that HIGH BAT represents a 12-fold increase in total storage capacity compared to LOW BAT.

3.4.2. Scenario Matrix

The combination of three EV variants and two battery variants yields six scenarios per target year:

Table 3: Scenario Matrix

Scenario	EV Behaviour	Battery Level	Description
DUMB × LOW BAT	Uncontrolled	Low power capacity, 2h duration	Minimal flexibility from both sources
DUMB × HIGH BAT	Uncontrolled	High power capacity, 6h duration	Battery-dominated flexibility
SMART × LOW BAT	Optimised charging	Low power capacity, 2h duration	EV flexibility with limited batteries
SMART × HIGH BAT	Optimised charging	High power capacity, 6h duration	Both sources provide flexibility
V2G × LOW BAT	Optimised charging + discharging	Low power capacity, 2h duration	Maximum EV flexibility, limited batteries
V2G × HIGH BAT	Optimised charging + discharging	High power capacity, 6h duration	Maximum flexibility from both sources

3.4.3. Rationale: Examining the Extremes

The general philosophy underlying this scenario structure is to examine "extreme" or "polar" cases rather than attempting to predict the most likely outcome. By assuming that all EVs behave homogeneously (all uncontrolled, or all smart, or all V2G) and that battery deployment is either consistently low or consistently high, we deliberately bracket the range of possible futures. This approach follows established practice in energy system analysis, where exploring boundary conditions often provides more policy-relevant insights than probabilistic forecasting.

The assumption that all EVs behave identically is a deliberate simplification. In reality, adoption of smart charging will be gradual and uneven: some vehicle owners will participate in flexibility programmes whilst others will not; some charging locations will have smart infrastructure whilst others will not. Similarly, stationary battery deployment will likely fall somewhere between our LOW BAT and HIGH BAT assumptions, though technological evolution and cost reductions could push outcomes toward the higher end more rapidly than currently anticipated.

By examining the extremes, we reveal the sensitivity of system outcomes to these key uncertainties and identify which variables matter most for policy and investment decisions. The difference between DUMB and V2G scenarios indicates the maximum value that could be unlocked through EV flexibility; the difference between LOW BAT and HIGH BAT indicates the impact of battery deployment at different scales.

3.4.4. Interaction Effects and Saturation

The interaction between EV charging behaviour and battery deployment creates a two-dimensional space of possibilities with important non-linear characteristics. Previous modelling studies have found that **the marginal value of additional flexibility declines as more flexibility is added to the system**. **This suggests potential "saturation" effects that our scenario matrix is designed to reveal**.

In configurations with abundant flexibility from multiple sources (HIGH BAT combined with V2G charging), the system may have more flexibility than strictly needed to absorb renewable variability, potentially leaving some flexibility capacity underutilised. The value that each resource captures depends on what other resources are available: V2G may be highly valuable when batteries are scarce, but less valuable when large battery fleets are already providing similar services.

Conversely, configurations with limited flexibility (LOW BAT combined with DUMB charging) may experience higher renewable curtailment, greater price volatility, and increased reliance on gas-fired generation to manage variability. By comparing outcomes across all six scenarios, we can identify where threshold effects occur and where diminishing returns set in.

3.4.5. Important Caveats on Real-World Behaviour

Whilst the scenario structure provides analytical clarity, it is important to acknowledge significant simplifications relative to real-world conditions.

Electric vehicle charging in practice will not be perfectly optimised from a central system perspective, even when "smart" charging is enabled. In reality, smart charging may be deployed for diverse purposes: maximising self-consumption of rooftop solar, minimising peak demand charges (as is relevant under the Flemish capacity tariff), responding to time-of-use pricing, or simply user convenience. These objectives may sometimes align with system-optimal dispatch but will not always do so. The model's assumption of perfect coordination represents an upper bound on achievable value.

Stationary battery dispatch in practice will similarly deviate from the centralised cost-minimisation assumed in the model. Residential batteries are operated by households for varied purposes (backup power, self-consumption, bill management). Commercial and utility-scale batteries are typically controlled by profit-maximising algorithms that engage in "value stacking," capturing revenues not only from wholesale energy arbitrage but also from reserve markets, ancillary services, intraday trading, and imbalance market participation. Suppliers may use batteries to balance their customer portfolios and manage profile risks. These real-world behaviours will produce different dispatch patterns than the system-optimal dispatch computed by the model.

These caveats do not invalidate the analysis, but they do suggest that real-world outcomes will fall somewhat short of the theoretical potential indicated by the simulations. The results should be interpreted as indicating what is achievable under idealised coordination, providing a benchmark against which real-world performance can be assessed.

3.5. Exogenous Inputs to the Simulations

This section presents the key exogenous inputs to the simulations: installed generation and storage capacities, renewable energy production, and electricity demand. These inputs are derived from the ENTSO-E TYNDP 2024 National Trends scenarios, with the exception of stationary battery capacities which are varied according to our scenario structure. Exogenous inputs are fixed and should therefore not be confused with the optimisation results.

3.5.1. Installed capacities

3.5.1.1. Belgium

Figure 3 provides an overview of the total installed capacities by technology for Belgium in 2030 and 2040. For each target year, two bars are displayed corresponding to the LOW BAT and HIGH BAT scenario variants. It should be noted that all non-battery capacities remain identical across the DUMB, SMART, and V2G electric vehicle scenarios, as these variants only affect EV charging behaviour rather than the installed generation fleet.

For Belgium in 2030, the generation mix is characterised by 2 GW of nuclear capacity (reflecting the planned extension of Doel 4 and Tihange 3), 13.6 GW of solar PV, 4.4 GW of offshore wind, 5.3 GW of onshore wind, and 4.6 GW of combined gas-fired capacity (3.5 GW CCGT and 1.1 GW OCGT).

Additional capacity includes the “other” thermal units including must-run units associated with heat delivery (CHP’s) and 1.30 GW of pumped hydro storage. The presence of nuclear capacity substantially affects the flexibility landscape: nuclear plants provide baseload generation but are assumed to have limited operational flexibility, creating specific needs for other resources to manage variability in residual load. By 2040, the installed base evolves substantially. Nuclear capacity is phased out entirely in the TYNDP National Trends scenario, whilst solar PV nearly doubles to 26.3 GW and onshore wind increases to 7.5 GW. This **near-doubling of solar PV capacity will dramatically increase daily flexibility requirements, as solar generation creates predictable midday peaks that must be absorbed, stored, exported or curtailed**, making this the primary driver of short-term flexibility needs.

Offshore wind capacity remains stable at 4.36 GW, reflecting current project pipelines rather than theoretical potential; Belgium's limited exclusive economic zone constrains offshore expansion relative to neighbours like the United Kingdom or Germany. The thermal fleet transitions as well, with hydrogen-fuelled CCGT (3.4 GW) appearing alongside conventional CCGT (5.5 GW), whilst OCGT capacity decreases to 0.2 GW. The emergence of hydrogen-fuelled CCGT represents a new flexibility resource that competes with batteries and EVs for balancing services whilst also providing firm dispatchable capacity that storage cannot fully replicate.

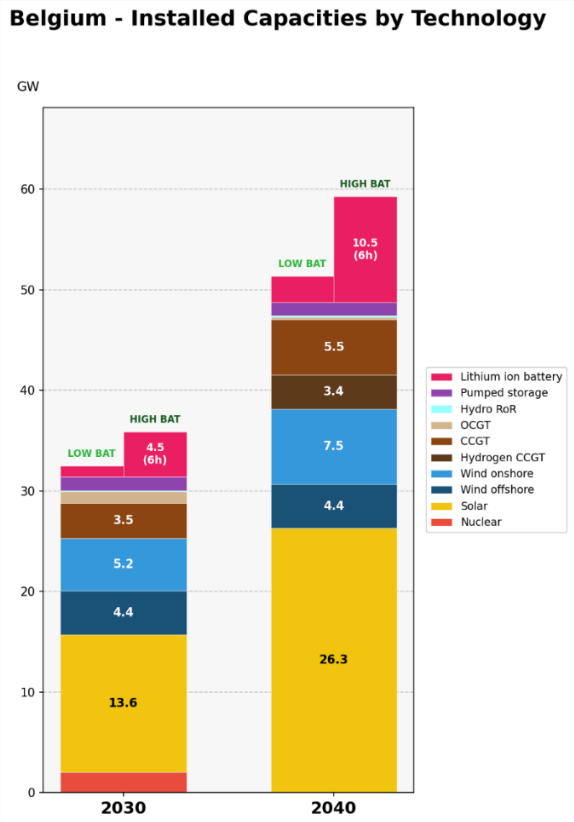


Figure 3: Installed electricity generation and storage capacities in Belgium by technology for 2030 and 2040, showing LOW BAT and HIGH BAT scenario variants

3.5.1.2. Stationary Battery Capacities

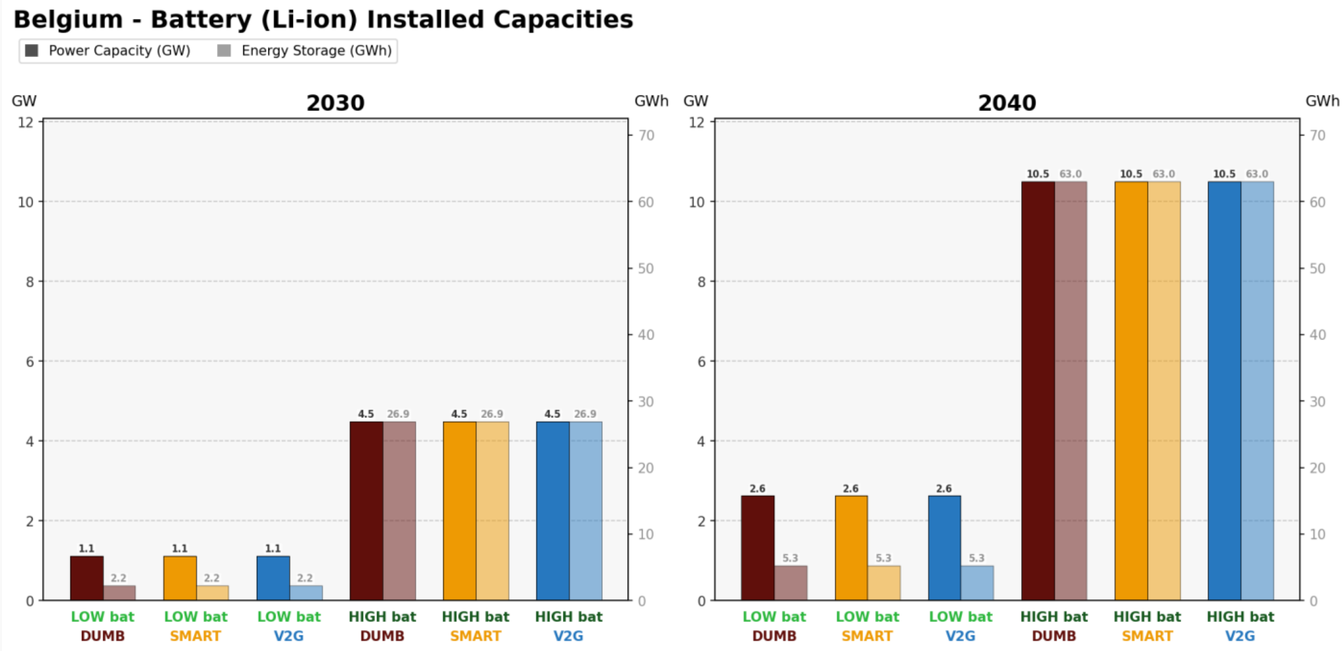


Figure 4: Li-ion battery installed power capacity (GW) and energy storage capacity (GWh) in Belgium for the LOW BAT and HIGH BAT scenario variants

In the LOW BAT scenario for Belgium, battery power capacity amounts to 1.1 GW in 2030, increasing to 2.6 GW by 2040. These batteries are assumed to have a storage duration of 2h, resulting in energy capacities of 2.2 GWh and 5.3 GWh respectively. In contrast, the HIGH BAT scenario assumes significantly higher deployments: 4.5 GW of battery power in 2030, growing to 10.5 GW in 2040. Crucially, these HIGH BAT systems are also assumed to have longer storage duration of 6 hours, yielding energy storage capacities of 26.9 GWh in 2030 and 63 GWh in 2040.

This significant difference creates a natural experiment for examining how the availability of one flexibility resource affects the utilisation and value of others.

The range is deliberately wider than typical sensitivity analyses, chosen to reveal how system behaviour changes across dramatically different flexibility landscapes.

As the core focus of this study involves examining the impact of varying stationary battery capacities, Figure 4 presents the assumed lithium-ion battery capacities in greater detail. Battery capacities differ substantially between the LOW BAT and HIGH BAT scenarios, both in terms of power rating (GW) and energy storage capacity (GWh).

3.5.1.3. Cross-Country Comparison

To contextualise Belgium's capacity assumptions within the broader European landscape Figure 5 compares installed capacities across Belgium, Germany, France, the Netherlands, and the United Kingdom.

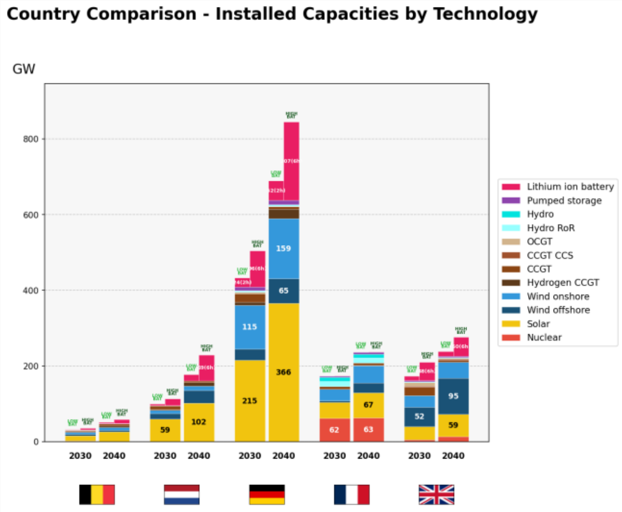


Figure 5: Installed electricity generation and storage capacities by technology for Belgium, Germany, France, the Netherlands, and the United Kingdom in 2030 and 2040

The installed capacity profiles differ markedly across countries, reflecting their distinct energy policies and resource endowments. Germany possesses by far the largest renewable capacity, with 215 GW of solar PV and 115 GW of onshore wind in 2030, growing to 366 GW and 159 GW respectively by 2040. France maintains substantial nuclear capacity (62-63 GW) alongside significant hydropower resources (over 23 GW combined). The United Kingdom distinguishes itself through its ambitious offshore wind deployment, reaching 52 GW in 2030 and 95 GW in 2040. The Netherlands, despite its relatively small geographic size, assumes 59 GW of solar PV in 2030, expanding to 102 GW by 2040.

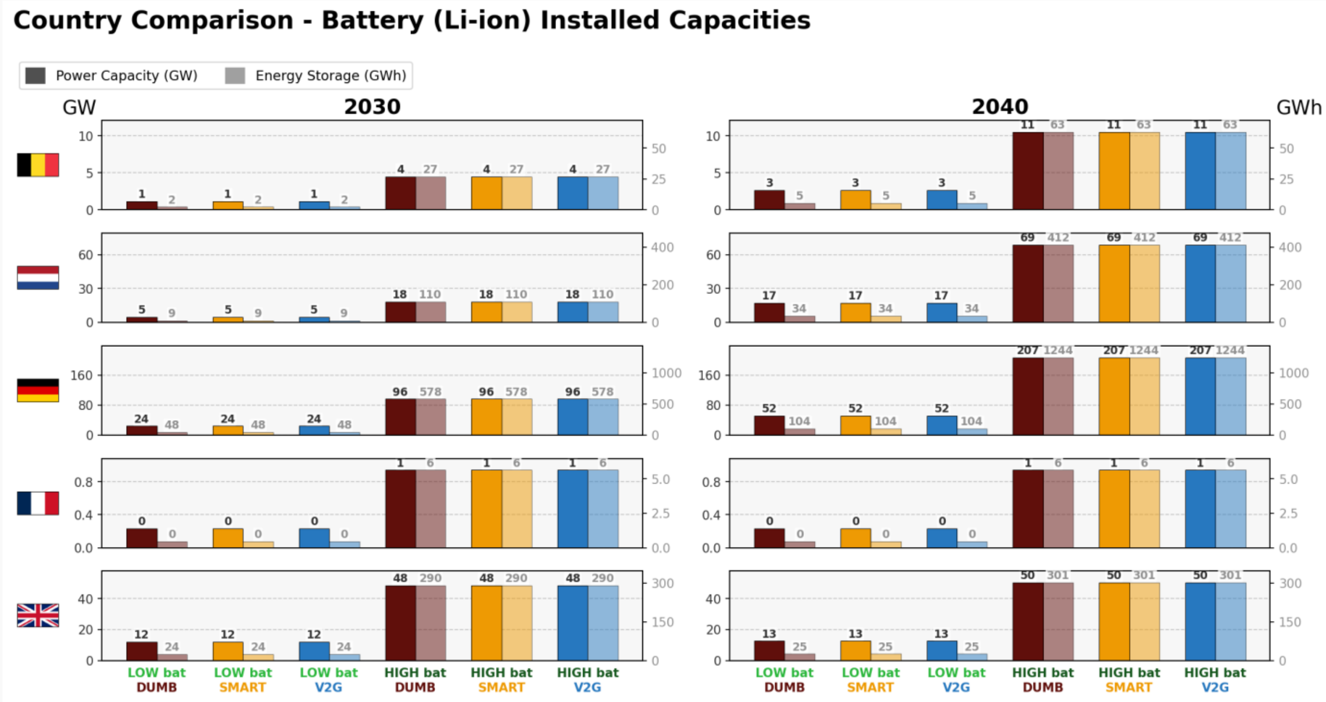


Figure 6: Li-ion battery installed power (GW) and energy storage capacity (GWh) across Belgium, Germany, France, the Netherlands, and the UK

Battery capacity assumptions also vary considerably across countries (Figure 6). Germany leads in absolute terms, with LOW BAT capacities of 24 GW in 2030 and 52 GW in 2040, and HIGH BAT capacities of 96 GW and 207 GW respectively. The Netherlands assumes substantial battery deployment relative to its size (18 GW HIGH BAT in 2030, 69 GW in 2040), whilst the United Kingdom maintains HIGH BAT capacities around 48-50 GW across both time horizons. France represents an outlier with very modest battery assumptions of only 0.23-0.94 GW, reflecting its reliance on nuclear baseload and hydropower for system flexibility.

3.5.2. Wind and Solar PV Generation

The simulations are driven by hourly wind and solar PV generation profiles derived from historical weather data, scaled to the installed capacities described above. The renewable generation values presented here represent pre-curtailment potential: what these assets could produce if the system were able to absorb all their output (Figure 7). Whether and how much renewable generation is curtailed is determined endogenously within the simulation, based on system conditions, flexibility availability, and cross-border exchange opportunities. The difference between pre-curtailment potential and actual (post-curtailment) generation represents a key metric for assessing system flexibility.

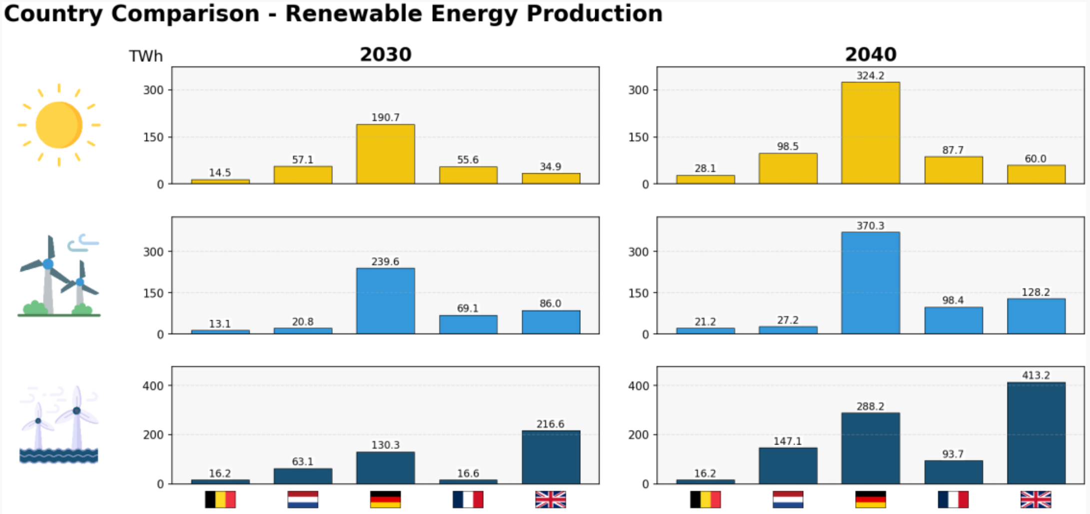


Figure 7: Pre-curtailment renewable energy production

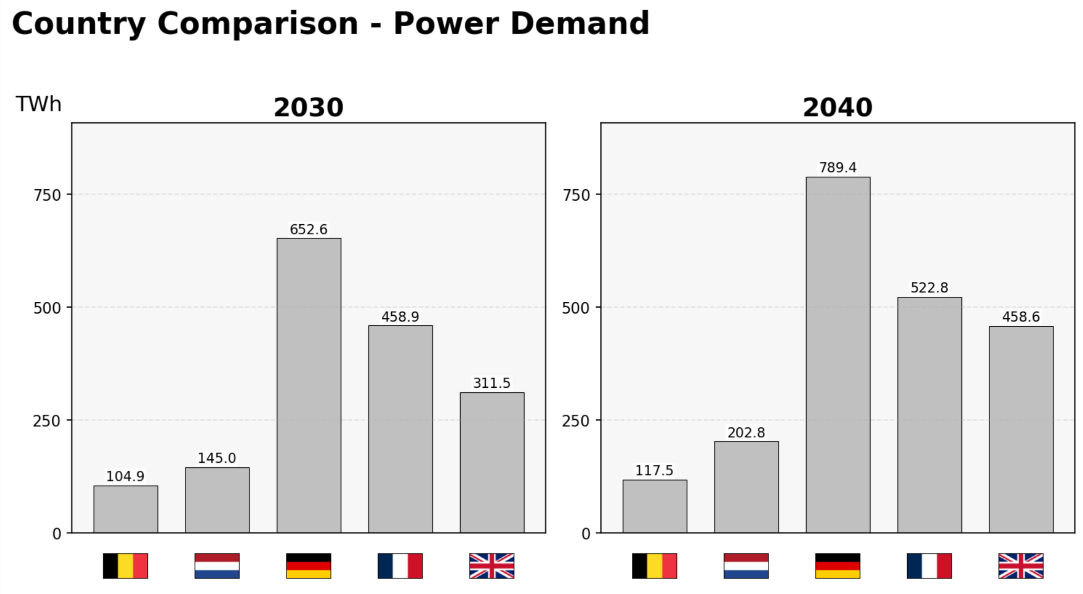


Figure 8: Regular power demand excl. demand determined endogenously (EV's, heat pumps, stationary batteries, elektrolysers)

Belgium's renewable mix is roughly balanced between solar PV, onshore wind, and offshore wind, which creates more complex flexibility needs than systems dominated by a single technology. Solar generation creates pronounced daily patterns with predictable midday peaks, whilst wind generation creates multi-day variations driven by weather systems. This combination requires flexibility resources that are effective at both timescales: daily cycling to absorb solar peaks and manage morning/evening demand periods, and the ability to respond to longer wind droughts or sustained high-wind periods. The distinct temporal characteristics of solar and wind have different implications for the value of short-duration storage (well-suited to daily solar patterns) versus longer-duration resources.

3.5.3 Electricity Demand

The electricity demand profiles used in the simulations are also derived from the ENTSO-E TYNDP 2024 scenarios, reflecting projected consumption patterns for 2030 and 2040. It is important to distinguish between different components of electricity demand as represented in the model.

"Regular" electricity demand refers to consumption that is exogenous to the flexibility optimisation: residential, commercial, and industrial loads that follow assumed hourly profiles and are not subject to demand-side flexibility within the model. This excludes the electricity consumption of electric vehicles and stationary batteries, which is determined endogenously by the optimisation (Figure 8).

Between 2030 and 2040, regular electricity demand grows substantially, reflecting continued electrification of end-uses beyond transport. This includes the deployment of heat pumps for space and water heating, the growth of data centres, and broader industrial electrification. The demand from heat pumps is modelled endogenously within ACSG but is not assumed to be flexible in these simulations; heat pump operation follows thermal comfort requirements rather than electricity price signals. This report does not focus on heat pump flexibility, though it represents an additional potential flexibility resource that could be examined in future work.

The growth in overall electricity demand between 2030 and 2040 has important implications for flexibility value. As the electricity system grows larger, the absolute benefits of efficient system operation (enabled by flexibility) increase correspondingly. The larger the overall system, the more costly it becomes to operate inefficiently due to insufficient flexibility, and the more valuable flexibility resources become in absolute terms.

4. Results

4.1. National Production and Consumption

4.1.1. Annual Figures

4.1.1.1. Belgium

Figure 9 presents the annual electricity production, consumption, and net imports for Belgium across all scenario variants for 2030 and 2040.

In 2030, Belgium's total electricity consumption ranges from 121 to 125 TWh depending on the scenario variant, whilst domestic production amounts to approximately 87-89 TWh. **The resulting net import requirement of 33-36 TWh reflects Belgium's structural position as a net electricity importer**, relying on interconnections with France, the Netherlands, Germany, and the United Kingdom to meet domestic demand.

By 2040, total electricity consumption increases substantially to 147-158 TWh, reflecting continued electrification of transport (EVs), heating (heat pumps), and other end-uses. This 21-27% increase in consumption relative to 2030 illustrates the scale of demand growth that flexibility resources will need to accommodate. **Domestic production rises to approximately 100-105 TWh, but the import requirement also grows to 43-53 TWh.** The larger the electricity system becomes, the more important it is to operate efficiently; insufficient flexibility forces reliance on potentially expensive imported electricity or the curtailment of domestic renewable generation.

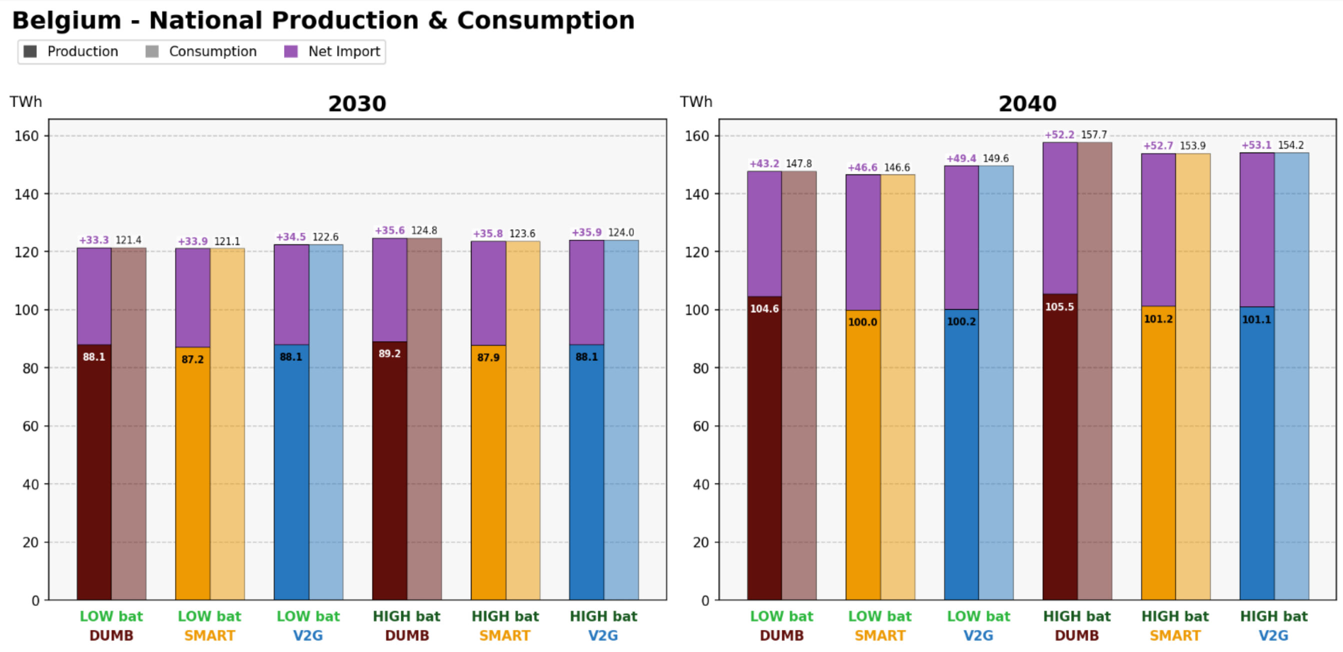


Figure 9: Belgium's total annual electricity production, consumption, and net imports by scenario variant for 2030 and 2040

The scenario variants reveal several patterns in the electricity balance. **Consumption is systematically higher in HIGH BAT scenarios compared to LOW BAT scenarios**. This reflects the fact that stationary batteries themselves consume electricity (to charge) and incur approximately 8-9% round-trip energy losses. For example, in 2040 HIGH BAT scenarios, consumption reaches 154-158 TWh compared to 147-150 TWh in LOW BAT scenarios – an increase mostly attributable to battery cycling activity (cf. Section 4.5 for more detail).

Net imports tend to be somewhat higher in the V2G scenarios compared to DUMB scenarios. At first glance this may appear counterintuitive: one might expect that additional domestic flexibility would reduce import dependency. However, the V2G scenarios show higher total consumption (EVs discharge and then must recharge), and the model optimises system-wide costs including the opportunity to import during periods of low international prices. When domestic EVs can provide peak flexibility, Belgium can afford to import more during off-peak periods when neighbouring countries have surplus renewable generation, effectively "arbitraging" across borders.

Figure 10 provides a breakdown of domestic electricity production by technology, revealing how the generation mix shifts across scenarios.

The production mix demonstrates clear substitution dynamics enabled by flexibility. In 2030, gas-fired generation (CCGT plus OCGT) totals 15.85 TWh in the LOW BAT DUMB scenario but falls to 13.14 TWh in the HIGH BAT V2G scenario – a 17% reduction. This substitution occurs because **flexible EVs and batteries absorb renewable surpluses** (enabling more wind and solar utilisation rather than curtailment) **and reduce peak demand that would otherwise require gas-fired generation**. The mechanism is straightforward: by "filling the valleys" with flexible charging during periods of abundant renewable output, and "shaving the peaks" by reducing demand

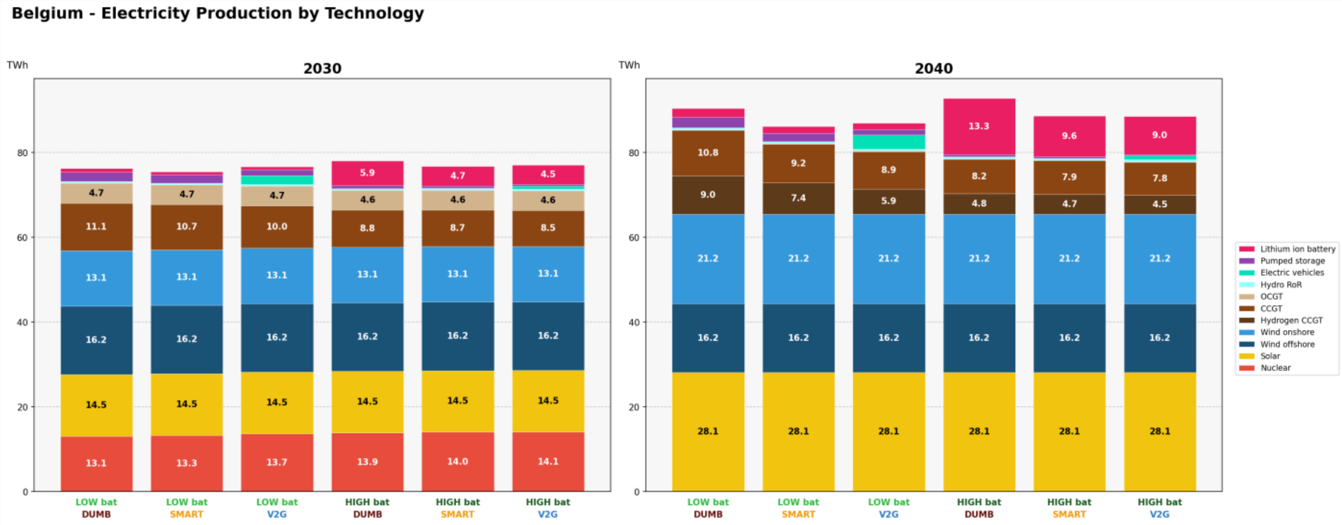


Figure 10: Annual electricity production in Belgium by technology for 2030 and 2040

(or, in V2G scenarios, injecting power) during periods of scarcity, flexibility resources reduce the operating hours required from gas turbines.

