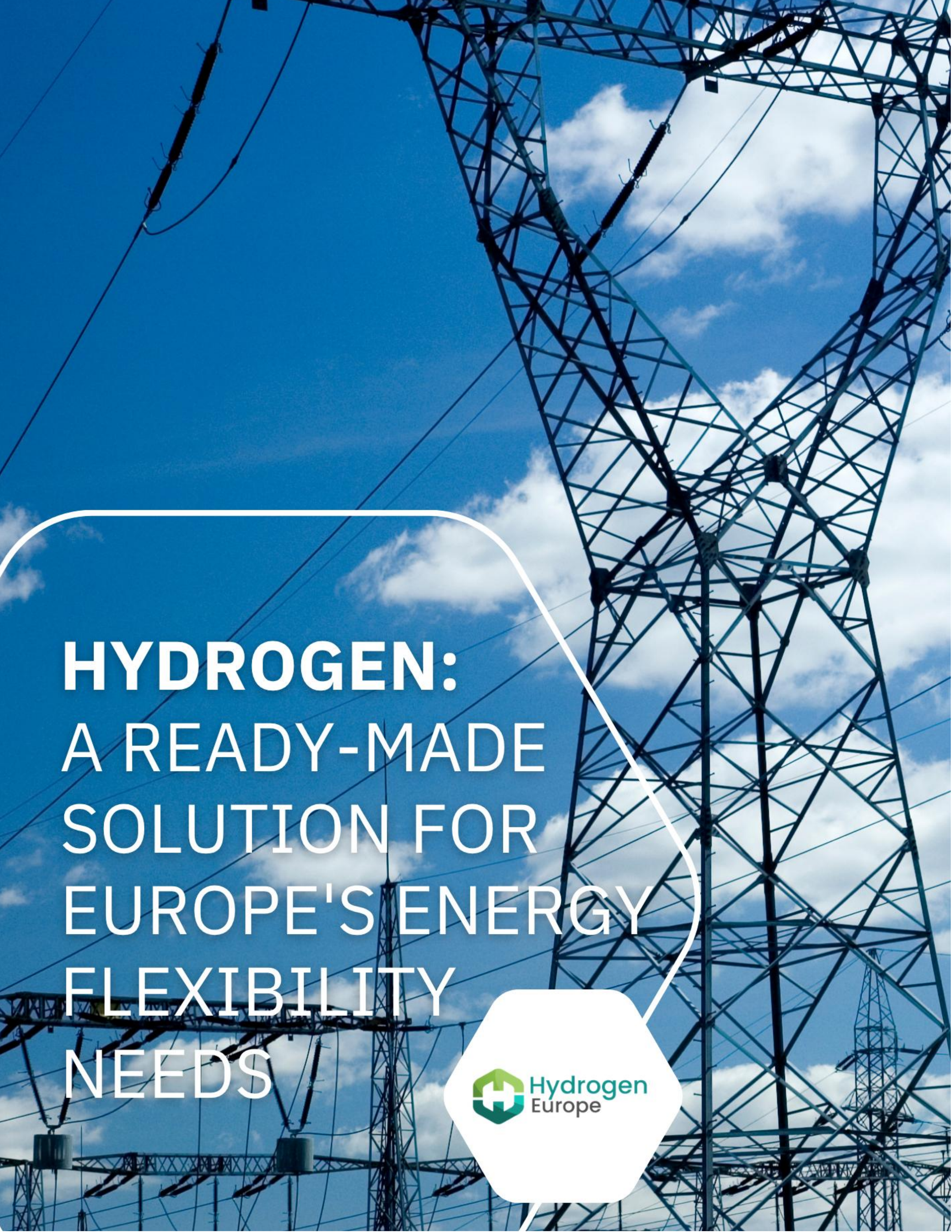

HYDROGEN:
A READY-MADE SOLUTION FOR EUROPE'S ENERGY FLEXIBILITY NEEDS

Hydrogen Europe

Executive summary

1. **Challenges in a decarbonised energy system**
    - Europe is facing increased electricity demand stemming from accelerating electrification of end uses and the emergence of new demand profiles (such as data centres).
    - Negative prices are undermining investment in renewables**:** Periods of oversupply are driving electricity prices to very low or negative levels, reducing project revenues and weakening investor interest. At the same time, natural gas evening price peaks are persisting, with a fivefold increase in price volatility since 2020.
    - Curtailment and redispatch are increasing at an unsustainable scale: In total, EU redispatch costs were €5.2 billion in 2022 and could be as high as €26 billion in 2030. By 2030, Europe could redispatch volumes equivalent to the annual electricity consumption of the Iberian Peninsula in 2024. Instead of being wasted, these volumes should be used to provide valuable homegrown clean molecules.
2. **Flexibility: An overlooked component in Europe's Energy Transition**
    - Given all of the above, the flexibility needs of our energy system continue to rise - The EU Agency for the Cooperation of Energy Regulators (ACER) has projected flexibility requirements to double by 2030, with significant seasonal flexibility needs.
    - Flexibility - the ability of an energy system to adjust both power generation and consumption in response to signals from the grid or the market – must be seen, now more than ever, as a main building block of an energy transition that will help Europe achieve energy sovereignty, affordability, and decarbonisation.
    - Although the EU has accelerated grid expansion and renewable deployment, there is no equivalent push for flexibility. There are no sufficient initiatives or instruments (beyond batteries for short-term storage) to enable flexibility, while gas power plants remain the main provider of flexible loads.
3. **Electrolysers are the most flexible load in the system**
    - Between 10 and 15 GW of grid-connected electrolysis capacity will be installed in Europe by 2030.
    - Electrolysers can participate in all grid services, ramping up and down within seconds, providing flexibility across different timeframes (from minutes to months).
    - Incentivising hydrogen demand-response can be faster and cheaper than massive grid expansion projects, which often face years of planning, permitting, and construction.
4. **The main barriers for electrolysers to act flexibly are not technological but systemic**
    - These constraints include a lack of market incentives and an absence of hydrogen infrastructure. Therefore, to unlock it, we recommend the following:
    - Build a market for clean flexibility: create clean flexibility markets through dedicated support schemes for storage and demand response. Flexibility markets should work across short, medium, and long timescales. Network tariffs should incentivise system-friendly behaviour without undermining industry competitiveness.
    - Prioritise grid access to Power-to-Gas units that are grid-friendly and favour greater flexibility of the system.