Nuclear production in 2030 shows the opposite pattern, increasing slightly from 13.10 TWh (LOW BAT DUMB) to 14.08 TWh (HIGH BAT V2G). This occurs because flexibility resources allow nuclear plants to operate in a more stable baseload pattern, avoiding the output reductions that would otherwise be necessary when renewable generation peaks exceed what the system can absorb. **Flexibility effectively "makes room" for nuclear by absorbing excess generation during periods when nuclear would otherwise need to ramp down**.

By 2040, nuclear capacity is phased out in the National Trends scenario, and gas-fired generation includes both conventional CCGT and hydrogen-fuelled CCGT. Total gas-fired generation (conventional plus hydrogen) reaches 19.93 TWh in the LOW BAT DUMB scenario but falls to 12.38 TWh in the HIGH BAT V2G scenario – a 38% reduction. **The greater flexibility value in 2040 reflects the substantially larger solar PV capacity** (26.3 GW versus 13.6 GW in 2030), **which creates more pronounced daily arbitrage opportunities that batteries and EVs can exploit**.

4.1.1.2. Cross-Country Comparison

Before examining the simulation results, it is instructive to consider the recent historical electricity trade positions of the countries studied. Table 4 presents net electricity imports for 2020-2025 based on data from Ember.

Table 4: Historical Net Electricity Imports (TWh), 2020-2025

Year	UK	DE	NL	FR
2020	18.3	−19.0	−2.7	−45.0
2021	24.7	−18.6	0.3	−44.9
2022	−4.3	−27.3	−4.3	15
2023	23.3	9.2	−5.7	−50.5
2024	33.2	26.3	−4.2	−89.9
2025	30	22	−14.0	−92.0

Positive values indicate net imports; negative values indicate net exports. 2025 data reflects estimates. Source: Ember (2025) ember-energy.org/data/yearly-electricity-data/.

Several patterns emerge from these historical figures. France has traditionally been Europe's largest electricity exporter, with its nuclear fleet generating substantial surpluses for neighbouring markets.

The exception was 2022, when widespread maintenance issues and corrosion problems in the French nuclear fleet temporarily transformed France into a net importer (15 TWh)—a striking reversal that contributed to the European energy crisis of that year. Since then, nuclear availability has recovered, and French exports have surged to record levels (92 TWh in 2025).

Germany has undergone a significant transition. Until 2022, Germany was a consistent net exporter (19-27 TWh annually) despite its nuclear phase-out, as its large coal and renewable fleet produced surpluses. However, beginning in 2023, Germany shifted to become a net importer (9-26 TWh annually), reflecting the final closure of its remaining nuclear plants, reduced coal generation, and growing electricity demand. This structural shift has implications for all of Germany's neighbours, including Belgium.

The Netherlands has been a modest but consistent net exporter in recent years (3-14 TWh annually), leveraging its gas-fired generation fleet and growing renewable capacity to supply neighbouring markets.

The United Kingdom has historically been a significant net importer, relying on interconnectors to France, Belgium, the Netherlands, and Norway to meet domestic demand. In most recent years, the UK has imported 18-33 TWh annually. The sole exception was 2022, when French nuclear problems reduced available imports from France, and the UK briefly became a marginal net exporter (4 TWh).

With this historical context established, Figure 11 compares the simulated national electricity balances for 2030 and 2040. The simulation results project several notable shifts from recent historical patterns.

France remains a substantial net exporter in 2030 (exporting 39-59 TWh depending on scenario), consistent with its historical position. **However, by 2040, the simulations project that France will become a net importer** (21-32 TWh). This reversal reflects projected demand growth (electrification of transport and heating) outpacing the addition of new generation capacity in the National Trends scenario. If this transition materialises, it would have significant implications for Belgium and other countries that have historically relied on French exports during periods of high demand.

Germany is projected to be a net importer in 2030 (24-31 TWh), continuing the pattern established since 2023. However, **by 2040, the simulations show Germany becoming a slight net exporter (7-13 TWh) as its enormous renewable deployment** (366 GW solar, 159 GW onshore wind) begins to generate persistent surpluses. The scenario with the largest German exports is HIGH BAT V2G, where abundant flexibility enables Germany to absorb its renewable output and export surpluses rather than curtailing generation. This projected reversal back to net exporter status would represent a significant shift in European electricity flows.

The Netherlands evolves from near-balance in 2030 (ranging from 3 TWh net export in HIGH BAT scenarios to 1 TWh net import in LOW BAT scenarios) **to consistent net importer by 2040** (13-17 TWh). Interestingly, in the HIGH BAT 2030 scenarios, the Netherlands becomes a net exporter, as high battery deployment enables it to absorb more domestic solar generation and export during peak demand hours in neighbouring countries. The projected shift to net importer status by 2040 contrasts with the recent historical pattern of modest exports.

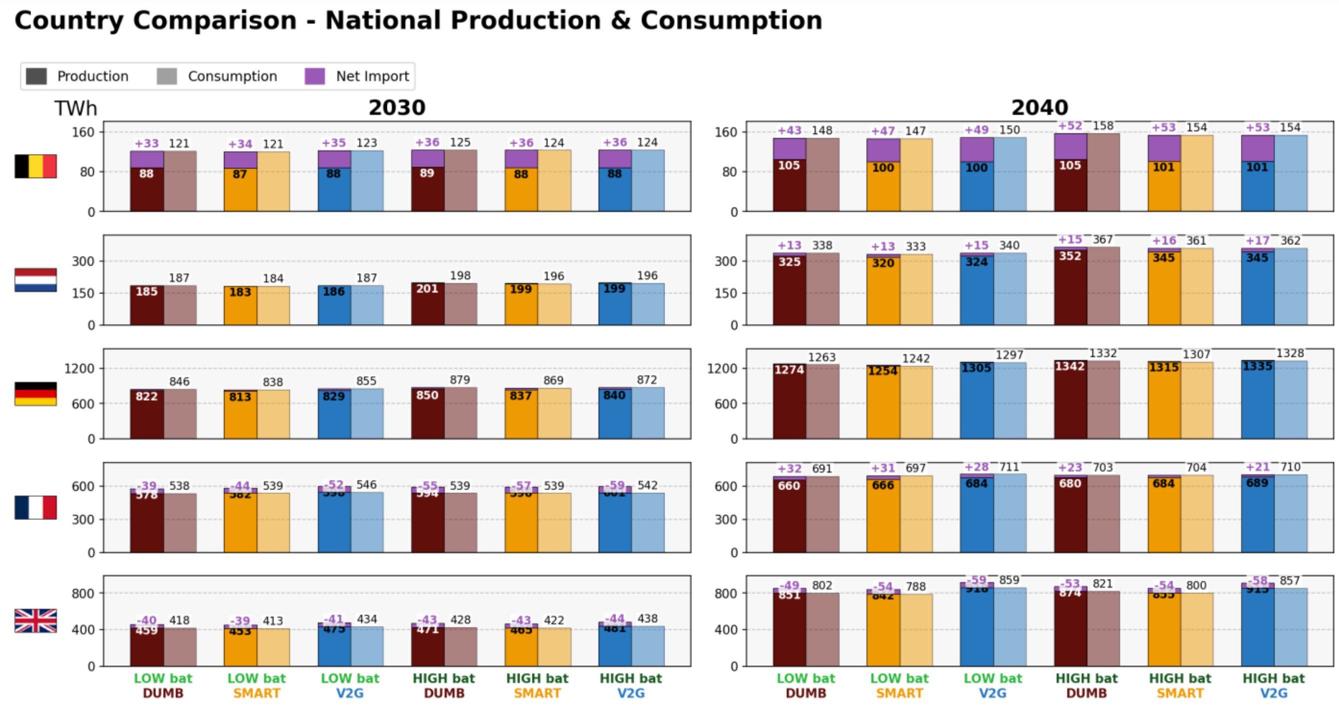


Figure 11: National electricity production, consumption, and net imports for Belgium, Germany, France, the Netherlands, and the United Kingdom in 2030 and 2040

The United Kingdom shows the most dramatic projected change from historical patterns. Whereas the UK has historically been a consistent net importer (18-33 TWh annually in recent years), the simulations project it to become a substantial net exporter by 2030 (40-44 TWh) and even more so by 2040 (49-59 TWh). This transformation reflects the ambitious offshore wind deployment assumed in the National Trends scenario: 52 GW by 2030 and 95 GW by 2040. If these deployment targets are achieved, the UK's offshore wind resources would generate far more electricity than domestic demand, with surpluses exported via interconnectors to continental Europe. However, it should be noted that achieving such deployment levels faces considerable challenges including supply chain constraints, grid connection bottlenecks, and consenting processes. The UK's partial insulation from the continental grid (connected via submarine cables rather than fully meshed AC connections) also means that export capacity will depend critically on interconnector expansion

Belgium remains a structural net importer across all scenarios: 33-36 TWh in 2030 and 43-53 TWh in 2040. This is consistent with Belgium's historical position and reflects its limited domestic generation resources relative to demand. Belgium's import dependency means that the value of its domestic flexibility resources depends significantly on what happens in neighbouring countries.

If France transitions from exporter to importer as projected, Belgian flexibility becomes more valuable for managing periods when French supply is constrained. Conversely, if Germany and the UK deploy massive renewable capacity and become net exporters, Belgian flexibility resources face greater competition, as imports may be available at competitive prices during periods of renewable surplus.
These cross-border dynamics underscore a critical insight: **the electricity trade positions of European countries are projected to shift substantially over the coming 15-20 years**, with implications for market prices, security of supply, and the value of flexibility resources across the interconnected system.

4.1.2. Hourly Dispatch in Winter versus Summer

Whilst annual figures provide an essential overview of the electricity balance, the hourly dispatch patterns reveal how flexibility resources operate in practice and how production technologies interact throughout the day and across seasons. This section presents illustrative examples from January (winter: high demand, lower solar) and July (summer: lower demand, high solar) to demonstrate the temporal dynamics of production and consumption.

4.1.2.1. Belgium

Figure 12 presents the hourly electricity production in Belgium for January and July across 2030 and 2040, using the HIGH BAT SMART scenario as the illustrative case. This scenario, with high battery deployment and smart EV charging, demonstrates relevant flexibility dynamics.

January (Winter)

January represents a challenging period for the Belgian electricity system: demand is high due to heating requirements and shorter daylight hours, whilst solar generation is limited. In January 2030, total domestic production amounts to 7.6 TWh for the month, with gas-fired generation (CCGT and OCGT combined) contributing 2.3 TWh (30% share), wind (onshore plus offshore) providing 2.9 TWh (38%), nuclear contributing 1.6 TWh (20%), and solar adding 0.6 TWh (9%). Batteries discharge 0.20 TWh (2.6% of monthly production), primarily supporting morning and evening demand peaks.

The hourly data reveal the operational patterns underlying these monthly totals. Nuclear operates as baseload at a constant 2 GW throughout the month. Gas-fired generation is more dynamic, ranging from 0.9 GW during periods of high wind output to 4.4 GW during calm, high-demand periods, with a mean output of about 3 GW.

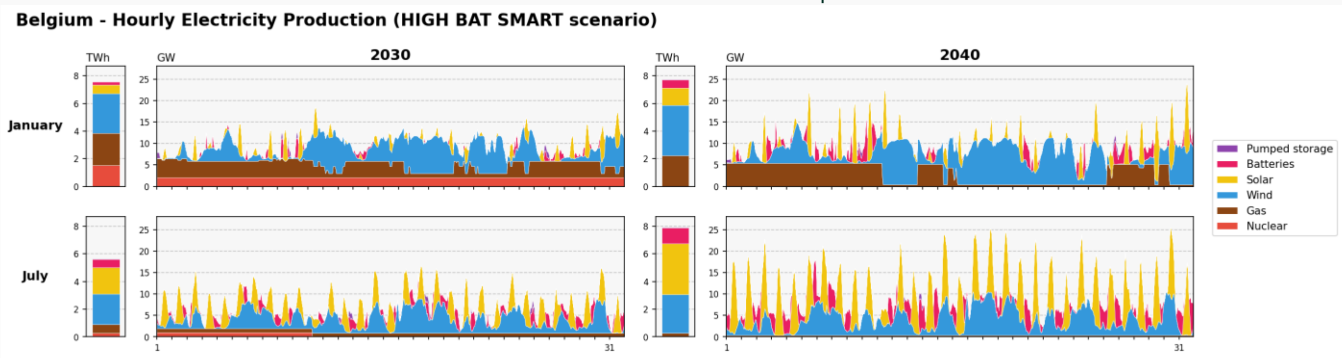


Figure 12: Hourly electricity production in Belgium for January and July in 2030 and 2040 (HIGH BAT SMART scenario). For visual clarity, technologies are aggregated: "Gas" combines CCGT and OCGT; "Wind" combines onshore and offshore wind. Smaller technologies such as hydro run-of-river, other thermal (CHP), and other renewables are omitted from the figure but included in totals.

Wind generation exhibits substantial variability, ranging from near-zero during calm periods to almost 9 GW during peak production periods. Battery discharge peaks at 4.5 GW during specific high-demand hours, demonstrating its role in managing peak loads.

By January 2040, the picture shifts substantially. Nuclear capacity is phased out entirely (as assumed in the underlying TYNDP scenario), leaving the major roles for gas, wind, solar, and batteries to meet demand. Monthly production rises to 7.8 TWh, with wind now contributing 3.7 TWh (47%), gas providing 2.2 TWh (29%), solar adding 1.2 TWh (16%), and batteries discharging 0.62TWh (8%) – three times more than in 2030.

The battery contribution triples due to two factors: the near-doubling of solar capacity (from 14 GW to 26 GW) creates more pronounced midday production peaks even in winter, and the larger installed battery fleet in 2040 can capture more of the resulting arbitrage opportunities. Battery discharge now peaks at almost 10 GW, more than double the 2030 peak, reflecting both the larger installed battery fleet and its more intensive utilisation.

July (Summer)

July presents a fundamentally different operational challenge: demand is lower (no heating requirement), but solar generation creates pronounced midday peaks. In July 2030, monthly production amounts to 5.63 TWh – 25% less than January. Solar PV dominates with 1.9 TWh (34%), whilst wind contributes 2.2 TWh (39%). Nuclear production drops dramatically to just 0.3 TWh (5%), as the plant reduces output during periods of solar surplus. Gas-fired generation falls to 0. TWh (12%), operating primarily at minimum levels.

The transformation in nuclear operations is striking: whilst nuclear ran at constant 2 GW throughout January, in July it averages just 0.3 GW with high variability (standard deviation of 0.5 GW), effectively cycling to accommodate solar generation.

Meanwhile, batteries discharge 0.6 TWh (10% of production) – nearly three times more than in January – performing daily arbitrage cycles: charging during midday solar peaks and discharging during evening demand peaks when solar output wanes.

By July 2040, solar becomes the dominant technology, generating 3.7 TWh (46% of monthly production). Wind contributes 2.8 TWh (35%), whilst gas-fired production collapses to just 0.3 TWh (3%). Batteries discharge 1.2 TWh (15%), twice the July 2030 level, with peak discharge reaching 10.5 GW. The hourly patterns reveal the essential role of storage: solar output peaks at 18 GW during midday hours, far exceeding demand, whilst batteries absorb this surplus and re-inject it during evening hours when solar output falls to zero.

The contrast between winter and summer operations illustrates why daily flexibility needs grow substantially from 2030 to 2040. **The near-doubling of solar capacity creates much larger swings between midday surplus and evening deficit, requiring storage, flexible EV charging, cross-border trade, or curtailment to manage effectively**.

4.1.2.2. Country Comparison

To contextualise Belgium's dispatch patterns within the broader European landscape, Figure 13 presents comparable hourly production data for Germany, France, the Netherlands, and the United Kingdom.

Germany

Germany operates at an entirely different scale, with monthly production ranging from 55–105 TWh compared to Belgium's 6–8 TWh. In January 2030, wind dominates with 34 TWh (62%), whilst gas provides 13 TWh (23%) and solar adds 6 TWh (11%). Batteries contribute 2 TWh (3%). The hourly statistics reveal the massive scale of German renewable variability: wind output ranges from around 4 GW to 115 GW, averaging 45 GW. Solar peaks at nearly 57 GW during midday hours despite being January.

By 2040, the German system transforms further. In January 2040, wind provides 61 TWh (76%), gas falls to just 3 TWh (4%), and batteries discharge 4.5 TWh (6%).

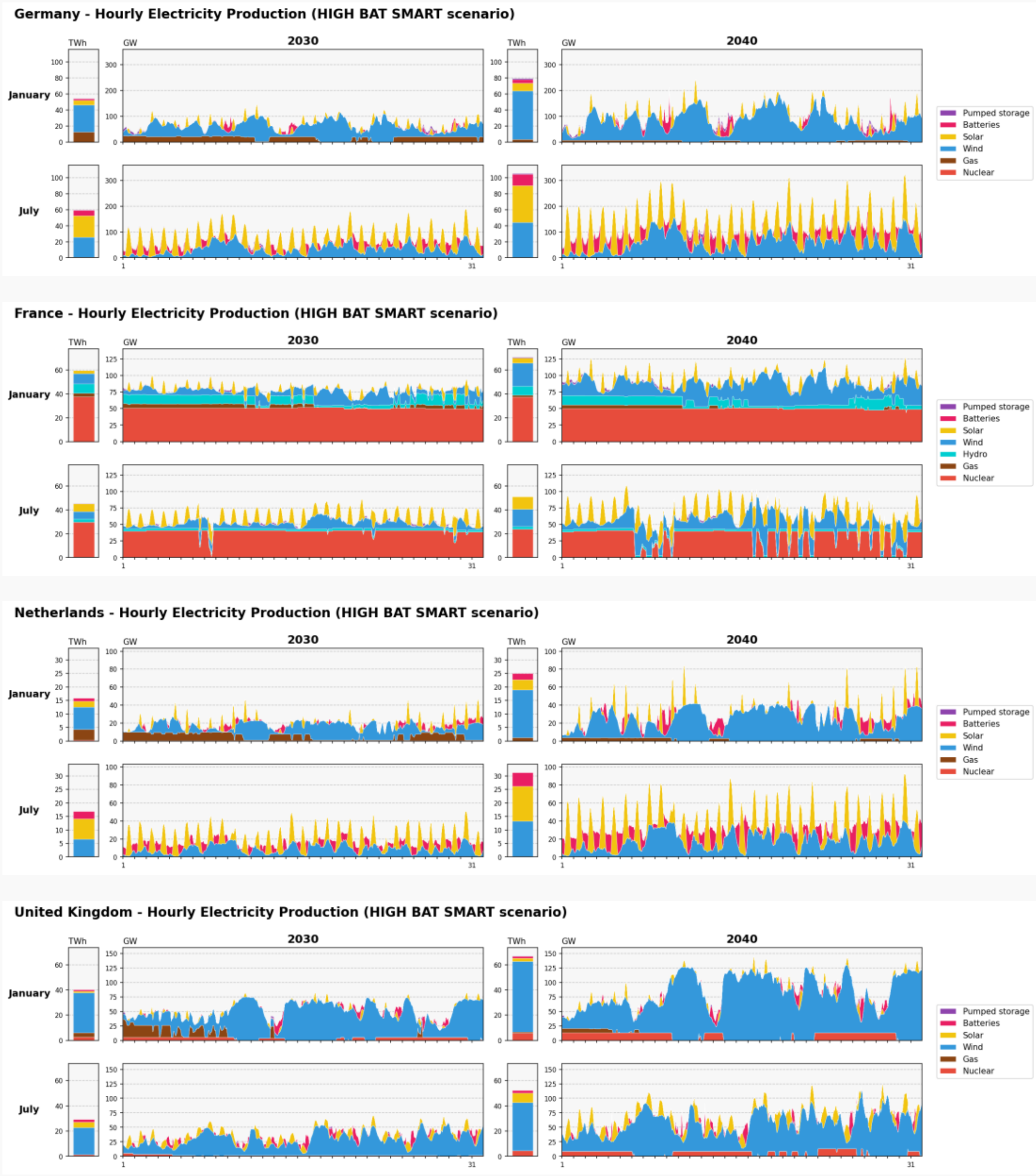


Figure 13: Hourly electricity production for January and July in 2030 and 2040 (HIGH BAT SMART scenario) for Germany, France, the Netherlands, and the United Kingdom. Technology aggregations follow Belgium conventions (Figure 12), except for France where "Hydro" (run-of-river and reservoir combined) is shown separately given its significance in the French generation mix.

Wind output can now reach 186 GW during favourable conditions, whilst **battery discharge peaks at 177 GW – representing the enormous scale of storage required to manage German renewable variability**. Total hourly production of the major technologies swings between 18 GW and 245 GW.

July 2040 demonstrates extreme solar dominance: solar generates 46 TWh (44%), wind adds 44 TWh (42%), and batteries discharge 14 TWh (14%). Gas-fired generation collapses to just 0.2 TWh – essentially negligible. Solar output peaks at an extraordinary 229 GW during midday hours, whilst batteries discharge up to 106 GW during evening peaks. Total production reaches 327 GW during sunny, windy periods.

France

France exhibits fundamentally different dynamics due to its nuclear-dominated generation mix and significant hydropower resources. In January 2030, nuclear provides 38 TWh (63%), hydro contributes 8 TWh (13%), wind adds 8.5 TWh (14%), and gas provides just 3 TWh (5%). Batteries discharge only 0.07 TWh – negligible compared to other countries.

Nuclear operates between 50 and 52 GW with remarkable stability. Hydro provides valuable flexibility, ranging from 3 to 17 GW, whilst wind varies from 1 to 29 GW. The minimal battery utilisation reflects France's inherent system flexibility: nuclear provides stable baseload, hydro manages variability, and the combination reduces the need for additional storage.

In July 2030, nuclear remains dominant at 30 TWh (66%), but gas-fired generation falls to zero – the system has sufficient flexibility from nuclear ramping and hydro to balance renewable variability without thermal backup. By July 2040, nuclear reduces to 24 TWh (46%) as the plant cycles more aggressively to accommodate higher solar penetration (10 TWh, 20%). Nuclear output varies dramatically in the model results, ranging from 0 GW during peak solar hours to 41 GW during periods of low renewable output.

It should be noted that this dramatic nuclear cycling is partly an artefact of how nuclear plants are represented in dispatch optimisation models. In practice, the French nuclear fleet would likely ramp up and down more gradually in a coordinated fashion, as EDF has historically demonstrated through its well-established load-following practices. The model's cost-minimising logic can produce sharper transitions than would occur in reality, where operational constraints, safety margins, and coordination protocols smooth out such fluctuations. Nevertheless, the underlying dynamic is real: high solar penetration in 2040 will require French nuclear to operate more flexibly than it does today, representing a fundamental shift from baseload to load-following operation.

The Netherlands

The Netherlands presents an interesting contrast to Belgium: similar in geographic size but with substantially higher solar penetration. In January 2030, wind provides 8 TWh (52%), gas contributes 4 TWh (25%), and solar adds 2 TWh (14%). Batteries discharge 1 TWh (7%) – a higher share than Belgium, reflecting the solar-dominated system's daily flexibility needs.

Solar output in the Netherlands peaks at 32 GW even in January, and batteries peak at 10 GW. By January 2040, wind contributes 18 TWh (71%), gas falls to 1.2 TWh (5%), and batteries discharge 2.3 TWh (9%). Solar peaks at 54 GW and batteries at 30 GW.

July patterns are even more solar-intensive. In July 2030, solar provides 7.5 TWh (44%), wind adds 6.5 TWh (38%), and batteries discharge 2.8 TWh (17%) – the highest battery share among the countries studied. Gas falls to just 0.2 TWh (1%). By July 2040, solar reaches 13 TWh (41%), wind provides 13 TWh (42%), and batteries discharge 5 TWh (16%). **Battery discharge peaks at 42 GW during evening hours, representing intensive daily cycling to manage the solar-driven production pattern**.

United Kingdom

The United Kingdom exhibits the most wind-dominated system among the countries studied, reflecting its ambitious offshore wind deployment. In January 2030, wind provides 31 TWh (78%), gas contributes 3.5 TWh (9%), nuclear adds 3 TWh (7%), and batteries discharge 1.2 TWh (3%). Wind output ranges from 5 GW to 76 GW, averaging 42 GW.

By January 2040, wind dominance intensifies: 56 TWh (84%), with nuclear at 6 TWh (9%), batteries at 1.7 TWh (3%), and gas at less than 1 TWh. Wind output now ranges from 10 to 128 GW, reflecting the massive scale of offshore deployment. Total production reaches 145 GW during favourable conditions.

In July, the UK system requires essentially no gas-fired generation. July 2030 shows wind at 21 TWh (73%), solar at 4 TWh (15%), batteries at 2 TWh (8%), and nuclear at 1.4 TWh (5%) – with gas at zero. **The UK's wind-dominated mix creates different flexibility patterns than solar-dominated systems: variability occurs over multi-day weather cycles rather than predictable daily patterns, which affects how storage resources are dispatched**.

Comparative Insights

The cross-country comparison reveals several key patterns. First, **battery utilisation correlates strongly with solar penetration**: the Netherlands shows the highest battery share (16–17% in summer months), whilst France shows the lowest (well under 1%) due to its nuclear-hydro flexibility. Belgium sits between these extremes.

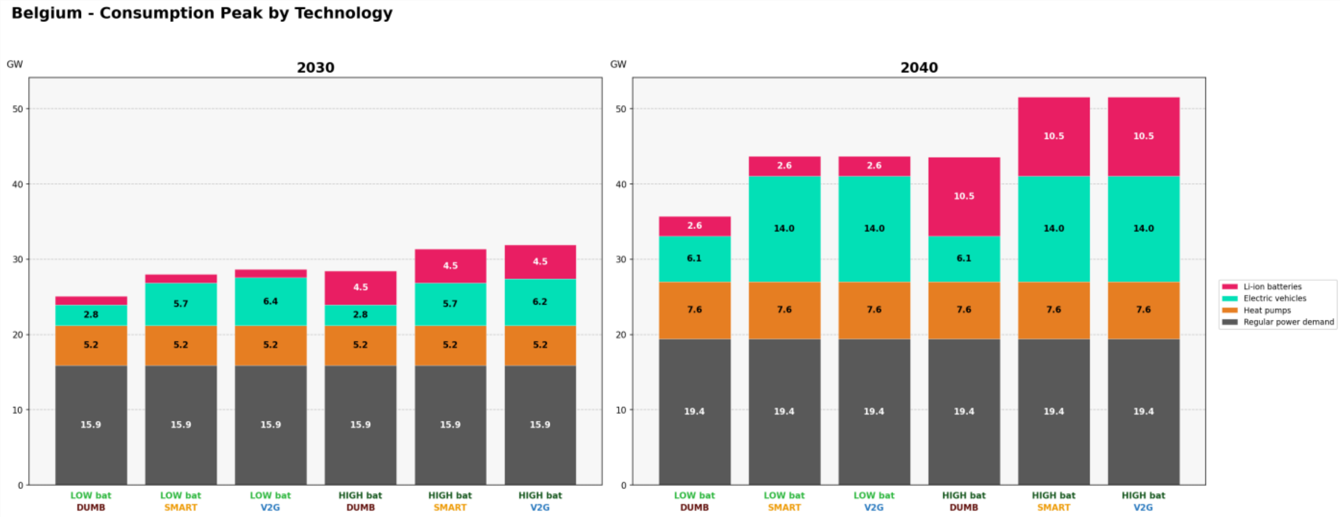


Figure 14: Peak consumption by technology in Belgium for 2030 and 2040. Values represent the maximum instantaneous consumption for each technology category individually, not simultaneous peaks.

Second, **gas-fired generation serves as the "balancer of last resort" but its role varies dramatically by country**. In France, gas generation can fall to zero for entire months due to nuclear-hydro flexibility. In Germany and the Netherlands, gas similarly approaches zero in summer 2040. In Belgium, gas remains more significant due to limited domestic flexibility alternatives beyond storage and imports.

Third, **the scale of hourly production swings increases dramatically from 2030 to 2040 as renewable capacity expands**. Germany's total production ranges from 18 to 327 GW by July 2040 – a nearly 20-fold spread –creating enormous challenges for system balancing that require correspondingly massive flexibility.

4.2. Consumption Peak by Technology

This section examines the peak consumption levels for different electricity-consuming technologies. It is important to note that these figures represent the individual maximum consumption for each technology category, not the simultaneous system peak. In practice, these peaks do not occur at the same moment: for example, heat pump demand peaks during cold winter mornings, whilst EV charging (when uncoordinated) peaks in early evening when commuters return home.

The sum of individual technology peaks therefore substantially exceeds the actual simultaneous system peak demand, reflecting the temporal diversity of consumption patterns – a diversity that represents a resource that can be exploited through coordination and flexibility.

4.2.1. Belgium

Figure 14 presents the peak consumption by technology for Belgium across all scenario variants.
In 2030, the sum of individual technology peaks ranges from 25 GW (LOW BAT, DUMB) to 32 GW (HIGH BAT, V2G). The composition reveals the relative importance of different consumption categories: regular power demand (residential, commercial, industrial loads excluding heat pumps and EVs) accounts for 16 GW, heat pumps contribute 5 GW, electric vehicles range from 3 to 6 GW depending on charging behaviour, and lithium-ion batteries range from 1 to 4.5 GW depending on deployment level.

By 2040, the sum of peaks grows substantially, ranging from 36 GW (LOW BAT, DUMB) to 52 GW (HIGH BAT, SMART). Regular power demand rises to 19 GW, reflecting continued electrification beyond transport and heating. Heat pump consumption peaks at 8 GW as the building stock transitions from fossil heating. EV peak consumption ranges from 6 GW (DUMB scenarios) to 14 GW (SMART and V2G scenarios). Battery charging peaks reach 2.6 GW in LOW BAT scenarios and 10.5 GW in HIGH BAT scenarios.

A notable pattern emerges regarding EV peak consumption: smart charging scenarios show higher peak EV consumption than uncoordinated charging scenarios. In 2030, EV peaks are 3 GW in DUMB scenarios but 6 GW in SMART scenarios; in 2040, this gap widens from 6 GW (DUMB) to 14 GW (SMART). This counterintuitive result reflects the nature of optimised charging: when charging is coordinated, the model can concentrate charging activity during periods of abundant renewable generation (midday solar peaks) or low prices, leading to higher instantaneous charging rates than occur under uncoordinated charging where vehicles simply begin charging upon arrival and are constrained by when drivers happen to plug in.

This pattern illustrates the "double-edged sword" of EV flexibility. On one hand, smart charging enables EVs to provide valuable services to the grid by absorbing renewable surpluses. On the other hand, this flexibility manifests as higher peak charging rates during optimal periods. The 3 GW EV peak in 2030 DUMB scenarios represents a burden that occurs at predictable times (evening arrival peaks); the 6 GW peak in 2030 SMART scenarios represents a larger instantaneous load, but one that is deliberately placed during periods when the system can accommodate it. The gap between "burden" and "opportunity" is precisely what smart charging addresses – not by reducing peak EV consumption, but by relocating it to periods where it creates value rather than stress.

4.2.2 Country Comparison

Figure 15 compares peak consumption patterns across Belgium, Germany, France, the Netherlands, and the United Kingdom.

The cross-country comparison reveals substantial differences in both the scale and composition of peak consumption.

Germany operates at a fundamentally different scale. In 2030, the sum of individual peaks ranges from 211 GW (LOW BAT, DUMB) to 312 GW (HIGH BAT, SMART). Regular demand accounts for 129 GW, heat pumps contribute 35 GW, EVs range from 22 to 51 GW, and batteries range from 24 to 96 GW. By 2040, peaks grow to 319–520 GW, with EV peaks reaching 55 GW (DUMB) to 127 GW (SMART) and battery charging reaching 52–181 GW. The enormous scale of German battery charging peaks in HIGH BAT scenarios (up to 181 GW) reflects the massive storage deployment assumed, which can absorb substantial volumes of surplus solar generation during midday peaks.

France shows a distinctive pattern with minimal battery contribution. In 2030, peaks range from 126 to 138 GW, with regular demand at 86 GW, heat pumps at 28 GW, and EVs ranging from 11 to 24 GW. Battery peaks remain negligible (under 1 GW) across all scenarios, reflecting France's limited assumed battery deployment. By 2040, peaks reach 160–207 GW, with EV consumption peaking at 35 GW (DUMB) to 82 GW (SMART). The very modest battery peaks even in HIGH BAT scenarios (under 1 GW) confirm that France's flexibility needs are met primarily through nuclear and hydropower rather than electrochemical storage.

The Netherlands demonstrates particularly high battery peak consumption relative to its size. In 2030, peaks range from 36 to 54 GW, with batteries contributing 5–18 GW depending on deployment level. By 2040, peaks reach 66–126 GW, with battery charging peaks of 17–68 GW. The 68 GW battery charging peak in the 2040 HIGH BAT scenarios is remarkable for a country of the Netherlands' size, reflecting the intensive daily cycling required to manage its solar-dominated generation mix.

The United Kingdom shows wind-driven patterns. In 2030, peaks range from 88 to 133 GW, with regular demand at 55 GW, heat pumps at 9 GW, EVs at 12–27 GW, and batteries at 12–42 GW. By 2040, peaks grow to 158–254 GW. The UK's battery peaks (up to 50 GW in 2040 HIGH BAT) are substantial but lower than the Netherlands relative to system size, reflecting the wind-dominated system's longer-duration variability patterns that are less suited to intensive daily battery cycling.

Comparative insights reveal that smart EV charging increases peak EV consumption across all countries, not just Belgium. This pattern is particularly pronounced in larger markets: German EV peaks more than double from DUMB to SMART scenarios (22 to 51 GW in 2030; 55 to 127 GW in 2040). Similarly, UK EV peaks grow from 12 to 27 GW (2030) and 44 to 102 GW (2040). France shows the largest absolute increase, with 2040 EV peaks rising from 35 GW (DUMB) to 82 GW (SMART) – a 2.3-fold increase.

The implication is clear: network planning must account for smart charging not as a peak reduction strategy but as a peak relocation strategy. Whilst smart charging reduces EV contribution to evening demand peaks (beneficial for system adequacy), it creates new midday charging peaks during periods of renewable abundance. Distribution and transmission networks must be sized to accommodate these new load patterns, even though they occur during periods of lower stress on thermal generation.

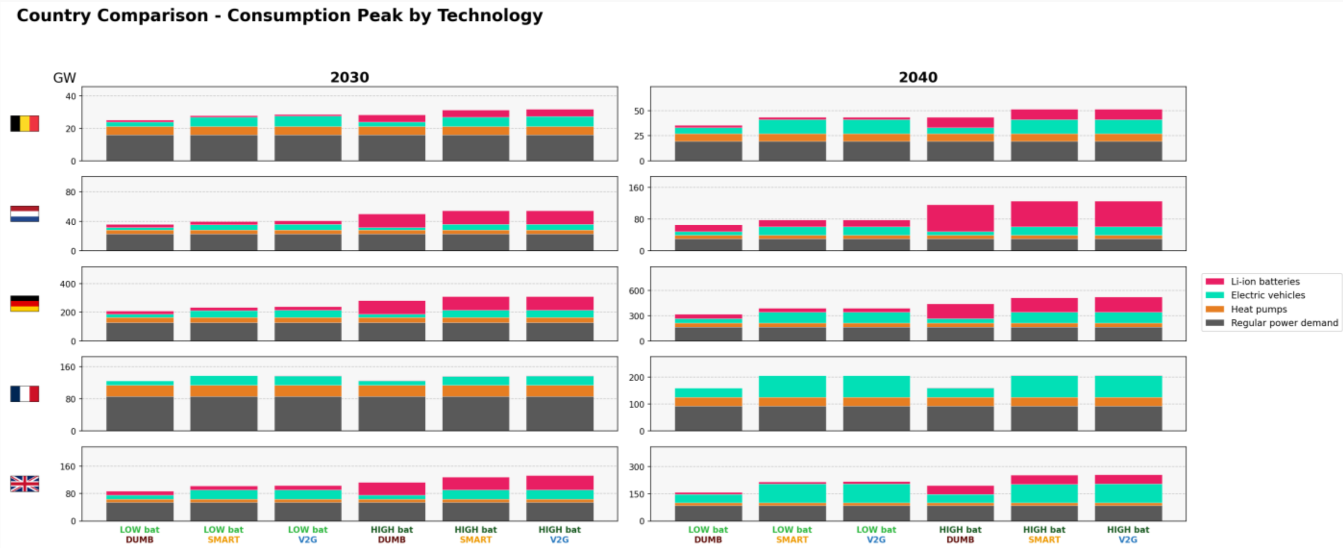


Figure 15: Peak consumption by technology across countries for 2030 and 2040. Values represent individual technology peaks, not simultaneous system peaks.

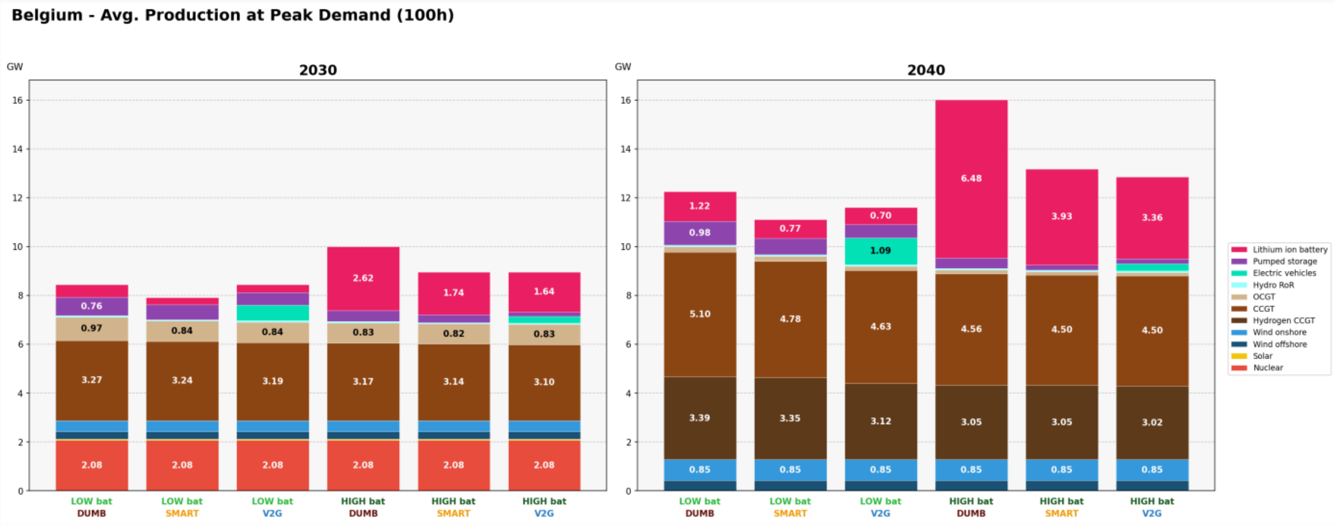


Figure 16: Average electricity production by technology during the 100 hours of highest residual demand in Belgium for 2030 and 2040.

4.3. Average Production at Peak Demand

This section examines which technologies contribute to meeting demand during the most stressed periods of the year. The metric shown is the average production by technology during the 100 hours of highest residual demand (demand minus variable renewable generation). These hours represent periods when the system faces its greatest challenge: high demand coinciding with low wind and solar output. Understanding which resources contribute during these critical hours is essential for assessing system adequacy and the capacity value of different technologies.

4.3.1. Belgium

Figure 16 presents the average production by technology during peak demand hours for Belgium.

In 2030, total average production during peak hours ranges from 8 to 10 GW depending on the scenario. The composition reveals which technologies are called upon when the system is most stressed. Nuclear provides a constant 2 GW – its full capacity, demonstrating its role as firm baseload capacity. Gas-fired generation (CCGT plus OCGT) contributes approximately 4 GW, representing the primary dispatchable resource for managing peak demand. Wind (onshore plus offshore) provides 0.75 GW on average during these hours – substantially below its installed capacity of nearly 10 GW, reflecting that peak demand hours typically coincide with low wind conditions. Solar contributes negligibly (under 0.1 GW), confirming that winter evening peaks drive system stress. Pumped hydro contributes 0.2–0.8 GW, whilst lithium-ion batteries provide 0.3–2.6 GW depending on deployment level.

The role of V2G during peak hours is particularly noteworthy. In the LOW BAT V2G scenario, electric vehicles discharge an average of 0.64 GW during peak demand hours – comparable to pumped hydro's contribution (0.5 GW in the same scenario) and demonstrating EVs' potential as a peak capacity resource. However, this V2G contribution drops substantially in HIGH BAT scenarios: just 0.27 GW when large battery fleets are available. This confirms that **batteries and V2G compete for the same peak-shaving role; when stationary batteries can provide peak support, the marginal value of V2G diminishes**.

A striking observation is that the CCGT contribution remains relatively stable at 3.1–3.3 GW across all 2030 scenarios regardless of flexibility availability. This suggests that **gas turbines remain essential for adequacy even in flexibility-rich systems**. Flexibility resources (batteries, V2G, pumped hydro) reduce the need for OCGT peaking capacity and shift some load away from peak hours, but they do not eliminate the fundamental requirement for firm dispatchable generation. **The 3 GW of CCGT running during peak hours represents capacity that must be available and cannot be fully substituted by storage or demand response.**

By 2040, peak hour production rises to 11–16 GW, reflecting higher overall demand. With nuclear phased out, gas-fired generation (conventional CCGT, hydrogen CCGT, and OCGT) provides 7.5–8.7 GW during peak hours – substantially more than in 2030. Hydrogen CCGT contributes approximately 3 GW, whilst conventional CCGT provides 4.5–5.1 GW. Battery contribution increases substantially: from 0.7 GW (LOW BAT SMART) to 6.5 GW (HIGH BAT DUMB). In HIGH BAT scenarios, batteries become the second-largest contributor to peak hour production after gas-fired generation.

The V2G contribution in 2040 follows a similar pattern to 2030 but at larger scale: 1.1 GW in LOW BAT V2G scenarios, dropping to just 0.3 GW in HIGH BAT V2G scenarios. This 73% reduction confirms the substitution effect observed in 2030. The implication for capacity adequacy planning is clear: **V2G can contribute meaningfully to system adequacy, but its contribution should not be "double-counted" alongside large battery deployments**. In a future with abundant stationary storage, the incremental adequacy value of V2G is modest.

4.3.2. Country Comparison

Figure 17 compares average production during peak demand hours across Belgium, Germany, France, the Netherlands, and the United Kingdom.

Germany

Germany requires the largest absolute contribution during peak hours, reflecting its system size. In 2030, total peak-hour production ranges from 67 to 87 GW. Gas-fired generation (CCGT, OCGT, and hydrogen CCGT) provides 24–32 GW, while wind (despite typically low output during peak hours) still contributes 19–20 GW on average given Germany's enormous installed capacity. Batteries contribute 4–30 GW depending on deployment, and pumped hydro adds 5–9 GW.

V2G in Germany provides meaningful contribution during peak hours: 4.1 GW in the 2030 LOW BAT V2G scenario, rising to 7.1 GW in 2040. However, as in Belgium, this drops substantially in HIGH BAT scenarios (0.3 GW in 2030, 1.3 GW in 2040), confirming that **the substitution effect between batteries and V2G is not Belgium-specific but operates across the European system**.

By 2040, German peak-hour production reaches 83–139 GW. Battery contribution in HIGH BAT scenarios reaches an extraordinary 48–72 GW during peak hours – larger than Belgium's entire installed generation fleet. This demonstrates the scale of flexibility required to manage a system with over 500 GW of variable renewable capacity.

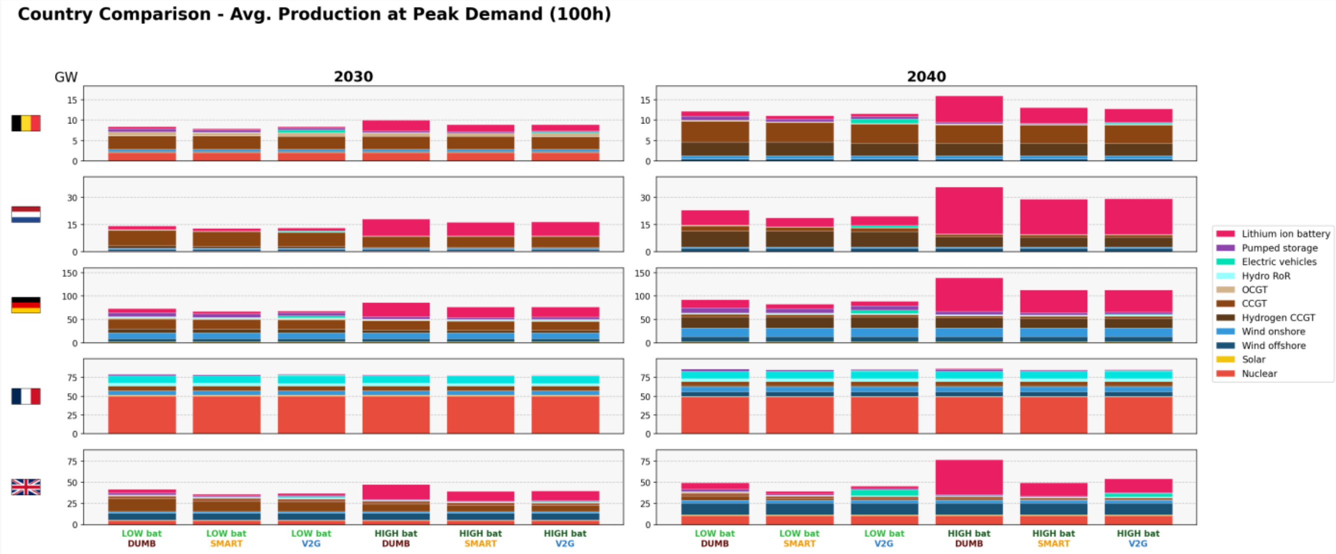


Figure 17: Average electricity production by technology during the 100 hours of highest residual demand across countries for 2030 and 2040.

France

France presents a fundamentally different picture due to its nuclear fleet. In 2030, nuclear provides 51 GW during peak hours – 64% of total peak-hour production (79 GW). Hydropower (reservoir plus run-of-river) contributes 13 GW, demonstrating its essential role in French system adequacy. Gas-fired generation adds 6–7 GW, whilst batteries contribute negligibly (under 0.5 GW even in HIGH BAT scenarios).

The minimal battery contribution during French peak hours is notable: even when battery capacity is available, France's nuclear-hydro combination provides sufficient flexibility that batteries are not needed for peak adequacy. This confirms that France's inherent flexibility reduces the marginal value of additional storage resources.

V2G contributes 0.6–1.3 GW during French peak hours, comparable to Belgium in absolute terms but representing a smaller share of total production. By 2040, the pattern remains similar: nuclear provides 49 GW, hydro adds 13 GW, and batteries contribute under 1 GW even in HIGH BAT scenarios.

France's system adequacy remains anchored in dispatchable nuclear and hydro rather than electrochemical storge.

The Netherlands

The Netherlands shows high battery contribution during peak hours relative to system size. In 2030, batteries provide 1.5–9.4 GW during peak hours (compared to 0.3–2.6 GW in Belgium), reflecting the Netherlands' larger assumed battery deployment and solar-dominated system that requires substantial storage for peak management. Gas-fired generation (CCGT, OCGT, hydrogen CCGT) provides 8–10 GW.

By 2040, Dutch battery contribution during peak hours reaches 5–26 GW in HIGH BAT scenarios – extraordinarily high relative to the country's size. This simply reflects the large battery capacity assumed in these scenarios: when substantial storage is available, it naturally discharges during peak demand periods when prices are highest and the system is most stressed.

V2G in the Netherlands provides 0.6–1.0 GW in LOW BAT scenarios but drops to under 0.1 GW in HIGH BAT scenarios – the most dramatic substitution effect among the countries studied. This suggests **the Dutch system may approach "flexibility saturation" in HIGH BAT scenarios where batteries fully displace V2G's peak contribution**.

United Kingdom

The UK's peak-hour production mix reflects its wind-dominated system. In 2030, wind contributes 10 GW during peak hours despite typically unfavourable conditions, whilst gas-fired generation provides 12–19 GW. Batteries contribute 2–18 GW depending on scenario, and nuclear adds 5 GW.

V2G in the UK provides substantial peak contribution: 1.8 GW in 2030 LOW BAT V2G, rising to 7.1 GW in 2040 LOW BAT V2G – the highest absolute V2G contribution among the countries studied. **This reflects the UK's large EV fleet and its partial insulation from continental flexibility resources via submarine cables**. However, in HIGH BAT scenarios, UK V2G contribution drops to 1.0 GW (2030) and 4.6 GW (2040) – a smaller relative reduction than in other countries, suggesting **the UK system retains more headroom for V2G even when battery capacity is high**.

By 2040, UK peak-hour production reaches 40–77 GW. Nuclear increases to 11 GW (reflecting new build), whilst gas-fired generation provides 3–9 GW. Batteries contribute 3–41 GW depending on scenario, becoming the dominant peak resource in HIGH BAT scenarios.

Comparative Insights

The cross-country analysis reveals consistent patterns. First, **gas-fired generation remains essential for peak adequacy across all countries**, though its contribution varies with the availability of alternative flexibility. The minimum CCGT contribution during peak hours provides a rough indicator of "firm capacity" requirements that storage cannot fully displace.

Second, V2G contribution during peak hours is systematically lower when stationary batteries are abundant. This substitution effect operates across all countries, though its magnitude varies. Belgium and the Netherlands show the largest relative reductions (60–90% decline from LOW BAT to HIGH BAT), whilst the UK shows smaller reductions (40–50%), possibly reflecting its partial isolation from continental flexibility.

Third, **France stands out as the country where batteries provide the least peak contribution, even when deployed**. France's nuclear-hydro flexibility is sufficient for peak management, leaving little value for additional storage during system stress periods. This suggests that optimal battery deployment levels are highly context-dependent: what makes sense for the Netherlands or Germany may not be economically justified in France.

4.4. Electricity prices

4.4.1. Belgium

Electricity prices provide a crucial lens through which to understand the system-wide impacts of flexibility deployment. Prices reflect the marginal cost of meeting demand at each hour, and their evolution across scenarios reveals how flexibility resources reshape market dynamics. This section examines both average price levels and the distribution of prices throughout the year, including the occurrence of extreme price events that signal system stress.

Figure 18 presents average and demand-weighted average electricity prices in Belgium across all scenario variants for 2030 and 2040.

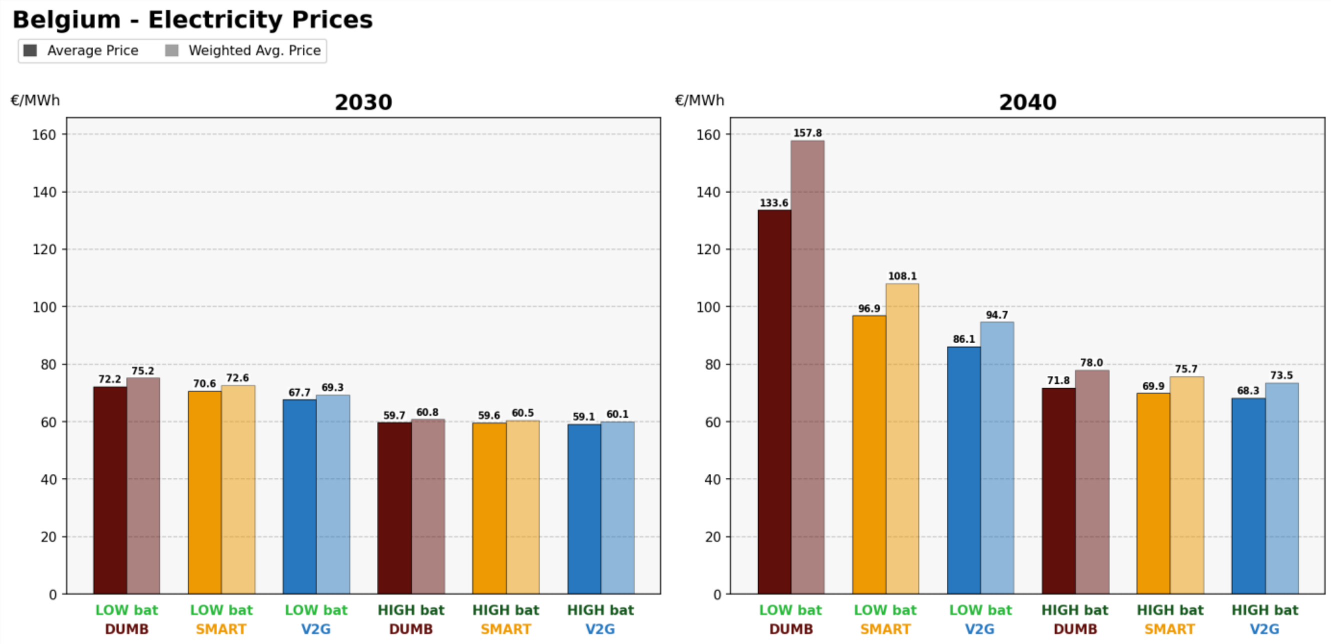


Figure 18: Average and demand-weighted average electricity prices in Belgium for 2030 and 2040. The left bar in each pair shows the simple average hourly price; the right bar shows the consumption-weighted average, reflecting what consumers actually pay on average.

In 2030, average electricity prices fall with increasing flexibility. The simple average price declines from 72.2 €/MWh in the LOW BAT DUMB scenario to 59.1 €/MWh in the HIGH BAT V2G scenario, representing an 18% reduction. Demand-weighted average prices, which reflect what consumers actually pay when their consumption is concentrated during particular hours, show a similar pattern: from 75.2 €/MWh (LOW BAT DUMB) to 60.1 €/MWh (HIGH BAT V2G). This price dampening effect benefits all electricity consumers, reducing costs without requiring any change to the installed generation mix.

The gap between simple and weighted average prices provides insight into price volatility. In the LOW BAT DUMB scenario, the weighted average exceeds the simple average by 3.0 €/MWh, indicating that consumption tends to occur during more expensive hours. As flexibility increases, this gap narrows: in the HIGH BAT V2G scenario, the difference falls to just 1.0 €/MWh. This convergence indicates that **flexibility resources successfully shift consumption away from high-price periods, reducing consumer exposure to peak pricing**.

The impact of stationary battery deployment is particularly pronounced. Moving from LOW BAT to HIGH BAT scenarios reduces average prices by approximately 12–13 €/MWh regardless of EV charging behaviour. In contrast, moving from DUMB to V2G charging within the same battery scenario yields more modest savings of 3–4 €/MWh. This suggests that, in 2030, stationary batteries provide the dominant price-dampening effect, whilst EV flexibility contributes incrementally.

By 2040, the price dynamics become substantially more dramatic. Average prices in the LOW BAT DUMB scenario reach 133.6 €/MWh, nearly double the 2030 level, reflecting the increased system stress from higher renewable penetration and demand growth. Demand-weighted average prices are even more striking: 157.8 €/MWh in LOW BAT DUMB, indicating severe price spikes during peak consumption periods.

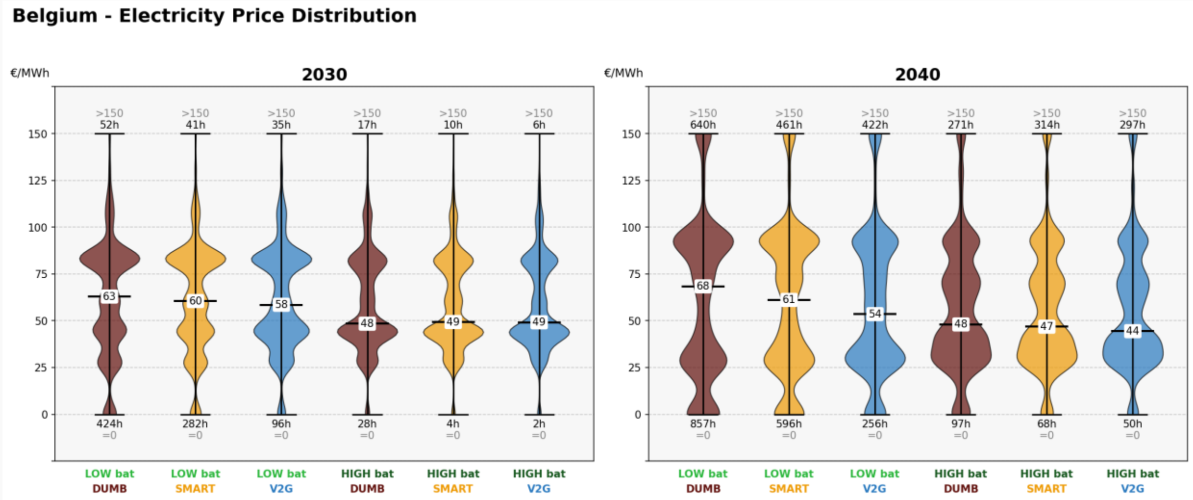


Figure 19: Distribution of hourly electricity prices in Belgium for 2030 and 2040. Violin width indicates the density of prices at each level; black horizontal lines show median prices. Red numbers above indicate hours with prices exceeding 150 €/MWh; green numbers below indicate hours with zero prices. Prices are clipped at 150 €/MWh for visualisation.

Flexibility deployment in 2040 yields correspondingly larger benefits. In the HIGH BAT V2G scenario, average prices fall to 68.3 €/MWh and weighted average prices to 73.5 €/MWh, representing reductions of 49% and 53% respectively compared to LOW BAT DUMB. This more-than-halving of consumer electricity costs illustrates how flexibility can fundamentally reshape electricity economics in a high-renewable future.

Figure 19 presents the distribution of hourly electricity prices through violin plots, providing visibility into the full range of prices experienced throughout the year rather than just averages.

The price distributions reveal patterns that average figures obscure. In 2030, median prices range from 62.9 €/MWh (LOW BAT DUMB) to 48.4 €/MWh (HIGH BAT DUMB), a spread of 14.5 €/MWh.

The HIGH BAT scenarios show notably tighter distributions with lower medians, indicating more stable pricing throughout the year. The difference between mean and median prices is particularly informative: in LOW BAT DUMB, the mean (72.2 €/MWh) substantially exceeds the median (62.9 €/MWh), indicating that high outliers are pulling the average upward. In HIGH BAT V2G, this gap essentially disappears (mean 59.1 €/MWh versus median 49.2 €/MWh), indicating a more symmetric distribution with fewer extreme events.

The occurrence of extreme price hours demonstrates the most dramatic differences across scenarios. In the 2030 LOW BAT DUMB scenario, prices exceed 150 €/MWh during 52 hours of the year (0.6%), with 33 hours exceeding 500 €/MWh and 29 hours reaching the assumed value of lost load at 3,000 €/MWh. These **scarcity pricing events, whilst infrequent, represent genuine periods of system stress where supply barely meets demand**.

Flexibility resources progressively eliminate these extreme events. Smart charging reduces hours above 150 €/MWh to 41 (2030 LOW BAT SMART), whilst V2G further reduces them to 35 hours (2030 LOW BAT V2G).

The most dramatic impact comes from battery deployment: the HIGH BAT DUMB scenario shows only 17 hours above 150 €/MWh, whilst HIGH BAT SMART and V2G scenarios achieve remarkably low figures of 10 and 6 hours respectively. In the HIGH BAT V2G scenario, maximum prices fall to just 150.2 €/MWh; scarcity pricing is essentially eliminated.

The pattern of zero-price hours reveals a complementary dynamic. In the LOW BAT DUMB scenario, 424 hours (4.8%) experience zero or near-zero prices, reflecting periods when renewable generation exceeds what the system can absorb. Smart charging reduces zero-price hours to 282 (3.2%), as EVs absorb some surplus generation. V2G further reduces them to 96 hours (1.1%). In HIGH BAT scenarios, zero-price hours become rare: just 28 hours in HIGH BAT DUMB, 4 hours in HIGH BAT SMART, and only 2 hours in HIGH BAT V2G. **Flexibility resources thus compress the price distribution from both ends, eliminating both scarcity spikes and surplus-driven price collapses**.

By 2040, extreme price events become far more prevalent in low-flexibility scenarios. The LOW BAT DUMB scenario experiences 640 hours (7.3%) with prices exceeding 150 €/MWh, including 287 hours above 500 €/MWh and 238 hours at the 3,000 €/MWh ceiling. Simultaneously, zero-price hours rise to 857 (9.8%), indicating pronounced periods of both surplus and scarcity. This bimodal distribution, with prices clustering at both extremes, characterises an inflexible system struggling to match variable renewable supply with inelastic demand.

Flexibility deployment substantially moderates these extremes. The HIGH BAT V2G scenario reduces hours above 150 €/MWh to 297 (3.4%) and zero-price hours to just 50 (0.6%). However, it is notable that even in the most flexibility-rich 2040 scenario, nearly 300 hours still experience prices above 150 €/MWh, compared to just 6 hours in the equivalent 2030 scenario. This reflects the fundamental increase in system variability as solar PV capacity nearly doubles and nuclear capacity is phased out. Flexibility resources are highly effective at managing this variability, but the underlying challenge grows substantially between 2030 and 2040.

The elimination of extreme price spikes has important implications beyond average cost reduction. For retailers, large consumers, and market participants, price volatility creates substantial risk that must be hedged, often at significant cost. Reducing the frequency and magnitude of price extremes lowers hedging costs and improves financial predictability. **Industrial competitiveness, particularly for energy-intensive industries, improves when electricity costs become more stable and predictable**.

The dampening of price volatility is sometimes characterised as "cannibalising" flexibility value. **By reducing price spreads, flexibility resources erode the arbitrage opportunities that make them profitable**. This self-limiting dynamic is an important consideration for investment: the first flexibility resources deployed capture substantial value from wide price spreads, but subsequent deployments face diminished returns as the spreads they would exploit no longer exist. The difference in median prices between LOW BAT and HIGH BAT scenarios (14.5 €/MWh in 2030, 20.3 €/MWh in 2040) represents both a consumer benefit and a reduction in the revenue available to flexibility providers.

Price compression also has distributional implications that extend beyond flexibility providers. Consumers benefit from lower average costs and reduced exposure to extreme prices. However, merchant generators, including conventional thermal plants, see reduced revenues as scarcity pricing events that previously generated substantial margins become increasingly rare. The system as a whole achieves cost savings, but these savings come at the expense of revenues that would otherwise flow to generation asset owners. This redistribution of value is an important consideration for market design and investment incentives.

4.4.2. Country Comparison

The cross-country comparison of electricity prices reveals how national generation mixes, flexibility deployments, and interconnection patterns produce markedly different price outcomes across European markets. Figure 20 presents average and demand-weighted average electricity prices for Belgium, Germany, France, the Netherlands, and the United Kingdom.

2030 Price Dynamics

In 2030, Continental European countries show broadly similar average price levels in the LOW BAT DUMB baseline scenario: Germany at 74.8 €/MWh, Belgium at 72.2 €/MWh, France at 70.7 €/MWh, and the Netherlands at 67.0 €/MWh. **The United Kingdom stands apart with substantially lower prices at 44.8 €/MWh, reflecting its abundant offshore wind generation that creates persistent surpluses and depresses wholesale prices**.

The relationship between simple and weighted average prices varies instructively across countries. In Belgium, France, and Germany, weighted averages exceed simple averages by 3–6 €/MWh, indicating that consumption tends to concentrate during higher-price periods. The Netherlands shows the opposite pattern: the weighted average (60.8 €/MWh) falls below the simple average (67.0 €/MWh). **This reflects the Dutch system's extremely high incidence of zero-price hours (1,413 hours, or 16.1% of the year) driven by solar surpluses**; Dutch consumers effectively benefit from this abundance as their flexible loads (including smart-charging EVs and heat pumps) concentrate consumption during low-price periods.

The United Kingdom similarly shows weighted averages below simple averages (41.9 versus 44.8 €/MWh), reflecting an even more extreme pattern: 2,187 hours (25.0% of the year) with zero or near-zero prices due to wind surpluses.

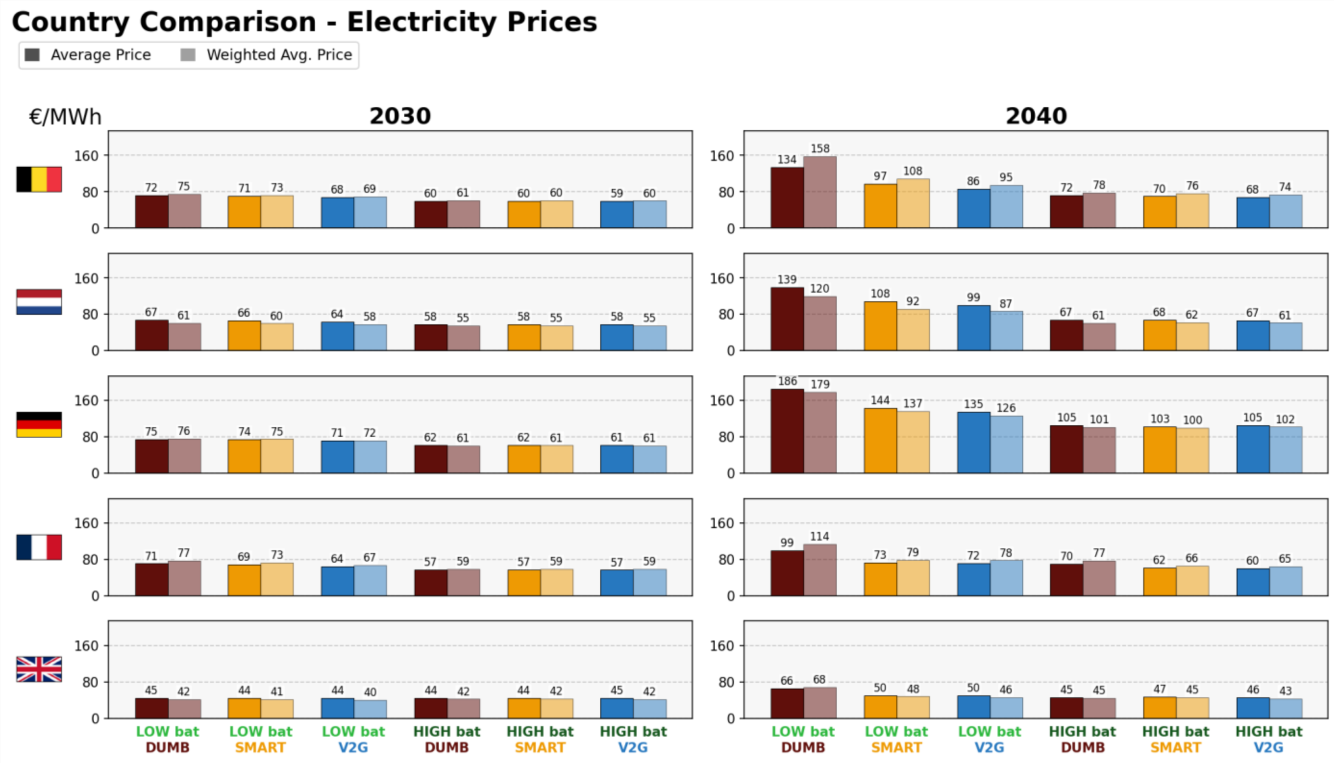


Figure 20: Average and demand-weighted average electricity prices across countries for 2030 and 2040. Left bars show simple averages; right bars show consumption-weighted averages.

Maximum prices in the UK reach only 128.3 €/MWh in 2030, with zero hours exceeding 150 €/MWh. The UK system in 2030 effectively experiences no scarcity events whatsoever, representing a fundamentally different market regime from the continental countries.

Flexibility deployment produces consistent price reductions across all countries, though the magnitude varies. Moving from LOW BAT DUMB to HIGH BAT V2G reduces average prices by 13.1 €/MWh in Belgium (72.2 to 59.1 €/MWh), 13.5 €/MWh in Germany (74.8 to 61.3 €/MWh), 14.1 €/MWh in France (70.7 to 56.6 €/MWh), and 9.3 €/MWh in the Netherlands (67.0 to 57.7 €/MWh). **The UK shows negligible price reduction** (44.8 to 44.6 €/MWh) **because prices are already low and scarcity events are absent; there is little headroom for flexibility to compress further**.

2040 Price Dynamics

By 2040, the price landscape transforms dramatically, with much larger spreads between countries and scenarios. In the LOW BAT DUMB scenario, Germany experiences the highest prices at 185.9 €/MWh average (178.8 €/MWh weighted), followed by the Netherlands at 138.8 €/MWh, Belgium at 133.6 €/MWh (157.8 €/MWh weighted), and France at 99.1 €/MWh. The United Kingdom maintains the lowest prices at 65.5 €/MWh despite experiencing its first scarcity events (374 hours above 150 €/MWh).

The extreme price hours metric reveals the severity of system stress in low-flexibility futures. Germany experiences 835 hours (9.5%) with prices exceeding 150 €/MWh, including 494 hours above 500 €/MWh. The Netherlands shows 662 extreme hours, Belgium 640 hours, and France 430 hours. Even the UK, which avoided scarcity entirely in 2030, experiences 374 extreme hours by 2040 as demand growth outpaces the absorption capacity of its wind-dominated system.

Germany's exceptionally high 2040 prices in low-flexibility scenarios reflect the combination of massive renewable capacity (366 GW solar, 159 GW onshore wind) and insufficient flexibility to absorb the resulting variability. The standard deviation of German prices reaches 543 €/MWh in the LOW BAT DUMB scenario, indicating enormous volatility that makes financial planning extremely difficult for market participants.

Flexibility deployment in 2040 yields correspondingly larger benefits. Moving from LOW BAT DUMB to HIGH BAT V2G reduces German average prices from 185.9 to 105.2 €/MWh (a 43% reduction), Dutch prices from 138.8 to 66.8 €/MWh (52% reduction), Belgian prices from 133.6 to 68.3 €/MWh (49% reduction), and French prices from 99.1 to 60.5 €/MWh (39% reduction). The UK shows more modest reduction from 65.5 to 46.3 €/MWh (29%).

France exhibits notably lower price volatility than other continental countries. In the 2040 LOW BAT DUMB scenario, French average prices (99.1 €/MWh) are 47% lower than German prices and 26% lower than Belgian prices. **This reflects France's nuclear-hydro system providing inherent flexibility that other countries must source from batteries and EVs**. The standard deviation of French prices (298 €/MWh) is substantially lower than Germany's (543 €/MWh), indicating a more stable market environment.

Price Distribution Analysis

Figure 21 presents violin plots showing the full distribution of hourly prices across countries, revealing how flexibility deployment fundamentally transforms price distributions from volatile, fat-tailed shapes into compact, nearly symmetric forms.

The Transformation from Bimodal to Unimodal Distributions

The most striking observation from the violin plots is not the shape of any single distribution, but rather how dramatically shapes transform as flexibility increases. In low-flexibility scenarios, most countries exhibit bimodal or fat-tailed distributions with substantial density at both price extremes. As flexibility deployment increases, these distributions compress into tight, unimodal shapes concentrated more around the median.

This compression occurs because flexibility resources eliminate both types of extreme events simultaneously. **Batteries and smart-charging EVs absorb surplus generation during low-price periods** (reducing zero-price hours) **and inject power during scarcity periods** (reducing extreme high prices). **The result is convergence toward the "middle ground" of moderate prices.**

Interpreting Violin Width as a Risk Metric

The width of violin plots at different price levels provides intuitive insight into market risk. A wide violin at high prices indicates substantial probability of expensive hours that consumers must hedge against. A wide bulge at zero prices indicates periods when renewable generators earn nothing and face curtailment risk.

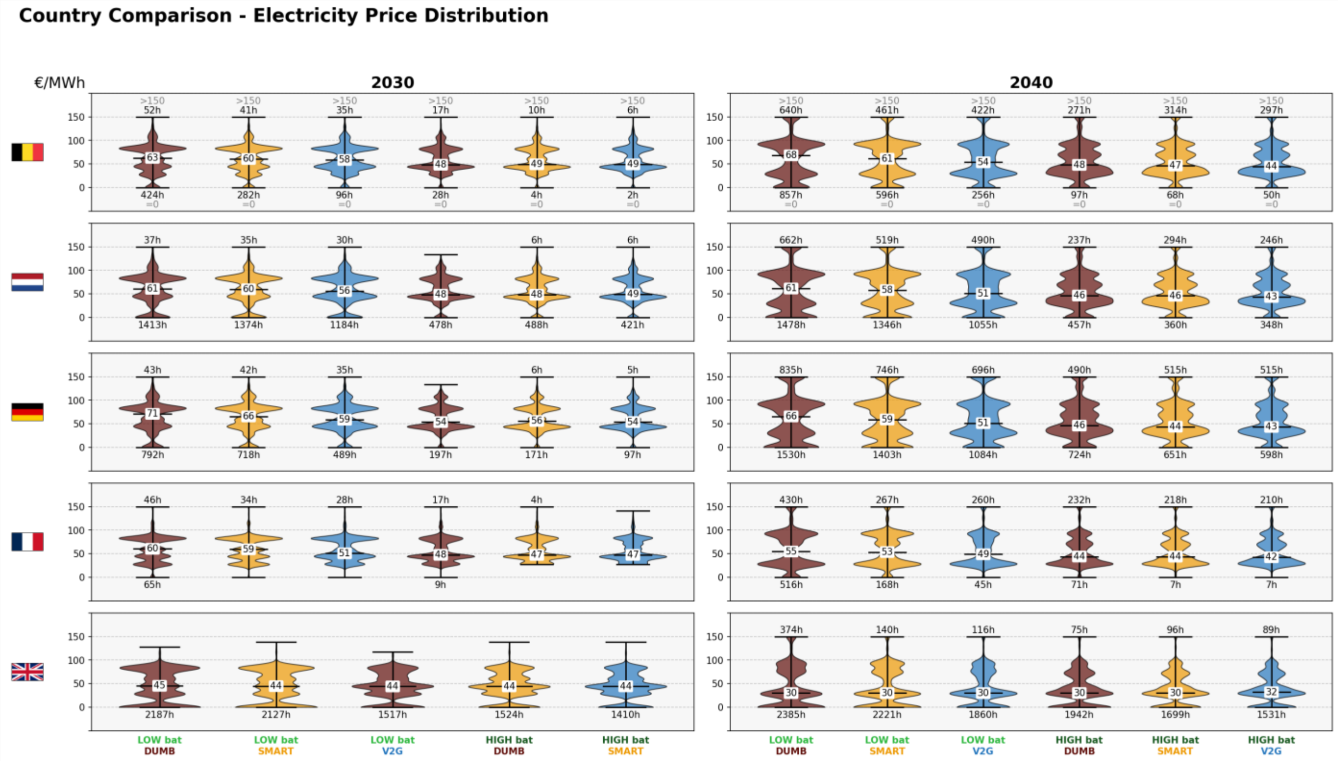


Figure 21: Distribution of hourly electricity prices across countries for 2030 and 2040. Violin width indicates price density; black lines show median prices. Numbers above indicate hours exceeding 150 €/MWh; numbers below indicate zero-price hours.

The transformation from wide to narrow violins thus represents risk reduction for all market participants. Consumers benefit from reduced probability of extreme bills; generators benefit from more predictable revenues; retailers benefit from reduced hedging requirements; and system operators benefit from reduced balancing challenges. The visual compression of violin shapes across scenarios represents this "de-risking" of electricity markets through flexibility deployment.

The comparison of violin widths across countries also reveals relative market stability. France's consistently narrow violins (even in LOW BAT scenarios) indicate inherently lower risk, whilst Germany's wide violins (even in HIGH BAT scenarios by 2040) indicate persistent volatility that flexibility only partially addresses.

Belgium's intermediate violin widths reflect its position as an interconnected market influenced by both stable (French nuclear) and volatile (German renewable) neighbours.

4.5. Stationary Battery Operation and Economics

Having examined electricity prices in detail, this section turns to a holistic assessment of stationary battery performance in terms of operational utilisation, economic returns, and cycling intensity. The analysis synthesises the interplay between battery deployment levels, EV charging behaviour, and the resulting market dynamics that together determine whether battery investments appear economically viable.

4.5.1. Belgium

4.5.1.1. Battery Production and Consumption

Figure 22 presents the annual electricity production, losses, and consumption of the lithium-ion battery fleet in Belgium across all scenario variants.

Battery throughput varies dramatically with both deployment level and EV charging behaviour. In 2030, the LOW BAT fleet (roughly 1.1 GW power capacity, 2.2 GWh energy capacity) produces between 0.7 and 0.9 TWh annually, while the HIGH BAT fleet (4.5 GW, 27 GWh) produces between 4.5 and 5.9 TWh. This roughly six-to-sevenfold increase in production, despite only a fourfold increase in power capacity, reflects the longer storage duration of HIGH BAT systems (6 hours versus 2 hours), which enables capture of a broader range of arbitrage opportunities.

The impact of EV flexibility on battery utilisation is pronounced and consistent. In the LOW BAT scenarios, battery production falls from 0.9 TWh (DUMB) to 0.7 TWh (SMART and V2G), representing a 22% reduction as EV flexibility increases. The HIGH BAT scenarios exhibit an even sharper decline: from 5.9 TWh (DUMB) to 4.7 TWh (SMART) and 4.5 TWh (V2G), a 24% reduction.

This pattern confirms the competitive relationship between EV flexibility and stationary batteries identified in earlier sections: **when EVs provide load-shifting services, they directly displace battery cycling that would otherwise occur**.

By 2040, battery throughput increases substantially in absolute terms, reflecting both higher installed capacities (2.6 GW LOW BAT, 10.5 GW HIGH BAT) and greater system flexibility needs driven by the near-doubling of solar PV capacity. LOW BAT production ranges from roughly 1.5 to 2 TWh, whilst HIGH BAT production reaches 9 to 13 TWh. The proportional impact of EV flexibility remains similar: **production falls by approximately 28-29% from DUMB to V2G scenarios** in both battery configurations.

The energy losses visible in the figure, representing the difference between consumption and production, amount to approximately 8-9% of throughput across all scenarios. This round-trip efficiency penalty is an inherent characteristic of electrochemical storage. **In the 2040 HIGH BAT DUMB scenario, losses exceed 1 TWh**, representing energy that is consumed but not recovered. **By contrast, smart EV charging that merely shifts load timing triggers no additional energy losses, giving it an inherent efficiency advantage** for load-shifting applications. This distinction has implications for how policymakers should weigh the merits of stationary storage versus demand-side flexibility: unidirectional smart charging achieves similar load-shifting outcomes without the efficiency penalty.

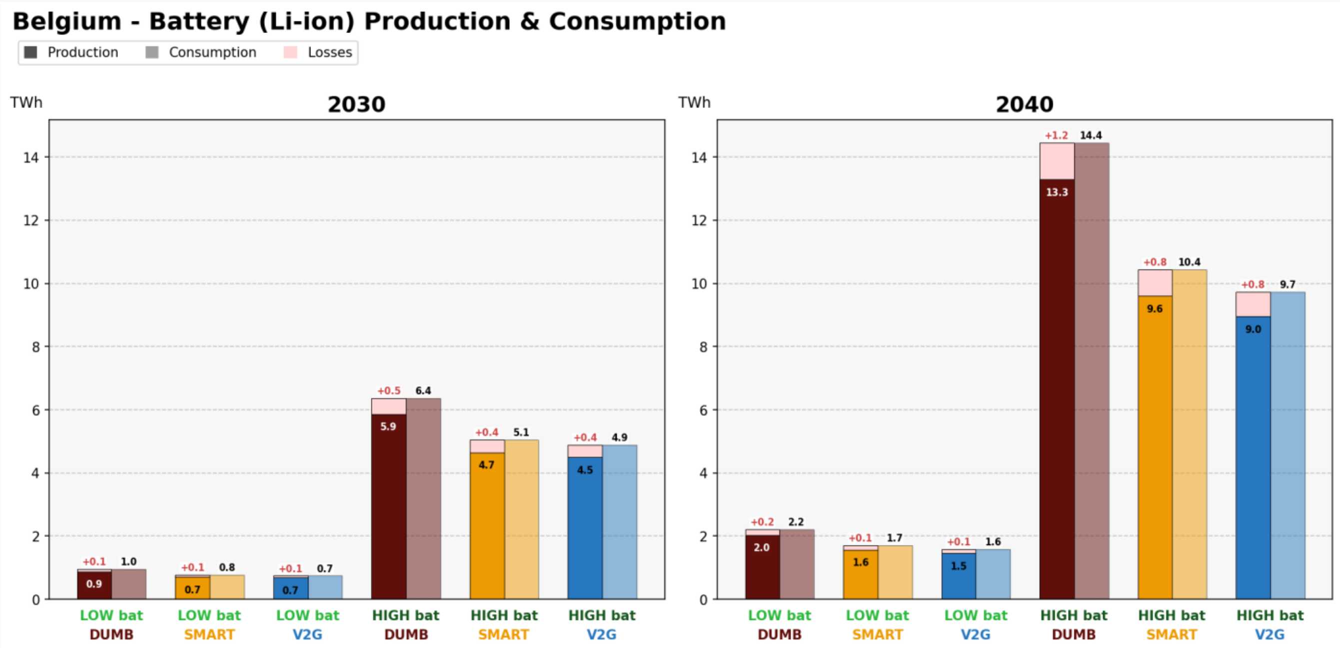


Figure 22: Lithium-ion battery production, losses, and consumption in Belgium for 2030 and 2040. Left bars show production (discharge) plus round-trip losses; right bars show consumption (charging). The difference between consumption and production represents energy losses.

4.5.1.2. Battery Economics

Figure 23 presents the economic performance of the battery fleet in terms of total costs, revenues, and operating surplus.

The economics of battery operation reveal striking patterns that fundamentally challenge simplistic assumptions about storage profitability. In 2030, the LOW BAT fleet earns a surplus of €58 million in the DUMB scenario, representing robust returns from price arbitrage in a system with limited flexibility. However, this surplus declines sharply as EV flexibility increases: to €42 million under SMART charging (27% reduction) and just €28 million under V2G (52% reduction). **The same installed battery capacity, facing the same underlying system conditions, earns half as much when competing against flexible EVs**.

The HIGH BAT scenarios reveal a second critical dynamic: diminishing returns to scale. Despite quadrupling power capacity and increasing energy capacity twelvefold, the HIGH BAT fleet in 2030 earns only marginally more total surplus than the LOW BAT fleet in comparable EV scenarios. In the DUMB scenario, HIGH BAT surplus reaches €62 million versus €58 million for LOW BAT, a mere 8% increase despite the massive capacity expansion. Under V2G, the picture is even starker: HIGH BAT surplus of €32 million represents only a €4 million increase over LOW BAT surplus of €28 million. **Adding 3.4 GW of battery power capacity generates essentially zero marginal value in a V2G-rich system**.

To understand these dynamics more clearly, Figure 24 presents the same economic data normalised per GW of installed capacity.

The per-GW analysis reveals the severity of value erosion. In 2030, LOW BAT batteries earn €51 million per GW in the DUMB scenario, falling to €37 million per GW (SMART) and €25 million per GW (V2G). HIGH BAT batteries, facing the compressed price spreads that large storage deployment creates, earn substantially less per unit: €14 million per GW (DUMB), €9 million per GW (SMART), and just €7 million per GW (V2G). This represents an 86% reduction in per-GW profitability between the most favourable scenario (LOW BAT DUMB) and the least favourable (HIGH BAT V2G).

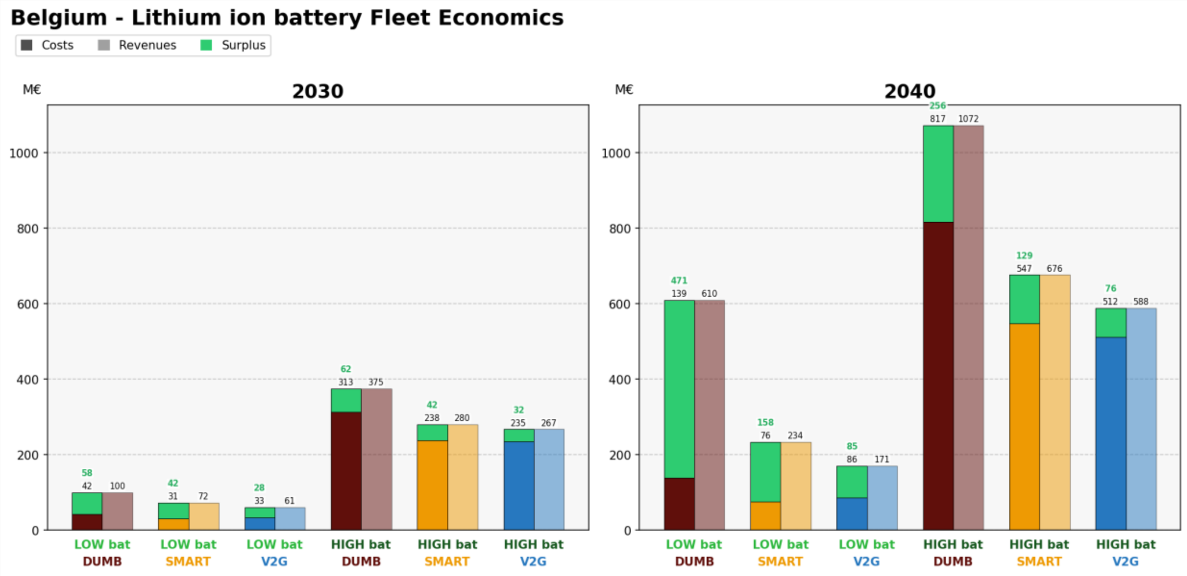


Figure 23: Li-ion battery fleet costs, revenues, and surplus in Belgium for 2030/2040. Costs include charging costs and operational expenses; revenues derive from electricity sales. Surplus represents the operating margin available to cover capital costs.

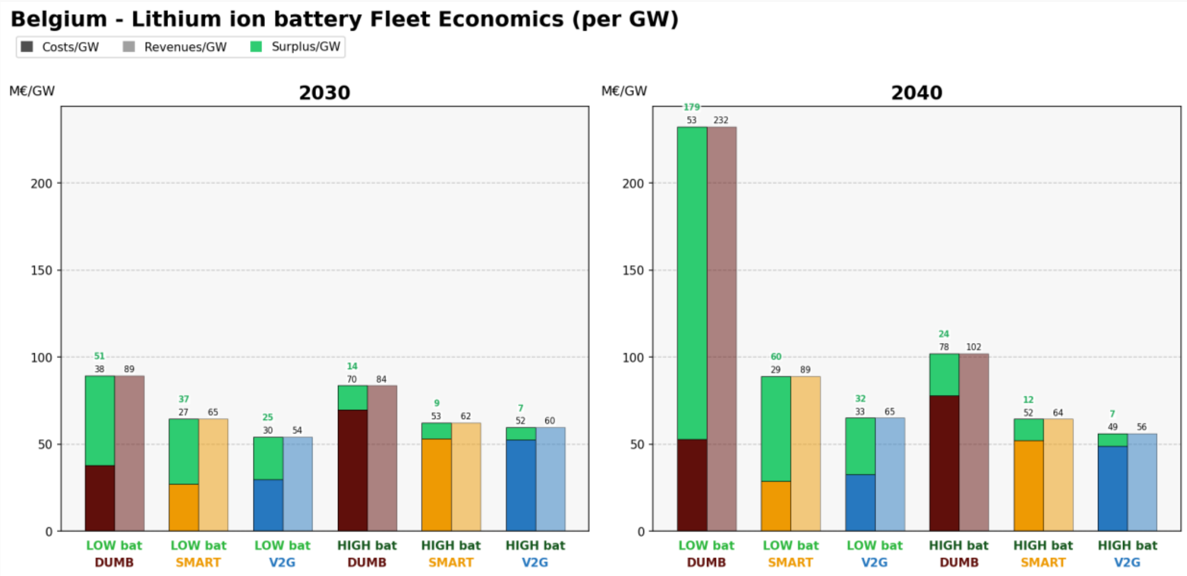


Figure 24: Lithium-ion battery fleet economics per GW of installed capacity in Belgium for 2030/2040. Normalisation enables comparison across scenarios with different deployment levels.

The mechanism underlying this value erosion is the price compression documented in Section 4.5. Batteries earn revenues by buying electricity during low-price periods and selling during high-price periods. As battery deployment increases, this arbitrage activity itself compresses the price spreads that make it profitable. **The first GW of batteries captures substantial value from wide spreads; subsequent GW face progressively narrower spreads and correspondingly lower returns.** When V2G-capable EVs perform similar arbitrage functions, they further compress available spreads, leaving even less value for stationary batteries to capture.

By 2040, absolute surplus figures increase substantially due to the larger system and more pronounced price volatility in baseline scenarios. LOW BAT surplus ranges from €85 million (V2G) to €471 million (DUMB), whilst HIGH BAT surplus ranges from €76 million (V2G) to €256 million (DUMB). However, the per-GW analysis reveals that the underlying profitability challenge persists. LOW BAT batteries in 2040 earn €179 million per GW (DUMB), reflecting the extreme price volatility documented in Section 4.4, but this falls to just €32 million per GW under V2G. HIGH BAT per-GW surplus ranges from €24 million (DUMB) to €7 million (V2G), remarkably similar to the 2030 figures despite the larger system.

Contextualising Surplus Against Capital Costs

The surplus figures presented above represent operating margins: revenues from electricity sales minus charging and operational costs. **To assess whether these margins could support battery investment, it is instructive to compare them against indicative capital costs**, even if such comparison must be approached with considerable caution.

Several important caveats apply to any such analysis. First, the simulations are not designed as precise prediction machines for electricity prices; they employ marginal cost pricing within a simplified market representation that abstracts from many real-world complexities. Second, real-world batteries engage in "value stacking" across multiple revenue streams (capacity markets, ancillary services, reserve provision, imbalance market participation) that the wholesale energy arbitrage captured here represents only partially. Third, any capital cost estimate involves substantial uncertainty: battery costs have declined rapidly and projections for 2030 and 2040 vary widely across sources. Fourth, treating the entire fleet as if constructed instantaneously at a single cost point ignores the reality of gradual deployment at evolving costs. Fifth, installed battery costs include not only cell costs but also power electronics, balance of plant, grid connection, and developer margins, all of which vary by project. These limitations mean the following analysis should be understood as indicative rather than definitive, intended to provide rough context rather than precise investment appraisal.

With these caveats established, consider illustrative capital cost assumptions. For 2030, fully installed “total” battery costs might plausibly range from €200-250 per kWh; for 2040, continued cost declines could yield €100-150 per kWh. Annualising these costs over a 15-year asset life at a 7% discount rate produces approximate annual capital recovery requirements.

For LOW BAT systems with 2-hour duration, 1 GW of power capacity corresponds to 2 GWh of energy capacity. At €225/kWh (a mid-range 2030 estimate), this implies roughly €450 million in capital cost per GW, or approximately €50 million per GW annually when annualised. For 2040, at €125/kWh, the corresponding figures would be roughly €250 million total and €27 million annually per GW.

Comparing these indicative figures to the simulation results suggests that 2-hour batteries in LOW BAT scenarios might approach economic viability from energy arbitrage alone under certain conditions. The 2030 DUMB scenario surplus of €51 million per GW roughly matches the illustrative annualised capital cost of €50 million, suggesting approximate breakeven. However, as EV flexibility increases, the surplus falls below this threshold: €37 million per GW (SMART) and €25 million per GW (V2G) would leave shortfalls of €13-25 million annually. By 2040, the picture shifts: the extreme price volatility in the DUMB scenario produces surplus far exceeding capital requirements (€179 million versus €27 million), whilst even V2G scenarios (€32 million) exceed the lower 2040 capital threshold.

For HIGH BAT systems with 6-hour duration, the economics appear substantially more challenging. The longer duration means threefold higher energy capacity per GW of power, and correspondingly threefold higher capital costs: roughly €1,350 million per GW in 2030 (€150 million annualised) and €750 million in 2040 (€82 million annualised). Against these figures, the simulation surplus of €7-24 million per GW falls dramatically short. Even the most favourable HIGH BAT scenario (2040 DUMB at €24 million per GW) covers less than 30% of the indicative annualised capital cost.

This stark difference between short and long-duration battery economics reflects a double penalty for longer duration systems. Not only does the additional energy capacity require proportionally more capital investment, but the larger aggregate storage capacity compresses price spreads more severely, reducing the per-GW operating surplus. The result is that 6-hour batteries face higher costs and lower revenues per unit of power capacity compared to 2-hour systems.

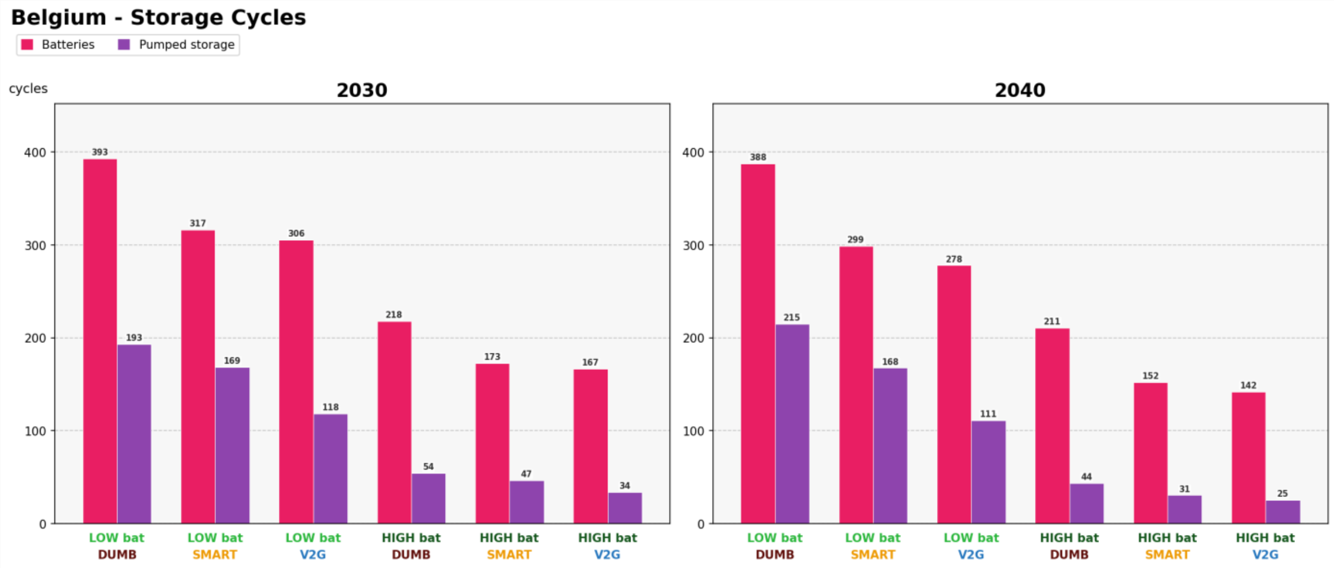


Figure 25: Annual equivalent full discharge cycles for lithium-ion batteries and pumped hydro storage in Belgium for 2030 and 2040. Higher cycle counts indicate more intensive utilisation; lower counts indicate underutilisation or reserve capacity.

Interpreting These Comparisons

These rough comparisons, despite their many limitations, suggest several tentative observations. First, **the viability of battery investment from energy arbitrage alone appears highly sensitive to both the flexibility landscape** (how much competing flexibility exists) **and battery duration** (shorter duration appears more favourable). Second, **long-duration batteries as modelled in the HIGH BAT scenarios would likely require substantial additional revenue streams beyond energy arbitrage to justify investment**; capacity payments, ancillary service revenues, or other value streams would need to bridge a significant gap. Third, **the competitive effect of EV flexibility is economically significant: in 2030, it appears sufficient to push short-duration batteries from approximate breakeven toward clear unprofitability**.

It bears repeating that these observations rest on numerous simplifying assumptions and should not be interpreted as definitive statements about battery investment viability. Real-world investment decisions involve far more detailed analysis of specific project economics, revenue stacking opportunities, financing structures, and risk assessments. The value of this indicative comparison lies not in its precision but in highlighting the orders of magnitude involved and the sensitivity of battery economics to the broader flexibility landscape. Even if the specific numbers shift with different assumptions, the qualitative insight remains: **battery profitability from arbitrage alone is scenario-dependent, duration-sensitive, and vulnerable to competition from alternative flexibility sources**.

Investment Risk and Uncertainty

The scenario dependence of battery economics creates substantial investment risk. An investor deciding today whether to deploy battery capacity faces uncertainty about which future materialises. If EV flexibility develops slowly (closer to DUMB scenarios), batteries could earn attractive returns. If smart charging and V2G become widespread (V2G scenarios), the same batteries could struggle to recover their capital costs. This uncertainty is compounded by the fact that battery deployment and EV flexibility are likely to evolve together: an investor cannot simply assume a favourable scenario will persist.

The contrast between absolute and per-GW economics adds a further layer of complexity. Absolute surplus figures might suggest that larger battery fleets in 2040 are economically attractive. However, the per-GW figures reveal that the larger fleet size is primarily compensating for lower unit profitability. Whether such deployments materialise depends on whether capital costs decline sufficiently to match the reduced per-unit returns, and whether additional revenue streams (beyond energy arbitrage) can bridge any remaining gap.

4.5.1.3. Storage Cycling Intensity

Figure 25 presents the annual cycle counts for lithium-ion batteries and pumped hydro storage, providing insight into how intensively storage assets are utilised across scenarios.

Cycle counts decline dramatically with increasing flexibility availability. In 2030, LOW BAT batteries complete nearly 400 cycles annually in the DUMB scenario, falling to around 310 cycles under SMART and V2G charging. HIGH BAT batteries exhibit even lower cycling: roughly 220 cycles (DUMB), 170 cycles (SMART), and 165 cycles (V2G). The pattern persists in 2040, with HIGH BAT V2G batteries completing only about 140 cycles annually.

Battery Lifetime Considerations

To interpret these cycling figures, it is helpful to consider typical battery lifetime characteristics, recognising that these vary by chemistry and continue to evolve with technological progress.

Contemporary utility-scale lithium-ion batteries are typically rated for 3,000-6,000 equivalent full cycles before reaching end-of-life, usually defined as degradation to 70-80% of original capacity. Lithium iron phosphate (LFP) chemistries tend toward the higher end of this range (sometimes exceeding 6,000 cycles), whilst nickel-manganese-cobalt (NMC) chemistries typically fall toward the lower end. By 2030 and 2040, continued improvements in cell chemistry, thermal management, and manufacturing quality are expected to push cycle life ratings higher, though the precise trajectory remains uncertain.

However, cycle life represents only one constraint on battery longevity. Batteries also experience "calendar aging": degradation that occurs over time regardless of how intensively the battery is cycled. Chemical processes within the cells proceed continuously, even when the battery sits idle. Calendar life for current utility-scale systems is typically estimated at 15-20 years, and whilst future systems may achieve longer calendar life, this remains a binding constraint that limits how long batteries can operate regardless of cycling intensity.

The interaction between cycle aging and calendar aging determines which constraint binds in practice. In scenarios with intensive cycling (approaching 400 cycles annually), cycle life is likely the limiting factor. A battery completing 400 cycles per year would exhaust a 4,000-cycle rating in roughly 10 years, likely before calendar aging becomes critical. Such intensive use maximises energy throughput but accelerates wear.

In scenarios with modest cycling (around 150 cycles annually), the arithmetic of cycle life would suggest extraordinarily long operational life: a 4,000-cycle battery at 150 cycles per year would theoretically last over 25 years. However, calendar aging intervenes well before this point. A battery installed in 2030 would likely reach end-of-life by 2045-2050 due to calendar degradation, regardless of having "unused" cycle capacity remaining. The reduced cycling extends battery life only up to the calendar aging ceiling, not beyond it.

Implications for Battery Economics and Utilisation

These lifetime dynamics have nuanced implications for battery economics. In high-cycling scenarios (LOW BAT DUMB), batteries are intensively utilised and may require replacement after 10-12 years. The higher annual revenues documented in Section 4.5.1 must cover capital costs over this shorter period, but the batteries fully exploit their cycle capacity. In low-cycling scenarios (HIGH BAT V2G), batteries cycle gently and could theoretically operate for 15-20 years before calendar aging forces retirement. The lower annual revenues documented earlier would accrue over a longer period, partially offsetting the per-year shortfall, though this extended life comes with its own uncertainties (technology obsolescence, evolving market conditions, degradation of other system components).

The **reduced cycling in high-flexibility scenarios also indicates substantial idle capacity**. A battery completing 150 cycles per year, when designed for daily cycling, operates at roughly 40% of its potential throughput. The remaining 60% represents capacity that is available but not needed because other resources (EVs, interconnections, flexible thermal generation) are already providing equivalent services. **This "stranded flexibility" represents potential value that is not being captured due to competition from other resources**.

Pumped Hydro: A Shifting Role

Pumped hydro storage exhibits even more dramatic cycling reductions than batteries. In 2030, pumped hydro completes roughly 190 cycles in the LOW BAT DUMB scenario but only about 35 cycles under HIGH BAT V2G, an 82% reduction. By 2040 HIGH BAT V2G, pumped hydro cycling falls to just 25 cycles annually.

This dramatic decline suggests a fundamental shift in pumped hydro's operational role. At nearly 400 cycles annually (as observed in some LOW BAT scenarios), pumped hydro operates in a daily arbitrage mode: charging overnight or during midday solar peaks, discharging during morning and evening demand peaks. At 25-35 cycles annually, the operational pattern shifts toward weekly or even longer-duration storage: absorbing extended periods of renewable surplus and discharging during prolonged low-wind, low-solar periods.

Belgium's pumped hydro capacity (1.3 GW at Coo-Trois-Ponts) appears increasingly marginalised for daily balancing as battery and EV flexibility grow. However, its large reservoir capacity (approximately 5 GWh) provides value for longer-duration applications that short-duration batteries cannot replicate. The very low cycling in flexibility-rich scenarios may thus represent not obsolescence but role transformation: from high-frequency daily arbitrage toward lower-frequency but longer-duration balancing services. This distinction is important for assessing pumped hydro's continued value in a system with abundant short-duration flexibility.

4.5.1.4. Synthesis: The Battery Investment Landscape

System Benefits versus Private Returns

A fundamental tension emerges between the system-wide benefits that batteries provide and the private returns that investors can capture. Batteries deliver clear value to the electricity system: they enable renewable integration, reduce price volatility, lower average consumer costs, and reduce emissions by displacing gas-fired generation. These benefits, documented throughout earlier sections of this report, provide a strong rationale for policy support of storage deployment.

However, **the same market dynamics that create system benefits erode private returns**. Price compression benefits consumers but narrows the arbitrage spreads that make battery investment profitable. Competition from EV flexibility further reduces the value pool available to stationary storage. The result is a potential divergence between system-optimal and privately-viable deployment levels: the system might benefit from substantial battery capacity, but investors may be unable to capture sufficient returns to justify deployment without additional revenue streams or policy support.

The Flexibility Competition Dynamic

The competitive relationship between stationary batteries and EV flexibility emerges as a central finding. As EV charging becomes smarter and V2G capability spreads, EVs absorb an increasing share of the arbitrage opportunities that would otherwise accrue to batteries. This competition reduces battery utilisation (fewer cycles), compresses available price spreads (lower per-cycle margins), and ultimately erodes battery profitability.

The magnitude of this effect is substantial. Moving from DUMB to V2G scenarios reduces battery surplus per GW by roughly 50% in 2030 and 60-80% in 2040. **For batteries operating near the margin of viability, this reduction can represent the difference between a sound investment and a stranded asset**.

Importantly, this competitive dynamic operates regardless of whether batteries are "better" or "worse" than EVs at providing flexibility services. Both resources target similar arbitrage opportunities (charging during low-price periods, discharging or reducing load during high-price periods), and deployment of either resource compresses the value available to both. The finding is not that EVs will "win" and batteries will "lose", but rather that neither resource can be evaluated in isolation; their economics are fundamentally interdependent.

Investment Timing and Coordination

The sequencing of flexibility deployment matters considerably. **Early batteries, deployed before competing flexibility materialises, can capture substantial value from wide price spreads**. Later entrants face compressed spreads created by earlier deployment of both batteries and flexible EVs. **This first-mover advantage creates incentives for early deployment, potentially leading to a "rush" that could overshoot economically efficient levels**.

Coordination between battery and EV flexibility deployment thus becomes important for efficient resource allocation. If both resources target the same arbitrage opportunities, and deployment of either resource erodes value for the other, planning that considers their interaction may yield better outcomes than independent optimisation of each. This observation does not imply that central planning is necessary or desirable, but it does suggest that market signals alone may produce outcomes that differ from system-optimal configurations.

4.5.2. Country Comparison

The cross-country comparison reveals how national generation mixes and flexibility landscapes shape battery economics and utilisation. This section highlights the most significant cross-country differences and their implications.

France

The TYNDP scenarios assume negligible battery capacity (just 0.2-0.9 GW across all scenarios, compared to 10-207 GW in neighbouring countries). France's nuclear-hydro system provides sufficient inherent flexibility that large-scale battery deployment is simply not anticipated. The limited batteries that exist cycle intensively and earn reasonable per-GW returns, but the fleet is too small to merit detailed analysis.

The Netherlands

The Netherlands exhibits the opposite pattern. Its solar-dominated generation mix creates pronounced daily flexibility needs perfectly suited to battery cycling. Dutch batteries in HIGH BAT scenarios produce 22-52 TWh annually, substantially exceeding Belgium despite similar geographic scale. The assumed battery capacity in the Netherlands reaches 69 GW by 2040 HIGH BAT, reflecting the intensive storage requirements of a solar-heavy system.

However, this intensive deployment comes with economic consequences. Per-GW surplus in Dutch HIGH BAT scenarios falls to just €6-18 million, among the lowest values observed. The very large assumed battery fleet compresses price spreads severely, suggesting the Dutch system may approach "battery saturation" in these scenarios.

Germany

In the German context of much higher scale, throughput in HIGH BAT scenarios reaches 52-138 TWh annually, volumes comparable to the total electricity consumption of smaller European countries. The assumed battery capacity of 207 GW in 2040 HIGH BAT represents an extraordinary deployment that would transform European flexibility markets.

Per-GW economics in Germany follow the familiar pattern of declining returns with scale. In 2030 HIGH BAT scenarios, German batteries earn just €5-7 million per GW, insufficient to cover capital costs from arbitrage alone. By 2040, higher price volatility improves returns to €30-38 million per GW in HIGH BAT scenarios, though still below the indicative thresholds discussed for Belgium. The German results suggest that even massive battery deployment may not eliminate arbitrage opportunities entirely, as the scale of German renewable variability creates persistent flexibility needs.

United Kingdom

The UK's wind-dominated system creates distinct battery dynamics. Batteries earn lower per-GW surplus than continental countries in most scenarios: €10-20 million per GW in LOW BAT scenarios versus €35-53 million on the continent. This reflects the UK's already-low wholesale prices (documented in Section 4.4) driven by abundant offshore wind, which compress the arbitrage spreads available to batteries.

UK battery cycling is also lower than solar-dominated systems, reflecting wind's longer-duration variability patterns. Daily solar peaks create predictable arbitrage opportunities well-suited to battery cycling; multi-day wind patterns require different operational strategies. This distinction suggests that **optimal battery duration and operating strategy may differ between solar-dominated and wind-dominated systems**.

Universal Patterns

Despite these national differences, several patterns emerge consistently across all countries (Figure 26):

First, per-GW profitability declines with increasing flexibility from both batteries and EVs. Moving from LOW BAT DUMB to HIGH BAT V2G reduces per-GW surplus by 70-90% across all countries. This cannibalisation effect is not Belgium-specific but operates throughout the interconnected European system.

Second, the economic viability challenges identified for Belgium apply broadly. Long-duration batteries in HIGH BAT scenarios earn per-GW surpluses well below indicative capital cost thresholds across all countries.

Third, the competitive relationship between batteries and EVs is universal. V2G scenarios consistently show lower battery utilisation and profitability than DUMB scenarios,

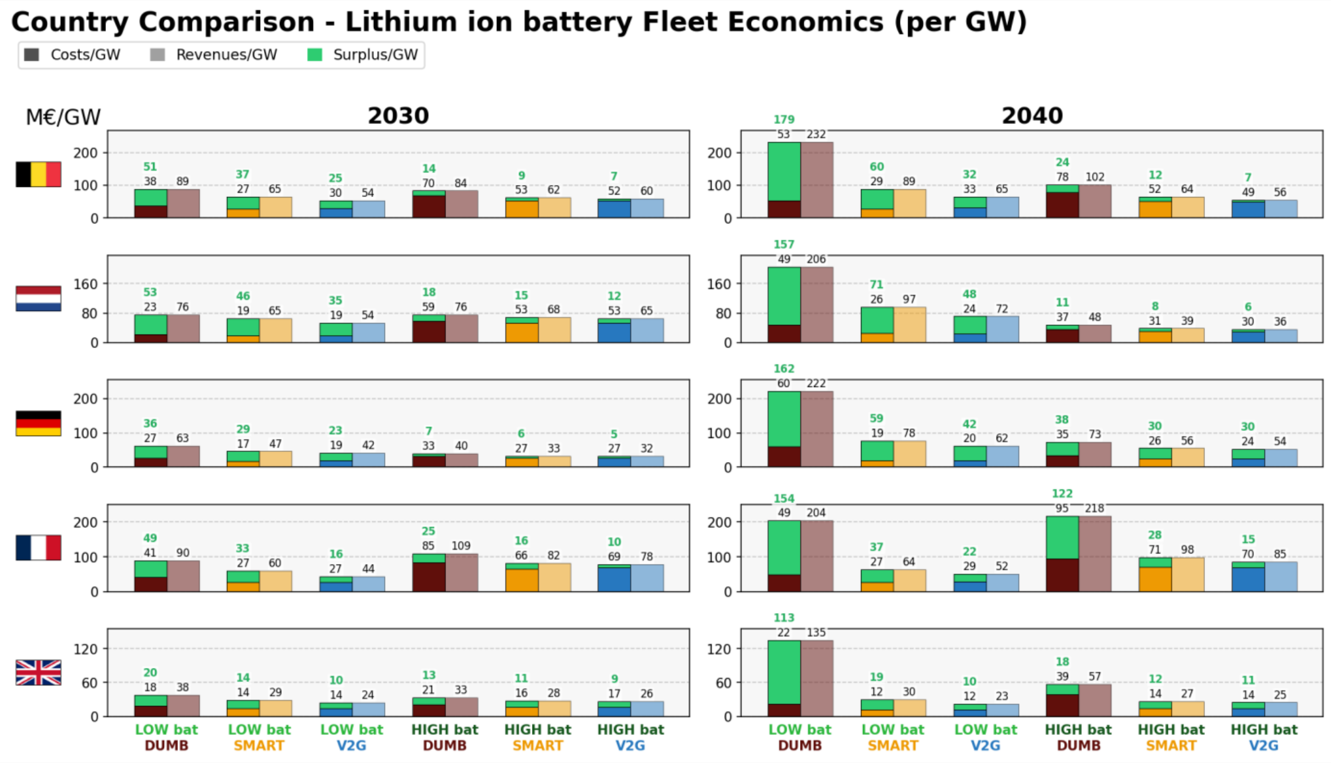


Figure 26: Lithium-ion battery fleet economics per GW of installed capacity across countries for 2030 and 2040. Per-GW normalisation enables meaningful comparison despite vastly different fleet sizes.

confirming that flexibility resources compete for overlapping value pools regardless of national context.

The cross-country comparison thus reinforces the Belgian findings. Battery economics are highly context-dependent, but the fundamental dynamics of value erosion, diminishing returns, and flexibility competition operate across the European system.

4.6. Electric Vehicle Production and Consumption

4.6.1. Belgium

This section examines the electricity flows associated with the Belgian electric vehicle fleet: the consumption required for charging and, in V2G scenarios, the production (discharge back to the grid) that provides flexibility services.

These flows represent the direct interface between the EV fleet and the electricity system, and their magnitude reveals how EV flexibility is actually utilised under different system configurations.

Figure 27 presents annual EV electricity consumption and V2G production across all scenario variants.

Baseline Consumption

In the DUMB charging scenarios, which assume uncontrolled charging without optimisation, EV consumption reaches 3.9 TWh in 2030 and 8.5 TWh in 2040. These figures represent the fundamental electricity demand from vehicle electrification: roughly a doubling over the decade as the EV fleet expands. This baseline consumption is identical across LOW BAT and

HIGH BAT scenarios within each charging behaviour, confirming that stationary battery deployment does not affect how much electricity EVs consume when charging is uncontrolled.

Smart Charging Effects

Moving from DUMB to SMART charging increases apparent consumption: from 3.9 to 4.2 TWh in 2030, and from 8.5 to 9.1 TWh in 2040. This increase of approximately 7% may initially appear counterintuitive, as smart charging is intended to optimise rather than increase consumption.

The explanation lies in the model's optimisation logic: smart charging enables EVs to charge preferentially during low-price periods, which typically coincide with high renewable generation.

By shifting consumption into these periods, EVs absorb renewable generation that might otherwise be curtailed, increasing their apparent consumption whilst simultaneously reducing system curtailment.

This insight highlights an often-overlooked benefit of smart charging: even without bidirectional capability, optimised charging timing enables EVs to act as a "sponge" for renewable surpluses, improving system-wide renewable utilisation without requiring any additional hardware beyond timing optimisation.

V2G Production and Consumption

The V2G scenarios reveal substantially different patterns. In the 2030 LOW BAT V2G scenario, EVs consume 6.4 TWh and produce 2.1 TWh, yielding net consumption of approximately 4.3 TWh.

The gross consumption exceeds DUMB and SMART scenarios because V2G-capable vehicles both charge more (to have energy available for discharge) and discharge back to the grid. The 2.1 TWh of V2G production represents active participation in electricity markets: EVs discharging during high-price periods to capture arbitrage value.

By 2040, V2G activity scales substantially in LOW BAT scenarios: consumption reaches 12.8 TWh and production 3.4 TWh, yielding net consumption of roughly 9.4 TWh. The growth in V2G production (from 2.1 to 3.4 TWh, a 63% increase) reflects both the expanded EV fleet and the increased price volatility documented in Section 4.4, which creates more profitable arbitrage opportunities.

The Substitution Effect: V2G and Stationary Batteries

The most striking pattern in the data concerns the **dramatic reduction in V2G activity when stationary batteries are abundant**. In the 2030 LOW BAT V2G scenario, V2G production reaches 2.1 TWh; in the equivalent HIGH BAT V2G scenario, it falls to just 0.7 TWh, a 65% reduction. The pattern is even more pronounced in 2040: V2G production declines from 3.4 TWh (LOW BAT) to 0.9 TWh (HIGH BAT), a 72% reduction.

This substitution effect has been observed throughout this report in various forms: V2G contribution during peak demand hours (Section 4.3), battery cycling intensity (Section 4.5), and flexibility contribution (Section 4.9). The mechanism is now clearly visible in the raw production figures: **when large stationary battery fleets are deployed, they absorb the arbitrage opportunities that V2G would otherwise capture**. EVs and batteries compete for the same temporal value pools, and when batteries are abundant, V2G activity is substantially displaced.

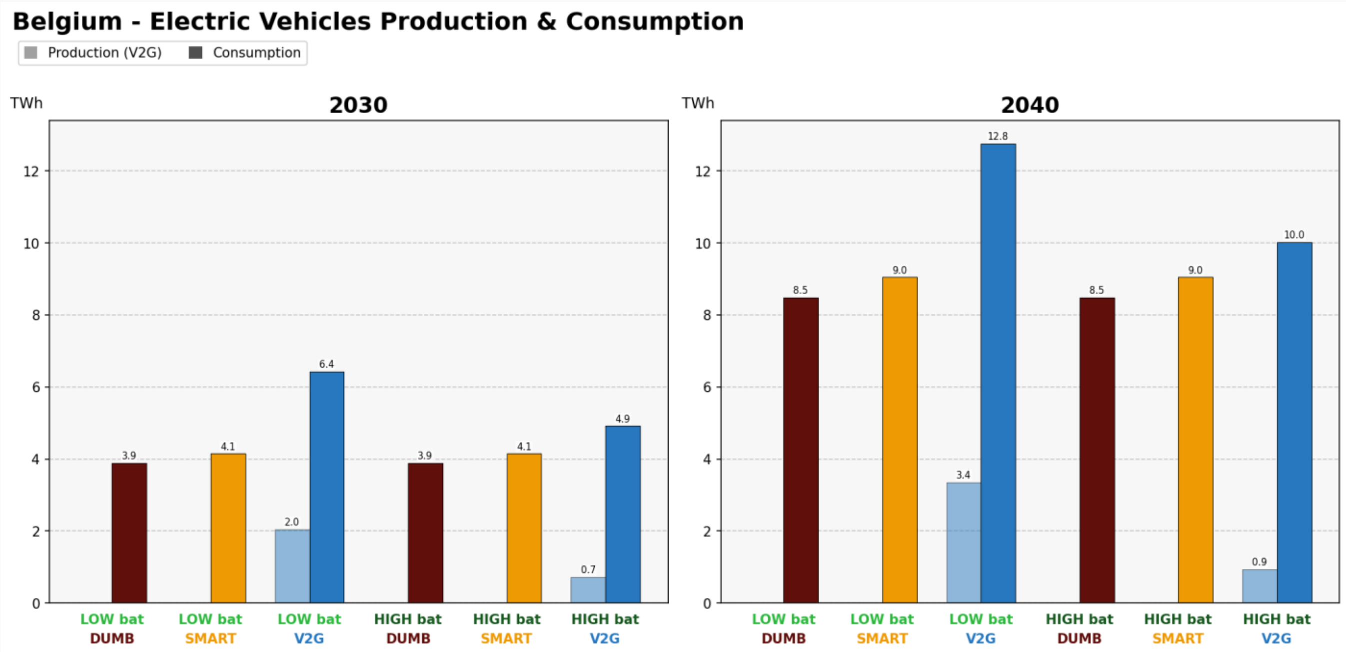


Figure 27: Electric vehicle electricity consumption and V2G production in Belgium for 2030 and 2040. Left bars show V2G discharge (production); right bars show charging consumption. V2G production is zero in DUMB and SMART scenarios by definition.

Implications for V2G Business Cases

These findings have significant implications for the economics of V2G deployment. The value proposition for V2G, which requires additional hardware (bidirectional chargers, more sophisticated battery management systems) and imposes additional wear on vehicle batteries, depends on there being sufficient arbitrage opportunities to justify these costs. In a future with abundant stationary storage, as represented by the HIGH BAT scenarios, the reduction in V2G utilisation of 65–72% suggests correspondingly reduced revenue opportunities.

The business case for V2G is thus highly contingent on the broader flexibility landscape. In flexibility-scarce futures (LOW BAT scenarios), V2G provides substantial value and intensive utilisation that could justify investment in bidirectional infrastructure. In flexibility-rich futures (HIGH BAT scenarios), the incremental value of V2G capability diminishes substantially. Investors and policymakers should recognise this conditionality when evaluating V2G deployment strategies.

By contrast, unidirectional smart charging provides meaningful flexibility benefits (documented in earlier sections) without the hardware cost and battery degradation concerns associated with V2G. The consumption increase from DUMB to SMART scenarios represents this "low-hanging fruit" of EV flexibility: substantial system benefits achieved through timing optimisation alone. This observation suggests that prioritising widespread smart charging deployment may deliver better value than focusing exclusively on the more technologically demanding V2G capability.

4.6.2. Country Comparison

The cross-country comparison reveals how national characteristics shape EV flexibility utilisation. Figure 28 presents EV consumption and V2G production across Belgium, Germany, France, the Netherlands, and the United Kingdom.

V2G Utilisation Patterns

The United Kingdom exhibits the highest absolute V2G production: 25 TWh in 2030 LOW BAT V2G, rising to 75 TWh in 2040. These figures substantially exceed Belgium's 2–3 TWh. The UK's high V2G utilisation reflects its combination of a large EV fleet, ambitious offshore wind targets that create pronounced variability, and island system characteristics that amplify the value of domestic flexibility resources. **With limited interconnection capacity relative to its system size, the UK cannot rely on cross-border flows to the same extent as continental countries, making domestic flexibility more valuable**.

Germany shows the second-highest absolute V2G production: 20 TWh in 2030 LOW BAT V2G, reaching 61 TWh by 2040. The German figures reflect the enormous EV fleet and the extreme renewable variability that characterises Germany's energy transition. However, relative to fleet size, German V2G utilisation is lower than the UK's, suggesting that Germany's continental interconnections and larger market provide alternative flexibility that partially substitutes for V2G.

France exhibits notably lower V2G utilisation despite its substantial EV fleet: 7 TWh in 2030 LOW BAT V2G, rising to 12 TWh in 2040. This pattern reflects the inherent flexibility provided by France's nuclear-hydro system, which reduces the marginal value of additional EV flexibility. **When firm dispatchable capacity and reservoir hydropower already provide substantial balancing capability, the incremental value of V2G is diminished**.

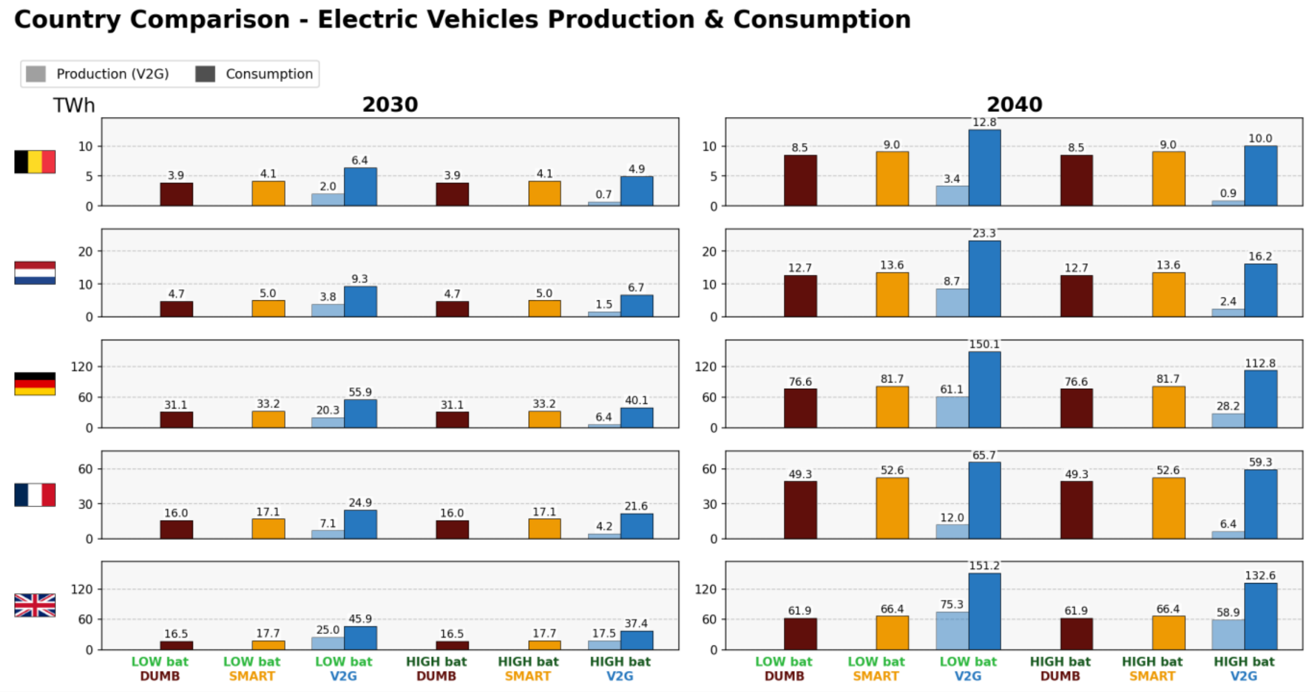


Figure 28: Electric vehicle electricity consumption and V2G production across countries for 2030 and 2040. Left bars show V2G discharge; right bars show charging consumption.

The Netherlands shows particularly high V2G utilisation relative to fleet size: 3.8 TWh in 2030 LOW BAT V2G (comparable to Belgian consumption of 3.9 TWh), rising to 8.7 TWh in 2040. **The Dutch system's solar-heavy generation mix creates pronounced daily flexibility needs that align well with V2G operating patterns**. The daily cycle of solar surplus at midday and demand peaks in evening hours creates regular arbitrage opportunities ideally suited to vehicle battery cycling.

Universal Substitution Effect

The substitution effect observed in Belgium operates consistently across all countries. Moving from LOW BAT to HIGH BAT V2G scenarios reduces V2G production by:

- Belgium: 65% (2030), 72% (2040)
- Netherlands: 60% (2030), 72% (2040)
- Germany: 68% (2030), 54% (2040)
- France: 41% (2030), 47% (2040)
- United Kingdom: 30% (2030), 22% (2040)

The magnitude of substitution varies instructively. Belgium and the Netherlands show the largest reductions, reflecting their smaller system sizes where battery deployment creates more concentrated impacts on flexibility value. France shows intermediate reductions, consistent with its already-abundant flexibility that limits both the baseline V2G opportunity and the incremental impact of batteries. The UK shows the smallest relative reduction, suggesting its island characteristics and wind-dominated variability retain value for V2G even when battery capacity is high.

Comparative Insights

Several patterns emerge from the cross-country analysis. First, **V2G utilisation is highest in systems with pronounced variability and limited alternative flexibility**. The UK's wind-dominated, partially-isolated system creates ideal conditions for V2G; France's flexible nuclear-hydro system creates less favourable conditions.

Second, **the substitution between V2G and stationary batteries is not Belgium-specific** but operates throughout the European system. This confirms that the competitive relationship between these flexibility resources is a fundamental characteristic of electricity markets, not an artefact of Belgian conditions.

Third, **smart charging without V2G** (visible in the consumption increases from DUMB to SMART scenarios) **provides consistent benefits across all countries**. The typical consumption increase of 6–7% in SMART scenarios represents renewable absorption that improves system efficiency regardless of national context.

Fourth, **absolute V2G volumes in flexibility-scarce scenarios (LOW BAT) highlight the scale of potential grid interaction**. UK V2G production of 75 TWh by 2040 would represent a substantial portion of UK electricity demand being cycled through vehicle batteries. **Whether** such **intensive utilisation is practical, given battery degradation concerns and consumer acceptance, remains an open question** that the purely technical optimisation in these simulations does not address.

Policymakers in all countries should recognise that V2G deployment strategies cannot be evaluated in isolation from assumptions about stationary battery deployment, and vice versa. The flexibility landscape is inherently integrated.

4.7. Nuclear Production, Capacity Factor, and Economics

4.7.1. Belgium

Nuclear power in Belgium presents a distinct analytical case within this report. The TYNDP scenarios assume 2 GW of nuclear capacity in 2030, reflecting the planned lifetime extensions of the Doel 4 and Tihange 3 reactors. By 2040, nuclear capacity is assumed to be zero, with these units having reached end of life. This section therefore focuses exclusively on 2030, examining how nuclear operation and economics are influenced by the broader flexibility landscape.

Production and Capacity Factor

Figure 29 presents nuclear production in Belgium across all scenario variants.

A counterintuitive pattern emerges from the data: nuclear production increases as flexibility deployment rises. In the LOW BAT DUMB scenario, nuclear produces 13.1 TWh annually. This rises progressively through SMART (13.3 TWh) and V2G (13.7 TWh) scenarios. The HIGH BAT scenarios show even higher output: 13.9 TWh (DUMB), 14.0 TWh (SMART), and 14.1 TWh (V2G). The difference between the least flexible scenario (LOW BAT DUMB) and the most flexible scenario (HIGH BAT V2G) represents an increase of roughly 1 TWh, or 7%.

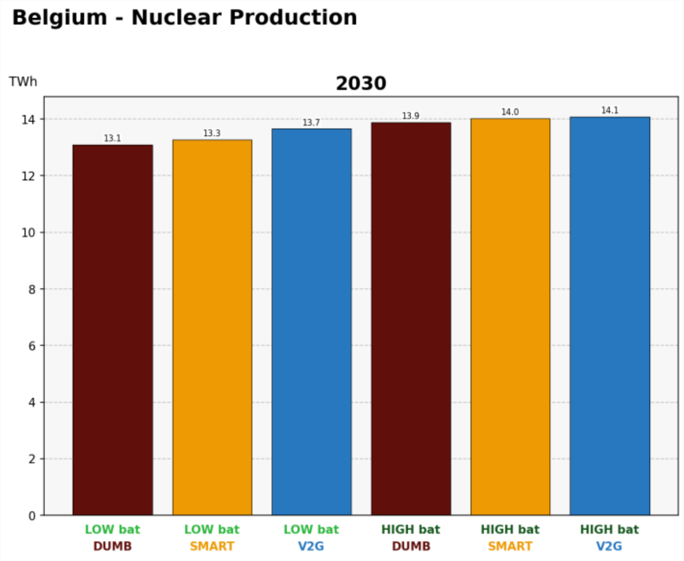


Figure 29: Annual electricity production from nuclear plants in Belgium for 2030 and 2040 across all scenario variants.

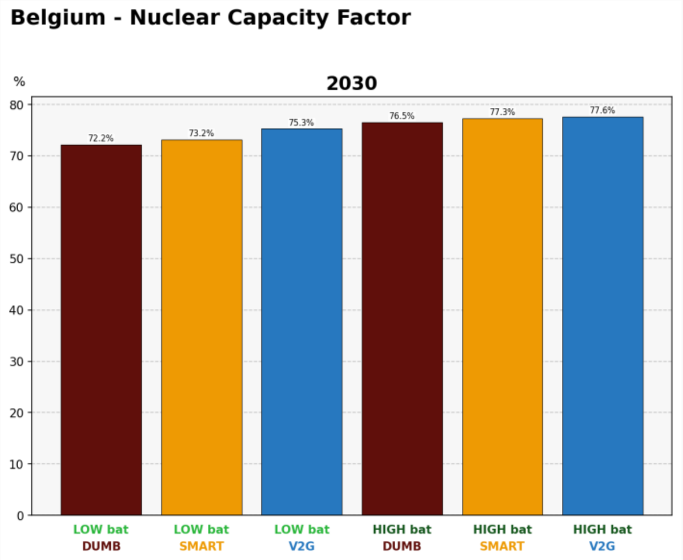


Figure 30: Nuclear capacity factor in Belgium for 2030. Capacity factor represents actual production divided by maximum possible production if plants operated continuously at full output.

Nuclear capacity factors range from 72% in LOW BAT DUMB to 78% in HIGH BAT V2G, a span of 5 percentage points. The difference of approximately 500 operating hours represents a meaningful shift in plant utilisation.

Figure 30 presents capacity factors, which reveal this pattern more clearly.

The Mechanism: Flexibility Insulates Nuclear from Cycling Pressure

The positive relationship between flexibility deployment and nuclear utilisation reflects an important operational dynamic. In systems with limited flexibility, nuclear plants face pressure to reduce output during periods of high renewable generation. When solar production peaks at midday or wind output surges during favourable weather, demand for dispatchable generation falls. If insufficient flexibility exists to absorb this surplus, the model reduces nuclear output rather than curtailing zero-marginal-cost renewables.

Flexibility resources alter this calculus. Batteries and smart-charging EVs absorb renewable surpluses by charging during low-price periods. This absorption reduces the need for nuclear to cycle down, enabling more stable baseload operation. The 7% increase in nuclear production between LOW BAT DUMB and HIGH BAT V2G scenarios represents output that would otherwise have been foregone due to cycling requirements.

This finding has practical implications for the Belgian nuclear extensions. Doel 4 and Tihange 3 will operate in a system with substantially more flexibility resources than the Belgian nuclear fleet has historically experienced. Whilst the plants were designed decades ago for traditional baseload operation, the surrounding system will have evolved considerably. The simulation results suggest this evolution is beneficial for nuclear operation: higher flexibility enables more stable output patterns, potentially reducing the operational stress associated with frequent ramping.

It should be noted, however, that hourly dispatch models of this type do not capture all dimensions of nuclear operational constraints. Real nuclear plants face technical limits on ramping rates, minimum output levels, and the number of cycles that can be performed without additional maintenance. The model assumes these constraints can be managed within the hourly dispatch framework. In practice, very rapid or frequent cycling could impose costs not reflected in the simulation results.

Economic Dynamics

Figure 31 presents nuclear fleet economics in Belgium.

Despite higher production in flexibility-rich scenarios, nuclear revenues decline with increasing flexibility deployment. In LOW BAT DUMB, nuclear revenues reach €1,116 million; in HIGH BAT V2G, they fall to €907 million, a reduction of 19%. Operating surplus (revenues minus variable costs) declines even more sharply: from €758 million (LOW BAT DUMB) to €522 million (HIGH BAT V2G), a 31% reduction.

This apparent paradox, where higher output yields lower revenues, reflects the price compression documented in Section 4.4. Flexibility resources reduce wholesale electricity prices, particularly during the high-price periods when nuclear earns its largest margins. The nuclear plants produce more TWh, but each TWh commands a lower average price. The net effect is reduced total revenue despite increased output.

Belgian nuclear capacity earns a surplus of €365 million/GW in LOW BAT DUMB, falling to €252 million/GW in HIGH BAT V2G. For context, these are operating surpluses from energy market revenues only, needed to cover the costs of lifetime extension refurbishments for the Belgian units.

Whether these surplus levels are "sufficient" depends on the details of the cost allocation framework for the Belgian extensions. If the extension costs are treated as sunk (having already been committed through policy decisions), even the reduced surplus in HIGH BAT V2G scenarios represents positive returns on marginal operation. However, **if future decisions must justify extension costs on a commercial basis, the sensitivity of nuclear economics to the flexibility landscape becomes a relevant consideration**.

The Asymmetric Relationship Between Nuclear and Flexibility

The interaction between nuclear power and flexibility resources is fundamentally asymmetric. Flexibility resources (batteries, EVs) can reduce the operational pressure on nuclear plants by absorbing renewable variability that would otherwise require nuclear cycling. However, nuclear cannot reciprocally provide the short-duration flexibility services that batteries and EVs excel at. Nuclear plants ramp slowly, face minimum output constraints, and are optimised for continuous rather than intermittent operation.

This asymmetry has strategic implications. From a nuclear operator's perspective, flexibility deployment by others is beneficial operationally (enabling more stable output) but detrimental economically (compressing prices and revenues). From a system planning perspective, flexibility and nuclear serve complementary roles: nuclear provides firm low-carbon generation, whilst flexibility manages the temporal mismatches between variable renewable supply and demand.

The Belgian context illustrates this complementarity clearly. The planned nuclear extensions provide approximately 2 GW of firm capacity that remains available regardless of weather conditions or time of day. This capacity contributes reliably during the peak demand periods analysed in Section 4.3, where nuclear provides its full 2 GW during the 100 hours of highest residual demand. Flexibility resources cannot fully substitute for this firm capacity contribution, but they can improve the conditions under which nuclear operates during the remaining hours of the year.

4.7.2. Country Comparison

The cross-country comparison of nuclear performance reveals how different national contexts shape nuclear economics and utilisation.

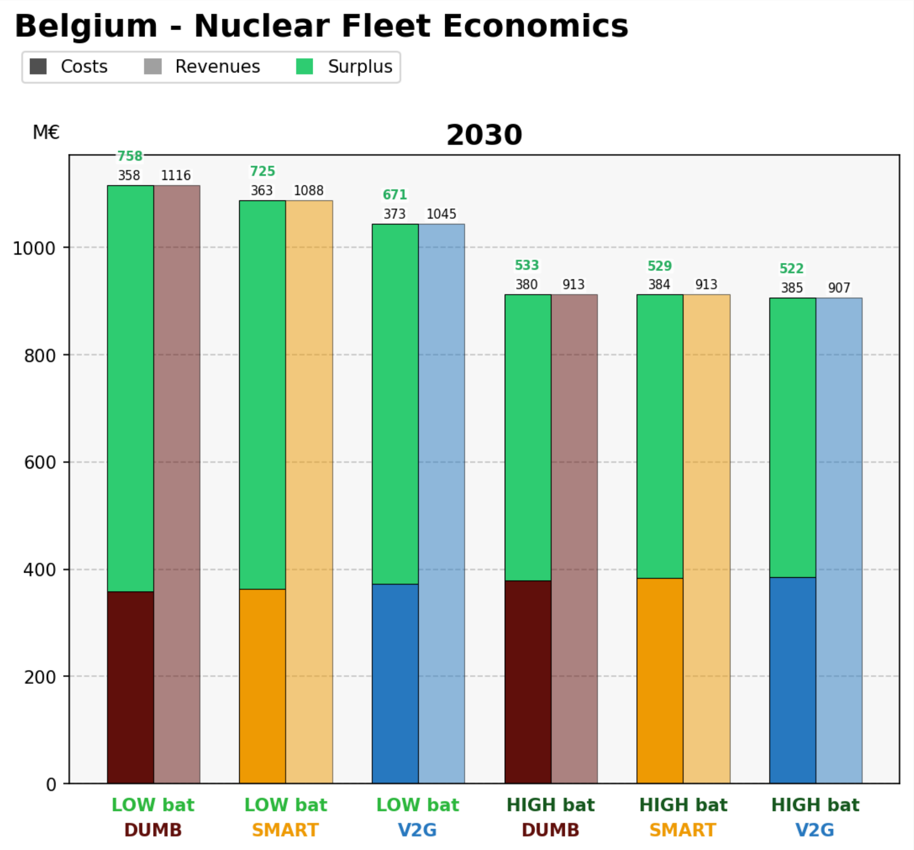


Figure 31: Nuclear fleet costs, revenues, and surplus in Belgium for 2030. Costs include fuel and operational expenses; revenues derive from electricity sales. Surplus represents the operating margin available to cover capital costs and provide returns.

Nuclear Capacity Across Countries

The countries studied exhibit markedly different nuclear situations. France operates the largest fleet at approximately 62 GW, producing 348–372 TWh in 2030 and 296–330 TWh in 2040. The United Kingdom operates 5.5 GW in 2030, expanding to 13 GW by 2040 through new construction (reflecting projects such as Hinkley Point C and Sizewell C). Belgium operates 2 GW in 2030 only. The Netherlands operates a single unit at Borssele (0.5 GW) in 2030, phasing out by 2040. Germany has completed its nuclear phase-out and operates no nuclear capacity in either time horizon. Figure 32 and Figure 33 present nuclear production and associated capacity factors across countries.

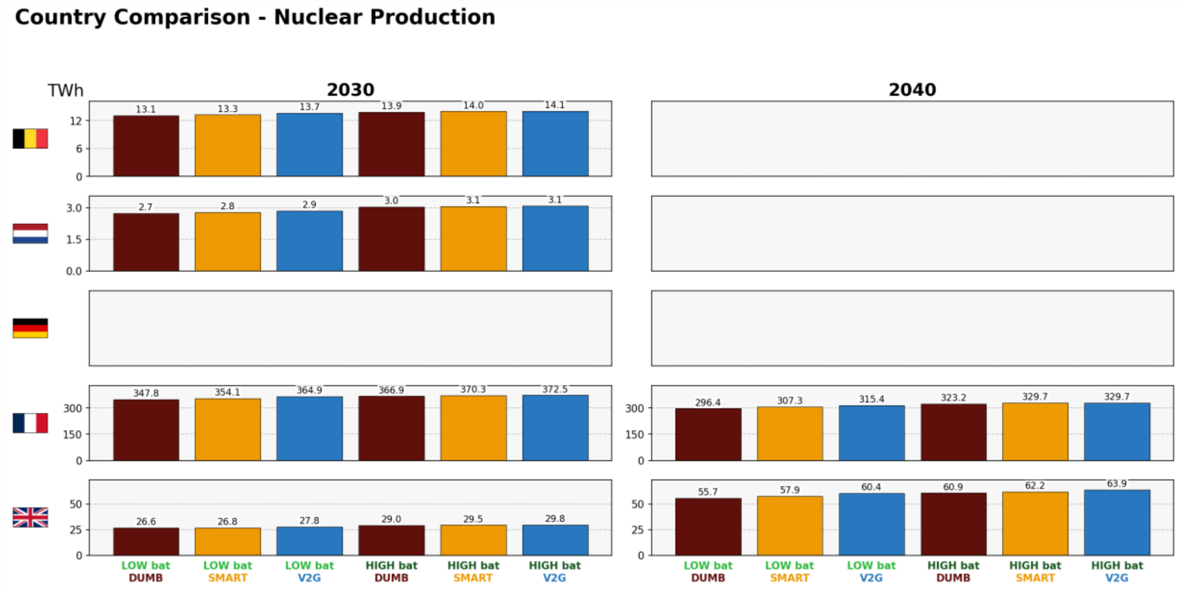


Figure 32: Annual electricity production from nuclear plants across countries for 2030 and 2040.

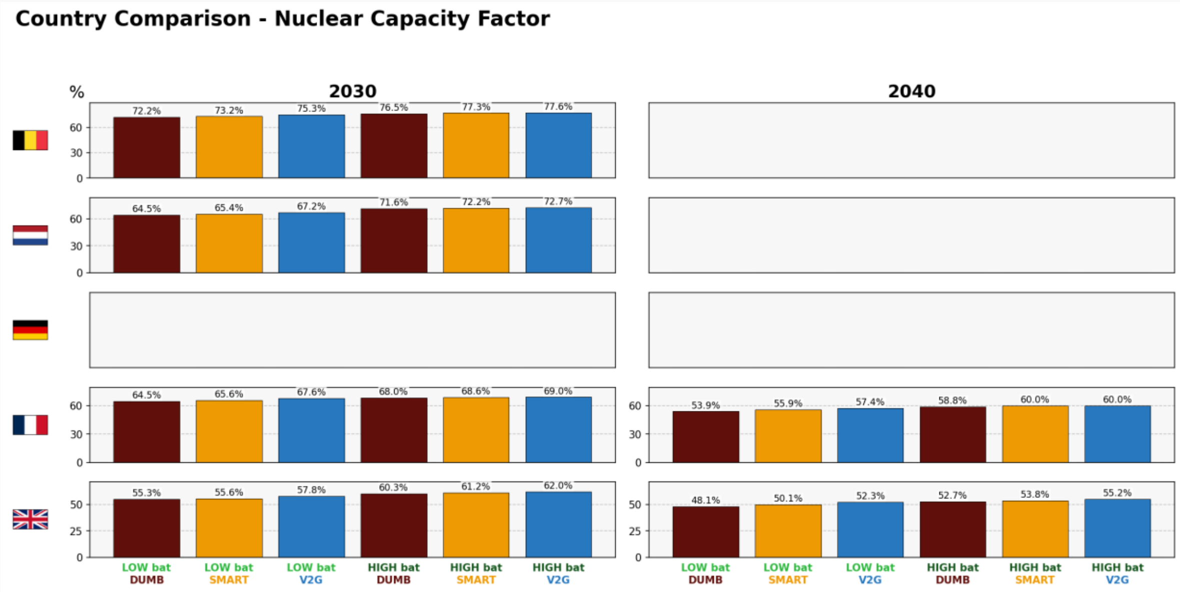


Figure 33: Nuclear capacity factor across countries for 2030 and 2040. Higher values indicate more intensive utilisation; lower values indicate more frequent curtailment or cycling.

The same pattern observed in Belgium, where flexibility increases nuclear capacity factors, holds across all countries with nuclear capacity. French nuclear capacity factors rise from 65% (LOW BAT DUMB) to 69% (HIGH BAT V2G) in 2030, and from 54% to 60% in 2040. UK capacity factors increase from 55% to 62% in 2030, and from 48% to 55% in 2040. The Netherlands shows a similar pattern: 65% to 73% in 2030.

Belgium achieves the highest nuclear capacity factors among the countries studied. This reflects Belgium's relatively modest renewable penetration compared to neighbours such as the Netherlands and Germany, which reduces the frequency of renewable surplus events that pressure nuclear to reduce output. France's larger renewable deployment and the UK's ambitious offshore wind programme create more frequent surplus conditions that constrain nuclear utilisation even in flexibility-rich scenarios.

The decline in French and UK capacity factors from 2030 to 2040 reflects the substantial increase in solar capacity projected over this period. French solar capacity roughly doubles between the time horizons, and UK solar similarly expands substantially. The resulting increase in midday production surpluses creates more frequent conditions where nuclear must reduce output, even when flexibility resources partially absorb the surplus.

Economic Performance Across Countries

Figure 34 presents per-GW surplus across countries with nuclear capacity.

Several patterns emerge from the cross-country economic comparison:

Belgian nuclear achieves the highest per-GW surplus in 2030: €365 million/GW in LOW BAT DUMB, falling to €252 million/GW in HIGH BAT V2G. This relatively strong performance reflects Belgium's market position as an interconnected hub where wholesale prices remain elevated due to limited domestic generation alternatives.

French nuclear shows substantial surplus but at lower per-GW levels than Belgium: €285 million/GW in 2030 LOW BAT DUMB, falling to €188 million/GW in HIGH BAT V2G. The lower French figures reflect the country's historically lower wholesale prices, driven by the abundant nuclear capacity itself. France's nuclear fleet is so large that its own operation substantially influences market prices, creating a self-limiting dynamic where increased output depresses the prices that output receives.

An intriguing pattern emerges in the French 2040 results. Per-GW surplus in LOW BAT DUMB reaches €480 million/GW, substantially exceeding the 2030 figure of €285 million/GW. This counterintuitive increase reflects France's projected transition from net electricity exporter to net importer, as documented in Section 4.1. Higher wholesale prices in 2040 (driven by this tightening supply-demand balance) benefit nuclear revenues despite lower capacity factors. However, this effect diminishes substantially in high-flexibility scenarios: 2040 HIGH BAT V2G surplus falls to €214 million/GW as price compression erodes the windfall.

UK nuclear shows the lowest per-GW surplus among countries with nuclear capacity: €181 million/GW in 2030 LOW BAT DUMB, falling to €167 million/GW in HIGH BAT V2G. The UK's already-low wholesale prices (documented in Section 4.4), driven by abundant offshore wind, limit the revenue potential for all dispatchable generation including nuclear. By 2040, UK per-GW surplus improves to €363 million/GW in LOW BAT DUMB, reflecting higher prices as demand growth outpaces supply, but falls to €199 million/GW in HIGH BAT V2G.

The Flexibility–Nuclear Nexus: Universal Patterns

Despite national differences, several universal patterns emerge regarding nuclear operation in flexibility-rich systems:

First, **flexibility deployment consistently enables higher nuclear utilisation across all countries**. Capacity factors rise by 4–8 percentage points between LOW BAT DUMB and HIGH BAT V2G scenarios. This represents a meaningful operational benefit: fewer cycling events, more stable output, and reduced wear on reactor components.

Second, this operational benefit comes at an economic cost. Despite higher output, nuclear revenues decline with flexibility deployment as price compression reduces the value of each MWh produced. The reduction in per-GW surplus ranges from 25–35% between least and most flexible scenarios.

Third, the net effect on nuclear viability depends on which metric is prioritised. From an energy security perspective, higher capacity factors represent improved utilisation of low-carbon firm capacity and a higher level of energy independence.

From an investor perspective, lower margins may create challenges for cost recovery, particularly for new nuclear construction where capital costs dominate.

Fourth, **the asymmetric relationship between nuclear and flexibility operates universally**. Nuclear cannot substitute for the short-duration flexibility that batteries and EVs provide, but it offers firm capacity that no amount of flexibility can fully replace during prolonged periods of low renewable output. **These resources are complements in system architecture even as they are partial competitors in market revenues**.

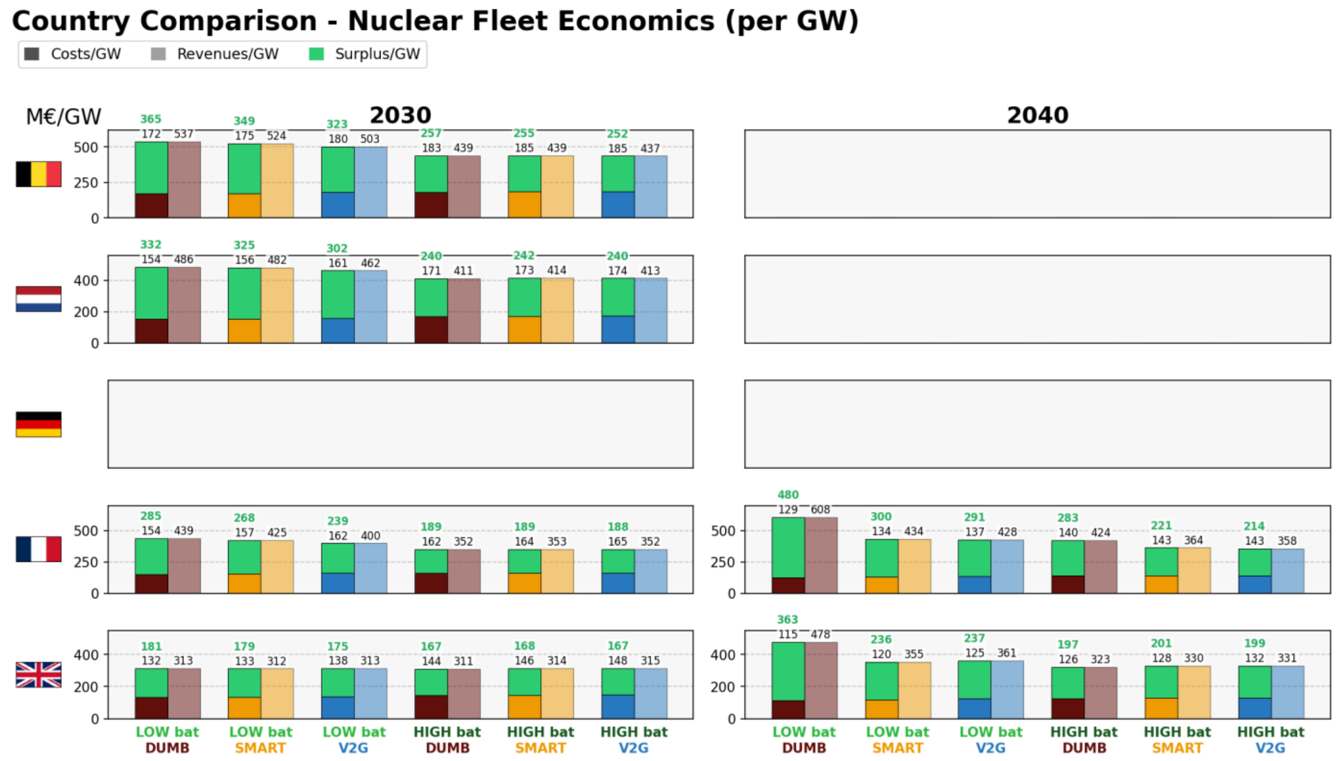


Figure 34: Nuclear fleet surplus per GW of installed capacity across countries for 2030 and 2040. Per-GW normalisation enables meaningful comparison despite vastly different fleet sizes.

Implications for Nuclear Investment and Policy

The analysis suggests several implications for nuclear policy in the European context:

For existing nuclear fleets (France, remaining Belgian capacity), flexibility deployment is operationally beneficial but economically challenging. Plant operators should anticipate declining energy market revenues even as output remains stable or increases. Capacity mechanisms and other non-energy revenue streams become increasingly important for cost recovery.

For new nuclear construction (UK, potentially others), the economics appear highly sensitive to the flexibility landscape that will exist when plants enter service. Projects justified on the basis of current market conditions may face different revenue profiles if flexibility deployment exceeds expectations. Contracts-for-differences and similar arrangements that guarantee minimum prices, as used for UK projects, provide important risk mitigation against this uncertainty.

For system planners, the results reinforce that nuclear and flexibility serve complementary roles. A strategy that relies exclusively on flexibility to manage variability would lack the firm capacity needed during prolonged adverse weather; a strategy that relies exclusively on nuclear would lack the agility needed to manage hourly and daily variability. The optimal portfolio includes both, even though their co-existence creates competitive pressure on market revenues for each.

The divergent nuclear policies across Europe (expansion in the UK and potentially France; phase-out in Germany and eventually Belgium) create an interesting natural experiment. As the system evolves toward 2040 and beyond, the relative merits of nuclear versus flexibility-dominated decarbonisation strategies will become clearer. The modelling results presented here suggest that both approaches can function technically, but with substantially different implications for market structure, investment requirements, and risk allocation.

4.8. CCGT Production, Capacity Factor, and Economics

4.8.1. Belgium

As the primary dispatchable thermal generation technology available to balance variable renewable generation, CCGTs serve essential functions: filling supply gaps during low-wind, low-solar periods; providing ramping capability to match rapid demand changes; and ensuring system adequacy during stress events. However, the emergence of alternative flexibility resources fundamentally alters the economic environment in which these plants operate.

Production and Capacity Factor

Figure 35 presents CCGT production in Belgium across all scenario variants.

In 2030, CCGT production ranges from 11.1 TWh in the LOW BAT DUMB scenario to 8.5 TWh in the HIGH BAT V2G scenario, a reduction of 24%. This decline reflects the displacement of gas-fired generation by flexibility resources: **batteries and smart-charging EVs absorb renewable surpluses that would otherwise require curtailment, then discharge during periods when CCGTs would otherwise have operated**. The effect operates through market prices: by compressing price spreads (as documented in Section 4.4), flexibility resources reduce the hours during which CCGTs can profitably dispatch.

By 2040, CCGT production in absolute terms is surprisingly similar to 2030 levels: 10.8 TWh in LOW BAT DUMB falling to 7.8 TWh in HIGH BAT V2G. However, this apparent stability masks an important underlying dynamic. Installed CCGT capacity rises from 3.5 GW in 2030 to 5.5 GW in 2040, a 56% increase reflecting anticipated system needs as nuclear capacity phases out. **The fact that production remains flat despite this capacity expansion indicates a fundamental shift in how CCGTs operate: from semi-baseload generation toward true peaking duty with lower average utilisation**.

Figure 36 presents capacity factors, which reveal this operational transformation more clearly.

CCGT capacity factors decline systematically with increasing flexibility. In 2030, capacity factors range from 36% (LOW BAT DUMB) to 28% (HIGH BAT V2G), representing a 24% relative reduction in plant utilisation. The pattern persists in 2040, with capacity factors falling from 28% to 23% across the same scenario range.

To interpret these figures, consider that a 36% capacity factor corresponds to approximately 3,150 full-load hours annually, whilst a 23% capacity factor implies roughly 2,000 hours. This reduction of over 1,000 operating hours represents a substantial shift in plant economics: fixed costs must be recovered over fewer operating hours, whilst competition for the remaining hours intensifies as flexibility resources claim an increasing share of high-value dispatch periods.

Fleet Economics

The operational changes documented above translate directly into economic consequences. Figure 37 presents total fleet costs, revenues, and surplus.

In 2030, fleet revenues decline from €1,221 million (LOW BAT DUMB) to €685 million (HIGH BAT V2G), a 44% reduction. Operating surplus (revenues minus variable costs) falls even more dramatically: from €694 million to €281 million, a 60% reduction. This amplified decline in surplus compared to revenues reflects the fact that costs remain relatively stable

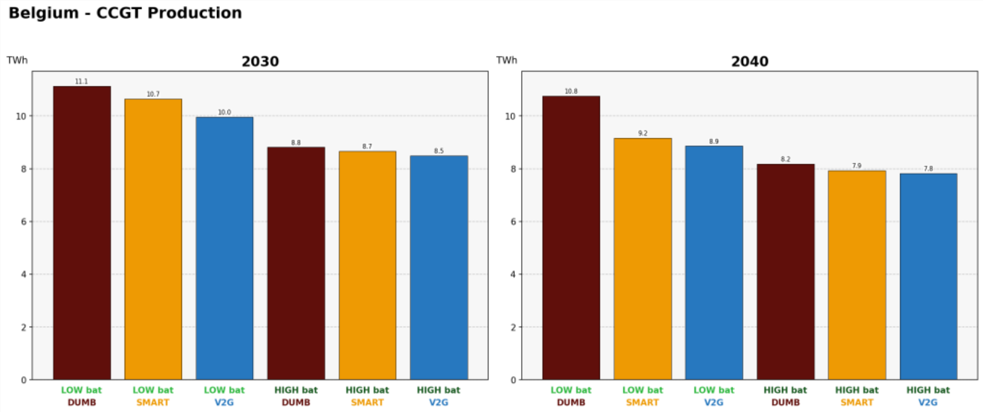


Figure 35: Annual electricity production from CCGT plants in Belgium for 2030 and 2040 across all scenario variants.

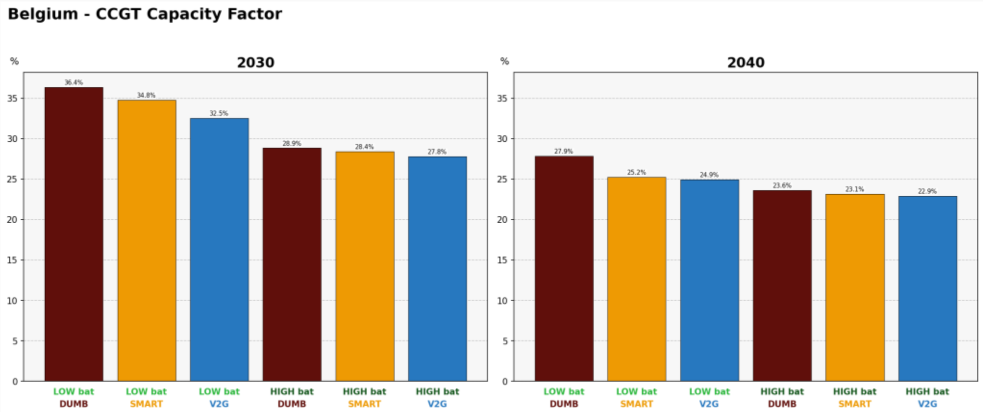


Figure 36: CCGT capacity factor in Belgium for 2030 and 2040. Capacity factor represents actual production divided by maximum possible production if plants operated continuously at full output.

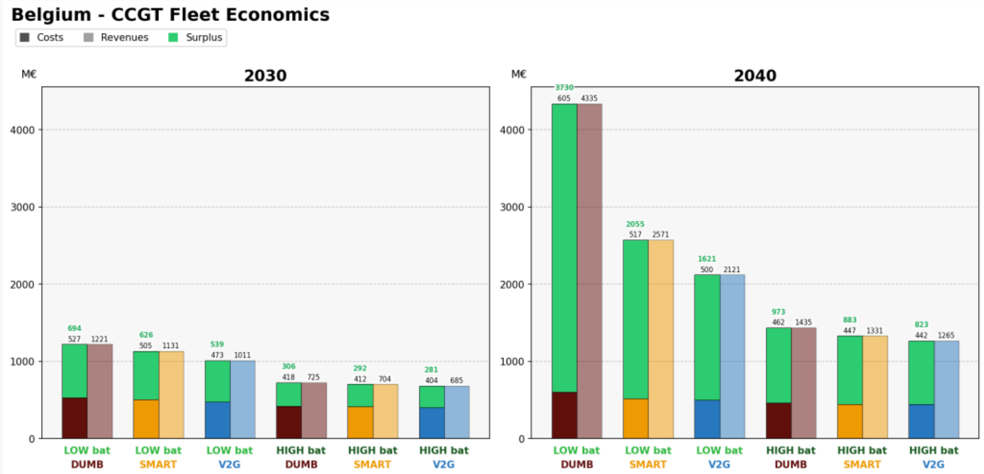


Figure 37: CCGT fleet economics in Belgium for 2030 and 2040. Left bars show costs plus surplus (stacked); right bars show revenues. Surplus represents the operating margin available to cover capital costs and provide returns to investors.

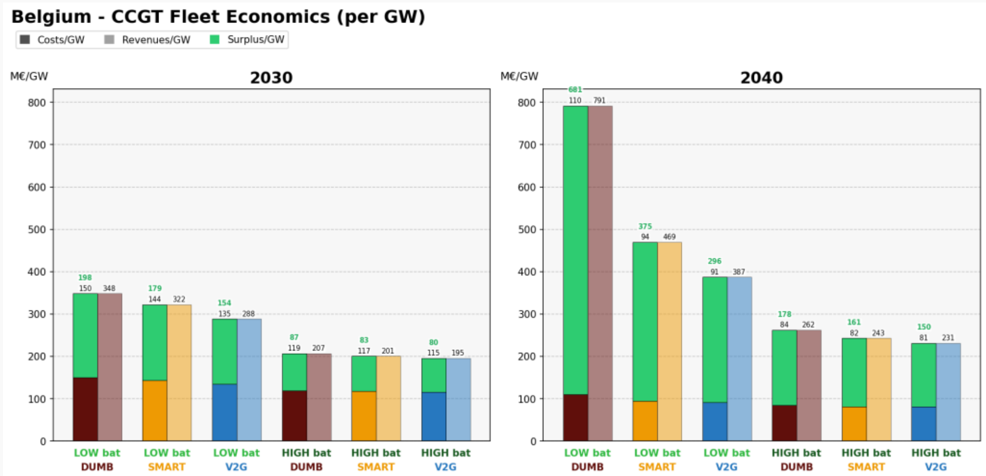


Figure 38: CCGT fleet economics per GW of installed capacity in Belgium for 2030 and 2040. Normalisation enables comparison across scenarios with different installed capacities.

whilst revenues collapse; fixed operational costs cannot be reduced proportionally when dispatch hours fall.

The mechanism underlying this revenue erosion is the elimination of scarcity pricing events documented in Section 4.4. CCGTs earn their highest margins during hours when supply is tight and prices spike. **The near-elimination of scarcity events in HIGH BAT scenarios removes the highest-margin operating hours from CCGT portfolios**.

By 2040, the dynamics intensify. In the LOW BAT DUMB scenario, extreme price volatility creates extraordinary profit potential: fleet revenues reach €4,335 million and surplus €3,730 million. These figures, roughly five times the 2030 levels, reflect the severe system stress in a low-flexibility 2040 system where nuclear capacity has phased out, solar capacity has nearly doubled, but insufficient flexibility exists to manage the resulting variability. **CCGTs operating during the 640 hours of prices exceeding 150 €/MWh** (including 238 hours at the 3,000 €/MWh ceiling) **capture enormous rents**.

However, flexibility deployment largely eliminates this windfall. In the 2040 HIGH BAT V2G scenario, revenues fall to €1,265 million and surplus to €823 million, reductions of 71% and 78% respectively from LOW BAT DUMB. **The same installed CCGT fleet can earn either €3,730 million or €823 million annually depending on whether flexibility resources are deployed. This nearly fivefold difference in surplus illustrates the profound economic uncertainty facing CCGT investors**.

Figure 38 presents fleet economics normalised per GW of installed capacity, enabling clearer interpretation of unit profitability.

Per-GW surplus in 2030 ranges from €198 million/GW (LOW BAT DUMB) to €80 million/GW (HIGH BAT V2G). For context, a new CCGT plant might cost approximately €700–900 million per GW to construct, with an economic life of 25–30 years. Annualised capital recovery at a 7% discount rate would require roughly €70–90 million per GW annually. Against this benchmark, the 2030 LOW BAT scenarios appear comfortable (€150–200 million/GW surplus), but HIGH BAT V2G scenarios (€80 million/GW) approach the threshold where pure energy market revenues may be insufficient.

By 2040, per-GW surplus in LOW BAT DUMB reaches €681 million/GW, an extraordinary figure reflecting extreme market conditions. However, HIGH BAT V2G surplus falls to €150 million/GW. The 2040 figures must be interpreted cautiously: the LOW BAT DUMB scenario represents a system under severe stress that would likely trigger policy interventions well before such conditions materialised.

Investment Risk and Policy Implications

If flexibility deployment proceeds slowly (closer to DUMB scenarios), **and stationary battery investment remains modest** (LOW BAT), **CCGTs could earn attractive returns**. The extreme scenario of 2040 LOW BAT DUMB suggests potential for windfall profits that would handsomely reward patient capital. **However, if smart charging and V2G become widespread**, and battery deployment expands as assumed in HIGH BAT scenarios, **the same CCGTs would struggle to cover their capital costs** from energy market revenues alone.

This uncertainty is compounded by the asymmetric nature of the outcomes. In flexibility-rich scenarios, CCGTs earn modest but still positive surpluses; they are not rendered worthless, but their returns fall below levels that would justify new investment without additional support. In flexibility-poor scenarios, CCGTs earn exceptional returns. The expected value across these scenarios might appear adequate, but the distribution of outcomes creates planning challenges.

The dependence on scarcity pricing deserves particular attention. CCGTs are designed to operate during system stress, earning high margins that compensate for low utilisation. Flexibility deployment systematically erodes this business model by eliminating the scarcity hours that generate peak revenues. Whether this erosion represents a market failure or a market success depends on perspective: consumers benefit from reduced price volatility, whilst CCGT investors see their revenue base shrinking.

Two observations emerge for policymakers. First, the economic viability of CCGTs increasingly depends on capacity payments or other non-energy revenues. In high-flexibility scenarios, energy market revenues alone appear insufficient to justify continued operation of existing plants, let alone new investment. **Capacity mechanisms that reward availability regardless of actual dispatch become essential for maintaining the dispatchable generation that even flexibility-rich systems require during prolonged periods of low renewable output**.

Second, **flexibility deployment and CCGT investment decisions are interdependent**. Investors cannot know which flexibility scenario will materialise, and their investment decisions will partly determine the outcome. If investors assume a flexibility-rich future and withhold CCGT investment, the resulting capacity shortfall might create exactly the scarcity conditions that would have justified the foregone investment. Conversely, if investors assume flexibility will disappoint and build substantial CCGT capacity, they may face stranded asset risk if flexibility deployment exceeds expectations.

4.8.2. Country Comparison

The cross-country comparison reveals how national generation mixes and flexibility landscapes shape CCGT economics across European markets. Figure 39 presents capacity factors across Belgium, Germany, France, the Netherlands, and the United Kingdom.

Capacity Factor Patterns

Belgium exhibits the highest CCGT capacity factors among the countries studied: 36% in 2030 LOW BAT DUMB, falling to 23% in 2040 HIGH BAT V2G. This relatively high utilisation reflects Belgium's limited domestic generation alternatives. **With nuclear phasing out, modest hydropower resources, and high import dependence, Belgian CCGTs face less competition from zero-marginal-cost generation than their counterparts in countries with larger renewable or nuclear fleets**.

Germany shows intermediate capacity factors: 19% in 2030 LOW BAT DUMB falling to 12% in 2040 HIGH BAT V2G. The lower German figures reflect the enormous scale of renewable deployment assumed in the TYNDP scenarios (366 GW solar, 159 GW onshore wind by 2040). German CCGTs face intense competition from renewable generation during an increasing number of hours, limiting their operating opportunities to periods of genuine scarcity.

France exhibits even lower CCGT utilisation: 18% in 2030 falling to just 6% by 2040 in HIGH BAT scenarios. This pattern reflects France's nuclear-hydro system providing substantial flexibility that reduces the need for gas-fired generation. French CCGTs operate primarily as true peakers, dispatching only during the most extreme conditions when nuclear and hydro cannot meet demand alone.

The Netherlands shows capacity factors of 19% in 2030 falling to 9% by 2040, reflecting its solar-heavy generation mix that creates pronounced daily variability. Dutch CCGTs operate during morning and evening peaks but face stiff competition from the large battery fleet assumed in HIGH BAT scenarios.

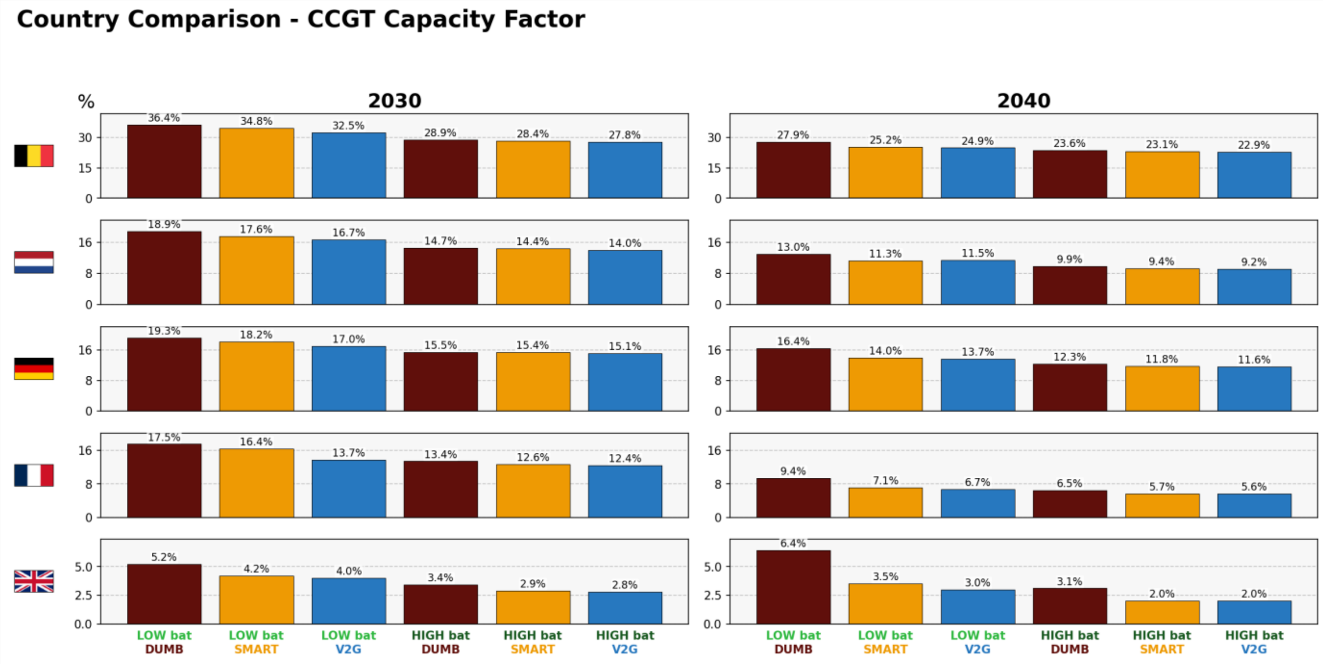


Figure 39: CCGT capacity factor across countries for 2030 and 2040. Belgium shows the highest capacity factors; the UK shows the lowest.

The United Kingdom presents the most striking pattern: CCGT capacity factors of just 5% in 2030, falling to 2–3% by 2040 in HIGH BAT scenarios. **The UK's ambitious offshore wind deployment** (52 GW by 2030, 95 GW by 2040) **generates such abundant electricity that CCGTs find few hours of profitable operation**. The UK effectively achieves wind-dominated system operation where gas-fired generation becomes a true reserve capacity, dispatching only during extended calm periods.

Economic Consequences Across Countries

Figure 40 presents per-GW surplus across countries.
The economic patterns mirror capacity factor differences. Belgian CCGTs earn the highest per-GW surplus in 2030: €198 million/GW in LOW BAT DUMB, compared to €196 million/GW in Germany, €148 million/GW in the Netherlands, €140 million/GW in France, and just €19 million/GW in the United Kingdom.

The UK figures merit particular attention. At €19 million/GW in 2030 LOW BAT DUMB (falling to €11 million/GW in HIGH BAT V2G), **UK CCGTs earn per-GW surpluses well below any plausible capital recovery threshold**. This finding suggests that UK CCGT capacity cannot be sustained through energy market revenues alone; capacity payments or other support mechanisms become essential for maintaining any gas-fired generation in a wind-dominated system.

By 2040, the cross-country variation intensifies. Germany shows the highest per-GW surplus at €1,120 million/GW in LOW BAT DUMB, reflecting the extreme price volatility that its massive but inflexible renewable deployment would create.

France presents a distinctive pattern where 2040 per-GW surplus (€385 million/GW in LOW BAT DUMB) actually exceeds 2030 levels (€140 million/GW). This counterintuitive result reflects France's projected transition from net exporter to net importer (documented in Section 4.1), which creates tighter supply conditions and higher prices. French CCGTs, whilst operating infrequently, earn substantial margins when they do dispatch.

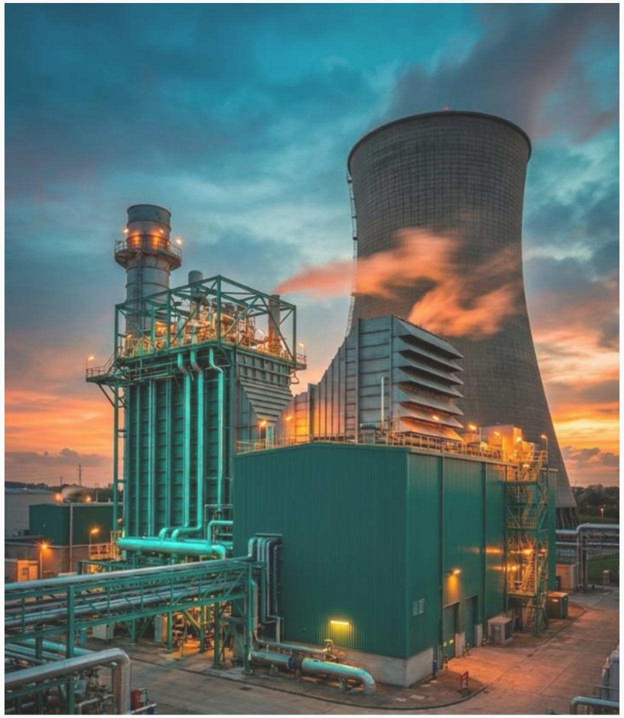
Universal Patterns

Despite national differences, several patterns emerge consistently:

First, flexibility deployment reduces CCGT profitability across all countries. **Moving from LOW BAT DUMB to HIGH BAT V2G reduces per-GW surplus by 50–80% in every country**. This finding confirms that the competitive pressure flexibility places on gas-fired generation is not Belgium-specific but operates throughout the interconnected European system.

Second, the ranking of countries by CCGT profitability remains relatively stable across scenarios. Belgium consistently shows higher per-GW returns than the UK, reflecting fundamental differences in generation mix that flexibility deployment does not eliminate. This suggests that **CCGT investment attractiveness varies structurally across European markets**.

Third, the relationship between CCGT economics and battery economics (documented in Section 4.5) involves complex interdependencies. Both CCGTs and batteries earn revenues by serving during high-price periods; when flexibility resources eliminate scarcity pricing, both resource types see diminished returns. However, the competitive pressure operates asymmetrically: **batteries contribute to eliminating scarcity events that CCGTs would have profited from, whilst CCGTs have limited ability to reciprocally affect battery profitability**. This asymmetry suggests that flexible resources hold a structural advantage in the emerging market environment.



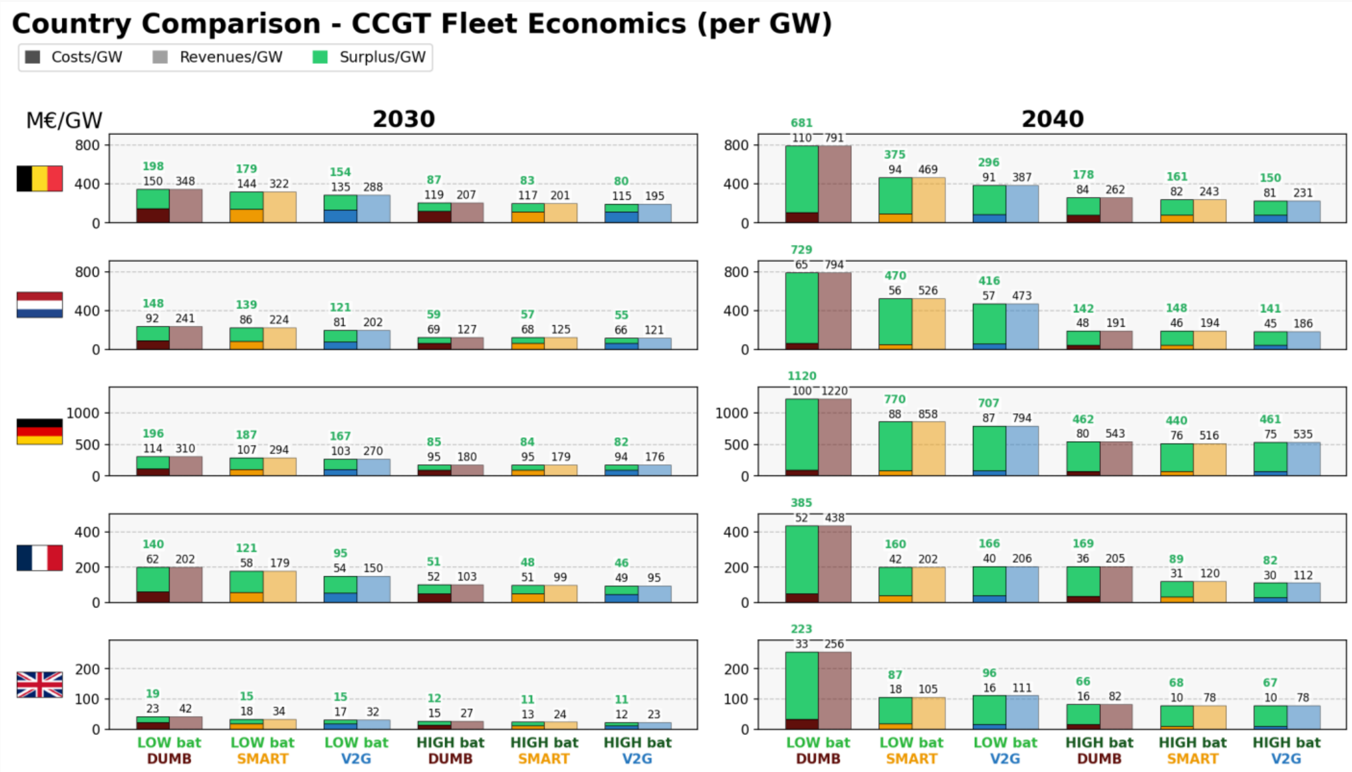


Figure 40: CCGT fleet surplus per GW of installed capacity across countries for 2030 and 2040.

The cross-country comparison reinforces a key insight: CCGT economics are highly context-dependent, but the fundamental dynamic of value erosion through flexibility deployment operates across all European markets. **The transition from energy-only revenues to capacity-dependent business models appears to be a pan-European phenomenon**, not a Belgian peculiarity.

4.9. Flexibility Needs and Contribution to Flexibility Needs

This section examines the system's flexibility requirements and how different technologies contribute to meeting them. The analysis distinguishes between daily flexibility (intra-day variability), weekly flexibility (variations between days), and annual flexibility (seasonal patterns), revealing which resources suit different balancing challenges.

4.9.1. Belgium

Figure 41 presents Belgium's flexibility needs across the three timescales.

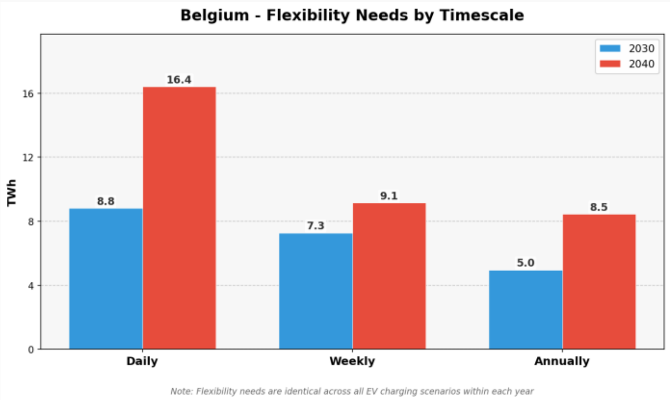


Figure 41: Flexibility needs in Belgium at daily, weekly, and annual timescales for 2030 and 2040. Values are identical across all scenarios within each year, as flexibility needs depend on renewable variability and demand patterns rather than the flexibility resources deployed.

Flexibility needs are exogenous to flexibility deployment. Daily flexibility needs stand at 8.8 TWh in 2030 and 16.4 TWh in 2040, regardless of EV charging behaviour or battery deployment levels. This invariance reflects that flexibility needs arise from the mismatch between variable renewable generation and demand patterns, not from the resources available to address them.

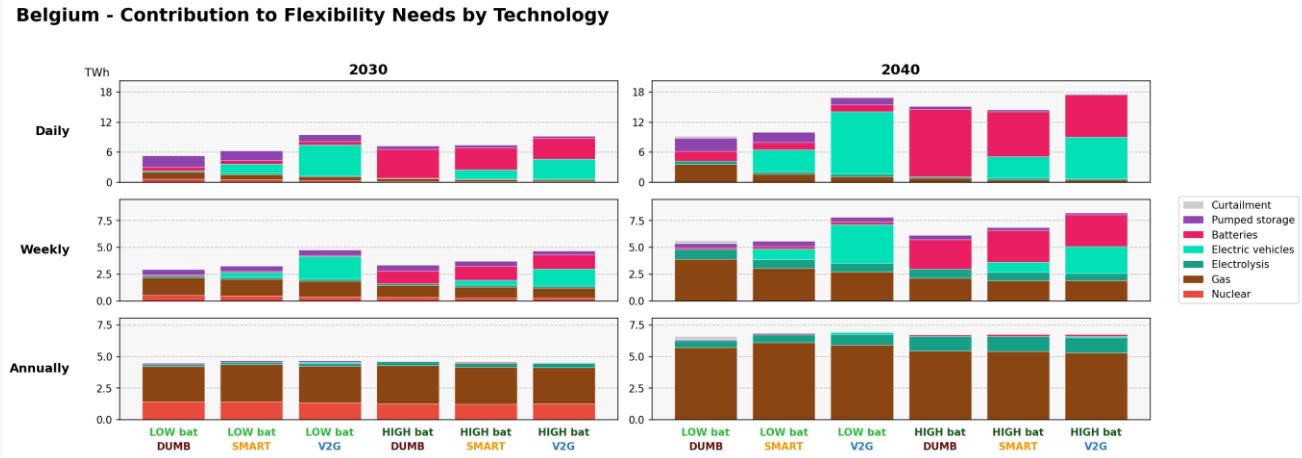


Figure 42: Contribution to flexibility needs by technology in Belgium for 2030 and 2040. Positive values indicate the technology helps balance residual load variations.

The near-doubling of daily flexibility needs between 2030 and 2040 reflects the substantial growth in solar PV capacity. Solar creates pronounced intra-day variability, with production concentrated at midday whilst demand peaks in mornings and evenings. **Weekly and annual flexibility needs grow more moderately** (from 7.3 to 9.2 TWh and 5.0 to 8.5 TWh respectively), as solar-dominated growth creates primarily daily challenges whilst wind contributes more to longer-duration patterns.

Which Technologies Meet These Needs

Whilst flexibility needs remain constant across scenarios, the technologies meeting them shift dramatically depending on battery deployment and EV charging behaviour. Figure 42 presents contributions to daily flexibility.

In the 2030 LOW BAT DUMB scenario, daily flexibility comes from a diverse mix: pumped hydro (2.3 TWh), gas (1.4 TWh), batteries (0.8 TWh), and nuclear (0.7 TWh). This baseline reflects what happens when EVs charge inflexibly and battery capacity is modest.

Smart charging introduces meaningful EV participation: 1.9 TWh in the SMART scenario, achieved purely through optimised charging timing without any bidirectional capability. Enabling V2G transforms the picture further: EV contribution rises to 6.2 TWh, making electric vehicles the single largest contributor to daily flexibility, exceeding pumped hydro (1.4 TWh) and substantially displacing gas (down to 0.8 TWh).

High battery deployment creates a different pattern. In 2030 HIGH BAT DUMB, batteries dominate with 5.8 TWh, whilst pumped hydro falls to 0.7 TWh and gas to 0.5 TWh. In 2030, batteries contribute 4.2 TWh and EVs 4.0 TWh; each resource's contribution is lower than it would be in isolation.

The potential scale of EV flexibility is most apparent in scenarios where batteries are scarce. In 2040 LOW BAT V2G, EVs contribute a remarkable 12.5 TWh to daily flexibility, far exceeding the modest battery contribution of 1.4 TWh. When large battery fleets are deployed alongside V2G (2040 HIGH BAT V2G), both resources share the load more evenly: 8.4 TWh from EVs and 8.3 TWh from batteries. This confirms the substitution effect: **EV contribution drops from 12.5 to 8.4 TWh when competing with abundant battery capacity**, consistent with the 65–72% reduction in V2G utilisation documented in Section 4.5.

Gas Displacement

Gas-fired generation serves as "flexibility of last resort" in scenarios with limited alternative resources. In LOW BAT DUMB, gas contributes 1.4 TWh (2030) and 3.6 TWh (2040) to daily flexibility. As batteries and EVs are deployed, this contribution collapses: to just 0.4 TWh in both 2030 and 2040 HIGH BAT V2G scenarios, representing reductions of 71% and 89% respectively.

This displacement is the mechanism through which flexibility reduces emissions (documented in Section 4.10). When batteries and EVs absorb renewable surpluses and discharge during peaks, they directly substitute for the ramping services gas would otherwise provide.

The Limits of Short-Duration Storage

At weekly and annual timescales, batteries and EVs contribute negligibly. Weekly battery contribution ranges from 0.07 to 1.3 TWh; annual contribution is essentially zero across all scenarios. Even V2G-capable EVs provide minimal annual flexibility (0.1 TWh).

Instead, **gas-fired generation dominates annual flexibility provision** (2.8–5.9 TWh), alongside nuclear where available (1.2–1.4 TWh). This reveals a fundamental limitation: lithium-ion batteries and EVs excel at shifting energy over hours to days, but cannot address seasonal imbalances. For longer-duration challenges, dispatchable thermal generation, hydrogen storage, and interconnection remain essential.

4.9.2. Country Comparison

The cross-country comparison reveals how national circumstances shape flexibility dynamics. Figure 43 presents flexibility needs across all countries.

Cross-country Differences in Flexibility Needs

The Netherlands shows particularly high daily needs relative to annual needs (36 vs 13 TWh in 2030), reflecting its solar-heavy mix that creates pronounced intra-day variability but stable seasonal patterns. **The United Kingdom shows the opposite: weekly needs (48 TWh) actually exceed daily needs** (38 TWh) in 2030, reflecting multi-day wind variability where output can remain low or high for several consecutive days.

France exhibits yet another pattern: annual flexibility needs (45 TWh) **exceed daily needs** (29 TWh), reflecting strong seasonality in heating-driven demand.

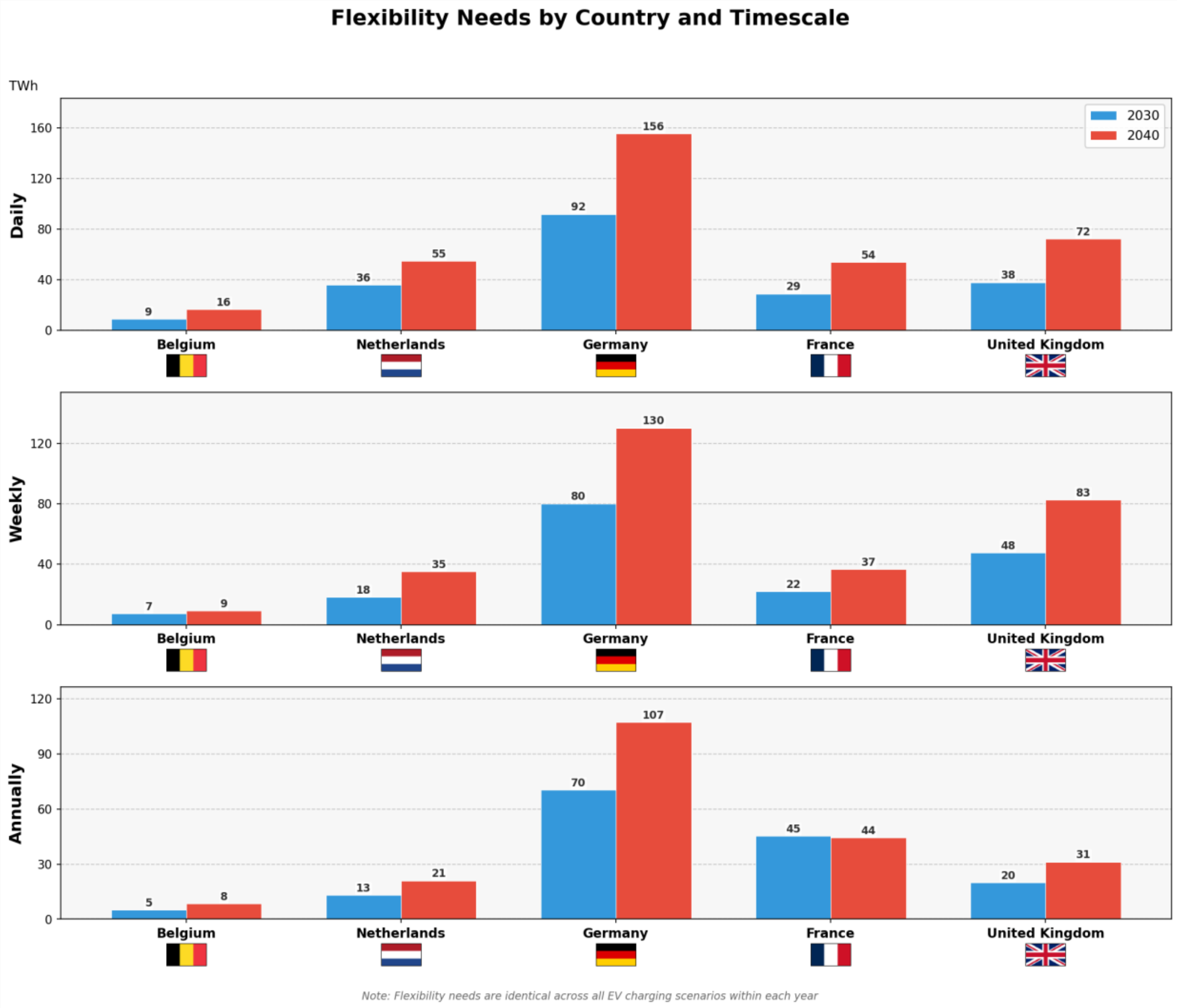


Figure 43: Flexibility needs by country and timescale for 2030 and 2040. Values are identical across scenarios within each country-year combination.

How Countries Meet Daily Flexibility Needs

Figure 44 present the contribution to flexibility needs by technology for each country.

National generation mixes fundamentally shape flexibility provision. In France, nuclear power itself contributes 15.5 TWh of daily flexibility in 2030 LOW BAT DUMB, over half of total provision, reflecting flexible nuclear operation. With this inherent flexibility available, French battery contribution remains modest even in HIGH BAT scenarios.

Germany faces flexibility challenges of enormous scale. Batteries alone contribute up to 65 TWh in HIGH BAT scenarios; EVs contribute 52 TWh in 2030 LOW BAT V2G, rising to 107 TWh by 2040. These volumes rival the total electricity consumption of smaller European countries.

The Netherlands shows the highest reliance on curtailment as a flexibility measure: 6–10 TWh in LOW BAT scenarios, reduced to under 1 TWh in HIGH BAT scenarios as batteries enable better renewable utilisation.

The United Kingdom exhibits high gas-fired flexibility contribution (10 TWh daily in 2030 LOW BAT DUMB), reflecting the ramping patterns created by wind variability. UK EVs in V2G scenarios contribute up to 25 TWh (2030) and 70 TWh (2040) to daily flexibility, amongst the highest values observed relative to system size.

Universal Patterns

Despite national differences, several patterns hold consistently. First, batteries and EVs provide primarily daily flexibility; weekly and annual balancing remains dominated by gas, hydro, and nuclear. Second, the competitive relationship between batteries and EVs operates universally: HIGH BAT scenarios show lower EV contributions than LOW BAT scenarios across all countries. Third, gas displacement through flexibility deployment occurs everywhere, with countries showing high gas reliance experiencing the largest reductions.

The cross-country comparison confirms that whilst flexibility scales vary enormously, the fundamental dynamics of how resources interact, compete, and substitute for conventional generation operate consistently throughout the European electricity system.

4.10. CO_2 Emissions

Flexibility deployment generates environmental benefits alongside the economic and operational effects documented in previous sections. This section examines how CO_2 emissions intensity varies across scenarios and time horizons, revealing the climate co-benefits of smarter electricity system operation.

4.10.1. Belgium

Figure 45 presents the CO_2 emissions intensity of Belgian electricity generation across all scenario variants.

CO_2 intensity declines systematically as flexibility deployment increases. In 2030, emissions intensity falls from 69 kg/MWh in the LOW BAT DUMB scenario to 60 kg/MWh in HIGH BAT V2G, a reduction of 12%. This translates to absolute emissions declining from 5.8 Mt to 5.0 Mt, **a 15% reduction achieved without any change to the installed generation mix**.

The mechanism underlying this improvement is the displacement of gas-fired generation documented in earlier sections. Flexibility resources absorb renewable surpluses that would otherwise be curtailed, then discharge during periods when CCGTs would otherwise operate. Each TWh shifted from peak to off-peak periods enables zero-carbon generation that would otherwise have been wasted, whilst displacing fossil-fuelled peaking output.

By 2040, the baseline system is substantially more decarbonised. Emissions intensity in LOW BAT DUMB falls to 30 kg/MWh, reflecting the combined effect of nuclear phase-out being offset by expanded renewable capacity and reduced CCGT utilisation. Flexibility deployment continues to provide environmental benefits: HIGH BAT V2G achieves 24 kg/MWh, a 21% improvement over the baseline. In absolute terms, total emissions fall from 3.0 Mt to 2.2 Mt across the scenario range.

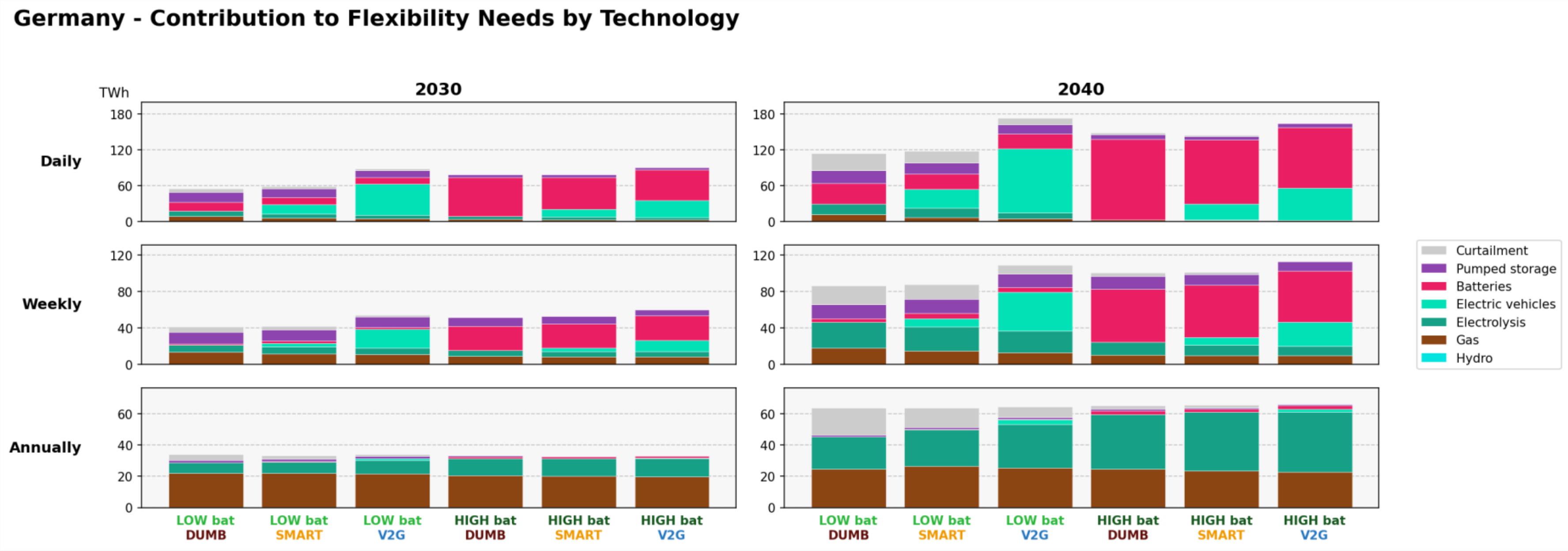
These emission reductions represent a "no-regrets" benefit of flexibility deployment. The environmental improvement arises purely from more intelligent use of existing resources, requiring no additional generation investment. This characteristic distinguishes flexibility-driven emissions reductions from other decarbonisation strategies that require substantial capital deployment.

4.10.2. Country Comparison

Figure 46 presents emissions intensity across the five countries studied.

National generation mixes fundamentally determine baseline emissions intensity. In 2030, Belgium exhibits the highest intensity among the countries studied at 69 kg/MWh (LOW BAT DUMB), reflecting its reliance on gas-fired generation to complement limited domestic renewable capacity. The Netherlands shows intermediate intensity at 40 kg/MWh, Germany at 25 kg/MWh, and the United Kingdom at 9 kg/MWh. France achieves the lowest intensity at just 5 kg/MWh, a consequence of its nuclear-dominated generation mix.

Flexibility deployment reduces emissions intensity across all countries, though the absolute magnitude varies with


Germany - Contribution to Flexibility Needs by Technology
2030
2040
TWh
Daily
Weekly
Annually
Curtailment
Pumped storage
Batteries
Electric vehicles
Electrolysis
Gas
Hydro
LOW bat DUMB
LOW bat SMART
LOW bat V2G
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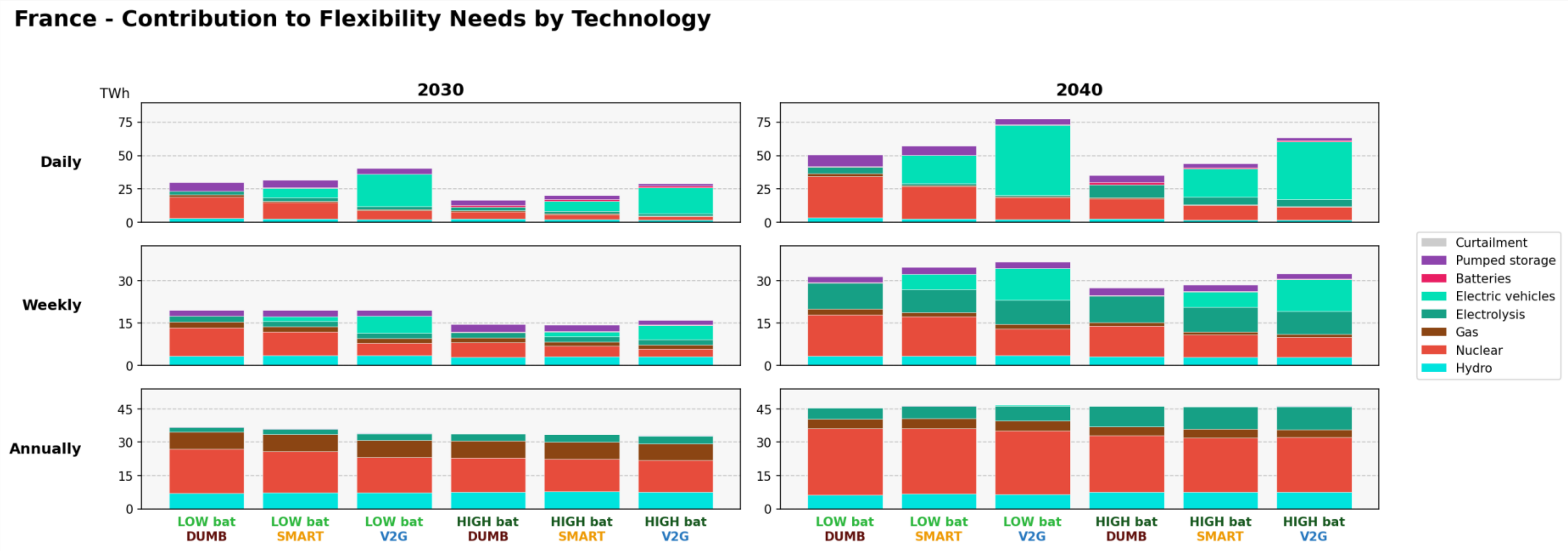
France - Contribution to Flexibility Needs by Technology
2030
2040
TWh
Daily
Weekly
Annually
Curtailment
Pumped storage
Batteries
Electric vehicles
Electrolysis
Gas
Nuclear
Hydro
LOW bat DUMB
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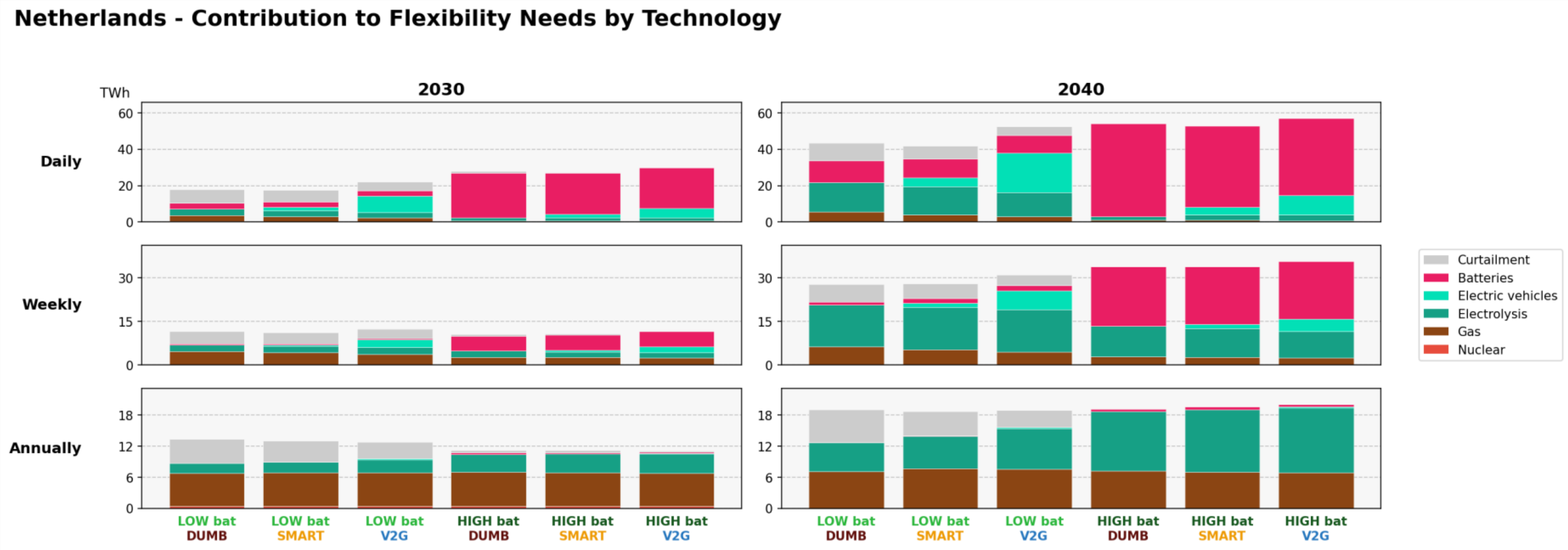


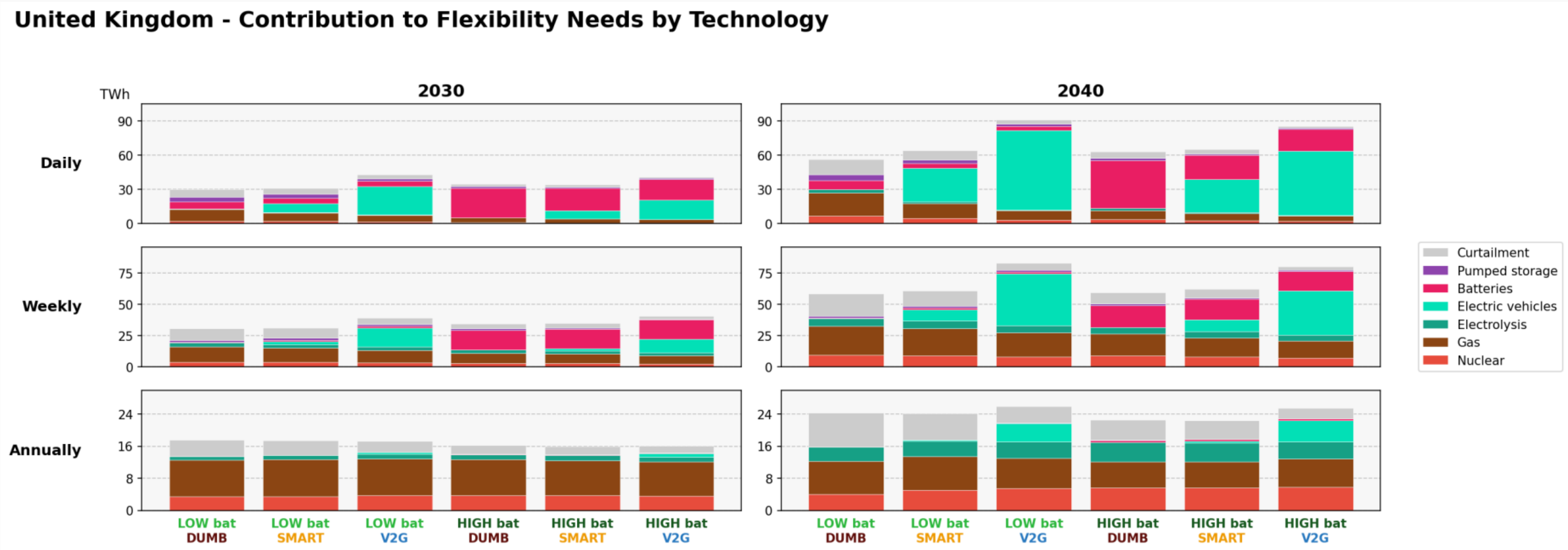


Figure 44: Contribution to flexibility needs by technology in Germany, France, The Netherlands and The United Kingdom for 2030 and 2040. Positive values indicate the technology helps balance residual load variations.

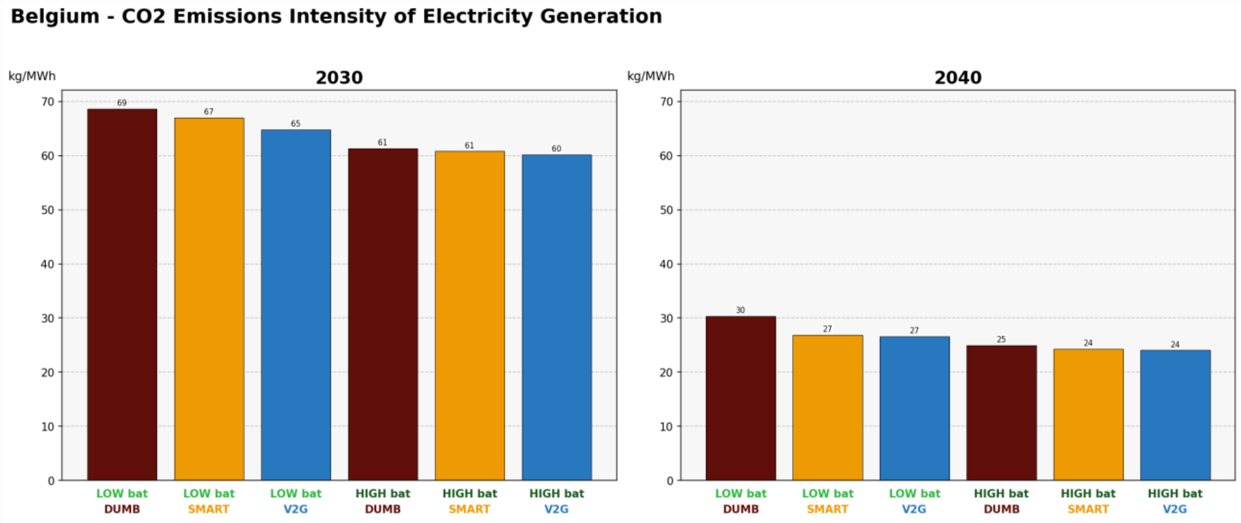


Figure 45: CO_2 emissions intensity of electricity generation in Belgium for 2030 and 2040. Values represent total CO_2 emissions divided by total electricity production, excluding storage throughput.

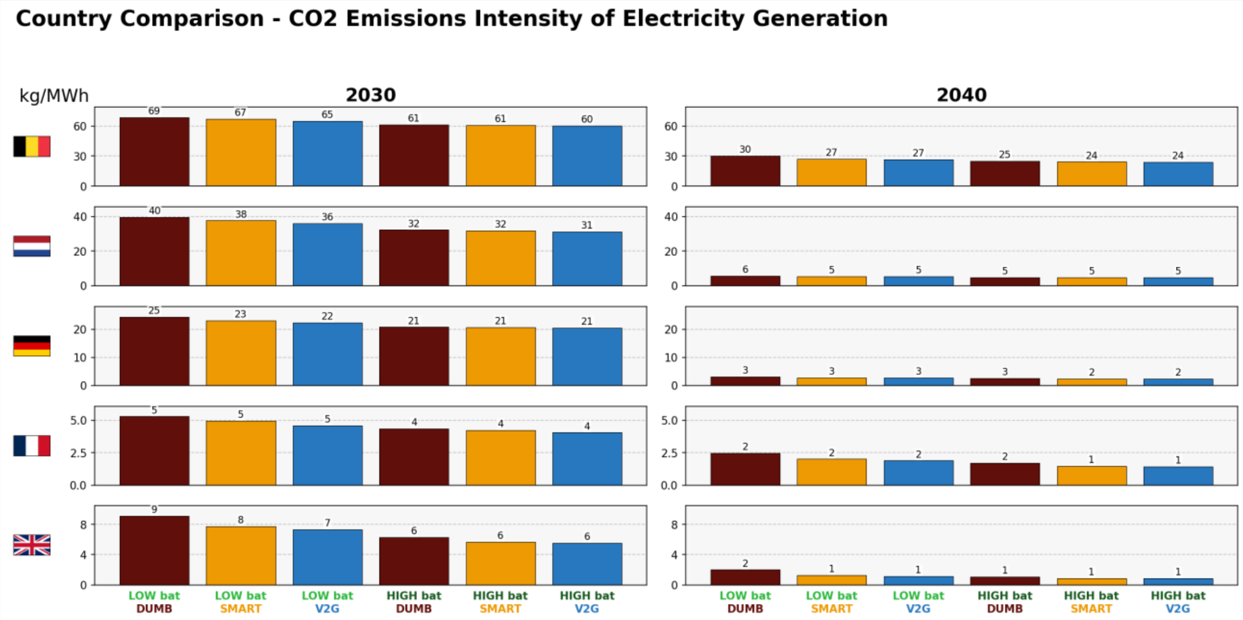


Figure 46: CO_2 emissions intensity of electricity generation across countries for 2030 and 2040.

baseline conditions. The United Kingdom shows the largest relative improvement: a 40% reduction from 9 to 6 kg/MWh between LOW BAT DUMB and HIGH BAT V2G scenarios in 2030. France, already operating at very low intensity, shows a smaller absolute reduction (from 5 to 4 kg/MWh) but a similar 23% relative improvement.

By 2040, all countries converge toward very low emissions intensities. France and the United Kingdom achieve near-complete decarbonisation at around 1 kg/MWh in flexibility-rich scenarios. Germany and the Netherlands reach 2–5 kg/MWh, reflecting their massive renewable deployment. Belgium remains the highest at 24 kg/MWh in HIGH BAT V2G, though this represents a substantial improvement from the 2030 baseline.

The cross-country comparison confirms that flexibility delivers environmental benefits regardless of national context. The magnitude of these benefits is largest in systems that currently rely on fossil-fuelled balancing; countries with already-clean generation mixes see smaller absolute improvements but similar relative gains. For Belgium, where gas-fired generation plays a substantial balancing role, the climate case for flexibility deployment is particularly strong.

5. Conclusion

Context and Scope

This report has examined the influence of electric vehicles and stationary batteries on the future Belgian electricity system, with particular attention to how these flexibility resources interact with each other and with the broader European context. The analysis builds upon the ENTSO-E TYNDP 2024 National Trends scenarios for 2030 and 2040, modified to create six distinct scenario variants representing combinations of stationary battery deployment (LOW BAT and HIGH BAT) and EV charging behaviour (DUMB, SMART, and V2G).

These scenarios are deliberately constructed as polar cases rather than probabilistic forecasts. The HIGH BAT assumptions, for instance, represent battery capacities that may never materialise at such scale, particularly given the economic challenges the simulations themselves reveal. Similarly, the universal adoption of smart charging or V2G across entire vehicle fleets represents an upper bound on what flexibility could theoretically deliver. The value of this approach lies not in predicting specific outcomes, but in revealing the mechanisms, sensitivities, and trade-offs that will shape how the electricity system evolves. The findings should be interpreted as insights into dynamics that policymakers, practitioners, and investors should be aware of, rather than as precise quantitative predictions.

Flexibility Creates Winners and Losers

A central finding of this analysis is that flexibility deployment does not benefit all market participants equally. The common intuition that "more flexibility is better for everyone" obscures important distributional consequences that deserve explicit attention.

Consumers emerge as clear beneficiaries. Flexibility resources compress electricity price distributions, reducing both average costs and exposure to extreme price spikes. The near-elimination of scarcity pricing events in flexibility-rich scenarios translates directly into lower and more predictable electricity bills. Industrial competitiveness improves when energy costs become stable enough to plan around. These consumer benefits are robust across scenarios and represent a strong public interest case for flexibility deployment.

The picture for asset owners is more nuanced. Stationary battery operators face the uncomfortable reality that successful flexibility deployment erodes the price spreads that make flexibility profitable. The first gigawatts of battery capacity capture substantial arbitrage value; subsequent capacity faces progressively narrower spreads as the collective action of flexibility resources compresses the very price differentials they exploit. This dynamic is well understood in energy economics, but the simulations add useful colour regarding magnitude: per-gigawatt battery surplus declines substantially as deployment increases, with the reduction particularly pronounced when competing against flexible EV charging.

Gas-fired generation faces perhaps the starkest challenge. CCGT revenues decline dramatically in flexibility-rich scenarios, with per-gigawatt surplus falling by 50 to 80 percent across the scenario range. This represents what might be understood as a second wave of economic pressure on thermal generation. The first wave arrived in the 2010s, when the rise of renewable generation and the

resulting merit order effect eroded CCGT operating hours and margins, ultimately prompting the emergence of capacity remuneration mechanisms across Europe, including Belgium. Now, as flexibility resources mature, a second mechanism of revenue erosion emerges: batteries and smart-charging EVs eliminate the scarcity pricing events during which CCGTs earn their highest remaining margins. The plants remain essential for system adequacy during prolonged periods of low renewable output, but the high-value operating hours that once compensated for low utilisation are progressively claimed by competing flexibility. Belgium's CRM already recognises the first wave; the simulation results underscore that the second wave may prove equally challenging as flexibility penetration grows.

Nuclear power presents an interesting paradox. Flexibility deployment enables higher nuclear capacity factors by absorbing renewable surpluses that would otherwise pressure nuclear plants to reduce output. Doel 4 and Tihange 3 would operate more smoothly in a flexibility-rich system. However, the same price compression that benefits consumers reduces the value of each megawatt-hour nuclear plants produce. Higher output coincides with lower revenues per unit, leaving nuclear operators operationally better off but economically challenged. This asymmetry, where flexibility and nuclear are complements in system architecture but partial competitors in market revenues, illustrates the broader theme that system-wide benefits do not automatically translate into adequate private returns.

Smart Charging: The Priority for Policy

Among the flexibility options examined, unidirectional smart charging stands out as a clear priority. Smart charging requires minimal additional hardware beyond what EV owners already install, imposes no additional degradation on vehicle batteries, and faces fewer consumer acceptance barriers than bidirectional alternatives. Yet despite this simplicity, smart charging delivers substantial system benefits.

The mechanism is straightforward: by shifting EV charging to periods of low prices (which typically coincide with high renewable generation), smart charging helps absorb renewable surpluses that might otherwise be curtailed. This temporal alignment improves overall system efficiency without requiring energy to cycle through storage losses. Stationary batteries incur round-trip efficiency losses of approximately 8 to 9 percent; smart EV charging that merely shifts demand timing triggers no such losses, giving it an inherent efficiency advantage for load-shifting applications.

The simulation results consistently show smart charging contributing meaningfully to daily flexibility provision across all countries and scenarios. This contribution comes essentially "for free" in the sense that vehicles must charge regardless; the only question is when. The policy implication is clear: it should be a near-term priority to ensure that the infrastructure, market arrangements, and consumer incentives exist to enable widespread smart charging. The research and development needed to make smart charging work seamlessly at scale, including communication protocols, aggregator platforms, and tariff structures that pass through appropriate price signals, represents high-value investment.

Vehicle-to-grid capability adds further flexibility potential, but its value is more conditional. In scenarios with limited stationary battery deployment, V2G provides substantial additional flexibility and earns meaningful arbitrage revenues. However, when large battery fleets are deployed alongside V2G-capable vehicles, both resources compete for similar value pools. The simulations show V2G utilisation declining substantially under HIGH BAT scenarios, as stationary batteries absorb arbitrage opportunities that V2G would otherwise capture.

This finding warrants some caution in interpretation. The model treats both resources as optimising against wholesale price arbitrage, but real-world dynamics may differ. EV owners may be willing to offer battery cycles at low cost as a secondary benefit of vehicle ownership, whilst dedicated battery investors require returns that justify substantial capital expenditure. How this competition plays out in practice remains uncertain. Nevertheless, the simulation results suggest that policymakers should consider V2G and stationary battery deployment as partially substitutable rather than purely additive. Aggressive simultaneous support for both could result in underutilisation of expensive infrastructure.

Investment Uncertainty in Flexibility Markets

The economic landscape for flexibility investments is characterised by significant uncertainty, though this should not be mistaken for a conclusion that flexibility is economically unviable. Several dynamics merit attention.

The competitive relationship between different flexibility sources creates interdependent business cases. An investor evaluating battery deployment cannot know with certainty how much competing flexibility, whether from other batteries or from smart-charging EVs, will materialise. If EV flexibility develops slowly, batteries could earn attractive returns. If smart charging and V2G become widespread, the same batteries face compressed arbitrage opportunities. This uncertainty is compounded by the fact that battery deployment and EV flexibility will evolve together: neither investors nor policymakers can simply assume a favourable scenario will persist. Moreover, this competitive dynamic operates across borders. A battery investor in Belgium is not only exposed to domestic EV flexibility developments, but also to flexibility deployment in the Netherlands, Germany, and France, which influences the cross-border price patterns that Belgian assets arbitrage against. Investment analysis conducted in purely national terms risks underestimating the sources of competitive pressure.

The simulation results suggest that long-duration batteries, such as the six-hour systems represented in the HIGH BAT scenarios, face particularly challenging economics when evaluated against wholesale arbitrage revenues alone. Even with ambitious renewable deployment and large inflexible charging loads, the resulting price volatility appears insufficient to recover capital costs of that magnitude. This finding is relatively robust across the scenarios examined, though it applies specifically to arbitrage revenues captured in wholesale energy markets.

However, several important caveats apply. Many real-world flexibility assets derive substantial value from revenue streams invisible to wholesale market simulations. Residential batteries and EV charging optimisation often earn their keep through solar self-consumption, which avoids electricity purchases that include substantial network charges and taxes. Commercial and industrial batteries frequently deliver value through behind-the-meter optimisation, peak shaving against capacity-based network tariffs, or participation in ancillary service markets. The Flemish capacity tariff, for instance, creates incentives for peak reduction that operate entirely outside wholesale price signals. In the 2030-2040 timeframe examined in this report, these alternative value streams may (still) prove important to justify flexibility investments even when wholesale arbitrage alone appears inadequate.

Similarly, the HIGH BAT capacity assumptions represent deployment levels that may not materialise precisely because of the weak economics the simulations reveal. Markets contain feedback mechanisms: if battery economics deteriorate, deployment slows, which in turn preserves value for batteries that are deployed. The simulation results should thus be understood as revealing the limits of how much flexibility the system can profitably absorb through arbitrage, rather than as predictions of what will actually be built.

A more confident observation concerns timing and sequencing. Early flexibility resources, deployed before competition intensifies, capture wider price spreads than later entrants. This first-mover dynamic creates incentives for early deployment, but also investment risk: early movers cannot know how quickly competitors will follow. For stationary batteries specifically, the simulations suggest that short-duration systems (two hours) face better economics than long-duration systems, as the additional energy capacity requires proportionally more capital whilst the additional arbitrage opportunities it enables are limited.

Belgium in the European Context

Belgium's position as a small, highly interconnected country in the heart of Europe fundamentally shapes how domestic flexibility resources create and capture value. The simulation results repeatedly demonstrate that cross-border dynamics influence Belgian outcomes as much as domestic choices.

Germany's scale dominates regional price formation. With renewable capacity measured in hundreds of gigawatts and battery assumptions reaching over 200 GW in HIGH BAT scenarios, German supply and demand patterns propagate through interconnectors to influence wholesale prices across neighbouring systems. Belgian flexibility resources operate within a price environment substantially determined by German conditions. Similarly, France's evolution from consistent net exporter toward potential net importer by 2040 would reshape the flows that Belgium has historically relied upon for supply security.

This international embedding has practical implications. Domestic flexibility investments do not operate in isolation; their value depends partly on what neighbouring countries deploy. If surrounding countries develop substantial flexibility, Belgian resources face stiffer competition for cross-border arbitrage. If neighbours lag, Belgian flexibility may export value through interconnectors. Neither outcome is inherently good or bad, but both differ from naïve analyses that treat Belgium as a closed system.

A related observation concerns how flexibility value "leaks" across borders in an interconnected market. Flexibility deployed in Belgium may help balance renewable variability originating in Germany or absorb French nuclear output during low-demand periods. The system benefits are real, but they accrue across the coupled European market rather than concentrating in Belgium alone. This is not a problem to solve but a reality to accept and manage. Belgium benefits enormously from interconnection, including security of supply supported by import capacity, but this integration means that purely national perspectives on flexibility value will necessarily be incomplete.

Environmental Co-Benefits

Flexibility deployment generates meaningful environmental benefits alongside the economic and operational effects discussed above. CO_2 emissions intensity declines systematically as flexibility increases, with Belgian electricity achieving roughly 12 to 21 percent lower emissions intensity in flexibility-rich scenarios compared to inflexible baselines. The mechanism is the displacement of gas-fired generation: when batteries and smart-charging EVs absorb renewable surpluses and discharge during peaks, they directly substitute for ramping services that gas turbines would otherwise provide.

These emission reductions represent what might be called a "no-regrets" benefit. The improvement arises purely from more intelligent use of existing resources, requiring no additional generation investment. However, it bears noting that Belgian electricity sector emissions operate within the EU Emissions Trading System rather than being subject to national targets. The emission reductions documented here contribute to European decarbonisation goals but do not directly affect Belgian compliance with any domestic obligation.

The magnitude of flexibility-driven emission reductions is largest in systems with high baseline carbon intensity. Belgium, with its substantial reliance on gas-fired generation for balancing (in 2030 and even in 2040), shows among the largest improvements. Countries with already-clean generation mixes (France with nuclear, the UK with offshore wind) show smaller absolute reductions, as there is less fossil-fuelled generation to displace. For Belgium specifically, the climate case for flexibility deployment is reinforced by these findings.

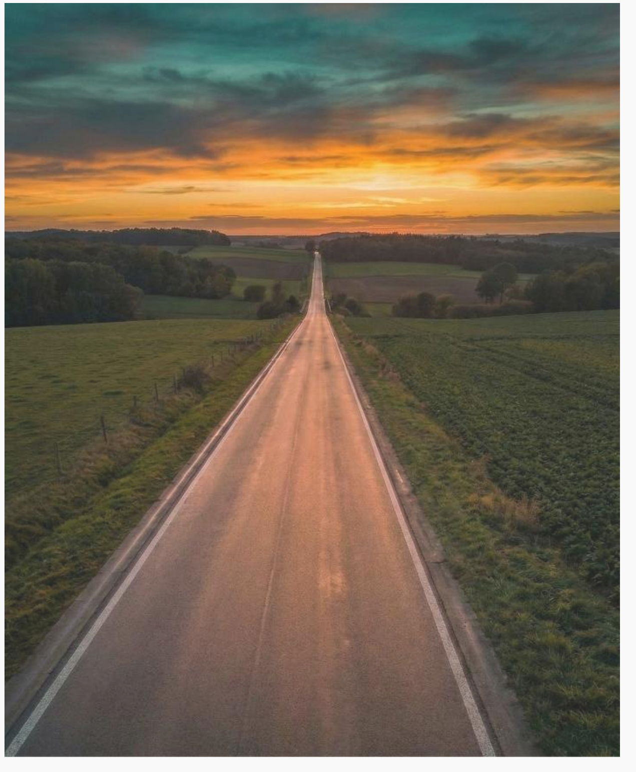
Implications for Policy and Investment

Several practical implications emerge from the analysis, though these should be understood as considerations for decision-makers rather than definitive recommendations.

For policymakers, the clearest priority is enabling smart charging infrastructure and market arrangements. The benefits are substantial, the costs are modest, and consumer acceptance barriers are lower than for bidirectional alternatives. The research and development needed to make smart charging work seamlessly at scale deserves sustained attention and funding. Beyond smart charging, policy should recognise that flexibility deployment creates distributional consequences. Consumer benefits are clear; asset owner returns are less certain. Support mechanisms may be needed to ensure socially valuable flexibility is deployed even when private business cases are marginal.

Regarding the relationship between stationary batteries and EV flexibility, the findings suggest caution about simultaneously pushing hard on both fronts. They compete for overlapping value pools, and aggressive support for both could result in expensive underutilised infrastructure. This does not mean choosing one over the other, but rather recognising their interaction when designing support schemes.

The international dimension warrants explicit attention in Belgian energy strategy. Domestic flexibility decisions interact with neighbour decisions in ways that affect outcomes for all parties. Coordination mechanisms, whether through regional market design or explicit policy dialogue, may improve collective outcomes compared to purely national optimisation.



For investors, the central message concerns uncertainty and conditionality. Flexibility economics depend on the broader flexibility landscape, which cannot be predicted with confidence. Business cases should be stress-tested against scenarios where competing flexibility is both scarce (favourable) and abundant (challenging). First-mover advantages exist but come with corresponding first-mover risks. Duration matters: shorter-duration batteries face better arbitrage economics than longer-duration systems, though other value streams may favour different configurations. And crucially, value stacking across multiple revenue streams may prove essential rather than optional: the simulation results suggest that in flexibility-rich futures, wholesale arbitrage alone appears insufficient to recover capital costs even at the lower end of projected 2030 and 2040 battery prices.

Concluding Observations

The analysis presented in this report reveals an electricity system in transition, where familiar assumptions about generation economics and market dynamics are being reshaped by the emergence of flexible demand and distributed storage. The competitive relationship between EV flexibility and stationary batteries, the erosion of conventional generator revenues, and the international interdependencies that shape domestic outcomes all represent dynamics that will intensify as the energy transition proceeds.

Yet the overall picture is not one of crisis or failure. The simulated systems function across all scenario variants; supply meets demand, prices form sensibly, and the transition toward lower-carbon electricity proceeds. The question is not whether flexibility can work, but how its costs and benefits will be distributed, which investment strategies will prove sound, and how policy can best facilitate efficient outcomes. These questions do not admit simple answers, but the analysis presented here offers a foundation for the informed deliberation they require.