    - Remove regulatory barriers to flexible operation**:** Adapt the RFNBO framework so that electrolysers can respond to market signals without losing the value of certified green hydrogen. This includes keeping monthly temporal correlation rules, enabling access to front-of-the-meter batteries, and clearer rules for the participation in flexibility schemes.
    - Incorporate clear, measurable KPIs on flexibility and sector integration applicable to clean molecules, energy storage and demand-response alongside electrification targets in the post-2030 framework.
    - Accelerate hydrogen infrastructure: Hydrogen storage and transport infrastructure are the missing links to enable fully flexible operation of electrolysers. Europe needs faster deployment of hydrogen storage and pipelines, enabled by cross-sector infrastructure planning, and backed by demand-side support and risk-sharing tools that make projects bankable.

Contents

1. Objective of the paper

Flexibility is the ability of the power system to balance variable electricity supply and demand and keep the system running reliably across all market timeframes. **The aim of the paper is to showcase the technical and market potential for hydrogen production to behave flexibly** and contribute to the stability of the power system.

Electrolysers are not a conventional form of demand response: electricity demand traditionally has been very inelastic. But with the introduction of electarolysers in the system we are unlocking a new type of demand that is inherently elastic and thus capable of delivering flexibility. Most hydrogen production projects are designed to be flexible, responding to the variability of renewable energy sources (RES), helping maximise their integration and adapt to system needs. In fact, **electrolysers could become one of the largest sources of dispatchable demand in the European power system: around 15 GW of grid-connected electrolysis capacity could be installed in Europe by 2030**[1]**.**

The energy crisis of 2022 and the ongoing conflicts in the Middle East are once again a reminder to Europe on the importance of fostering homegrown renewable energy sources. Indeed, since March 2026, the European Union has faced an additional €24 billion in costs for fossil fuel imports in just 44 days[2]. Therefore, rolling out more RES is imperative to achieve energy sovereignty. However, the variable nature of RES requires proportional investments in flexibility (energy storage and demand response) to ensure the power system can adapt to their generation profiles.

Hence, **our focus should be directed towards finding new sources of non-fossil and homegrown flexibility**. This is particularily important with solutions such as **demand-side response,** which is **not only cheaper**, but **can be deployed much faster than large infrastructure projects**[3], which often require years of planning, permitting, and construction. Instead of only relying on building more batteries to fulfill today's challenges to meet demand when there is lack of renewables, reducing demand can be extremely beneficial in reducing fossil dependency – especially during peak periods when the grid is nearest its capacity.

This paper will explain the importance of flexibility and explore the technical characteristics of electrolysers, how market and regulatory design influences flexible behaviour, and what levers are needed to unlock their potential as the largest and most flexible demand response element in the power system.

2. Flexibility is the central challenge for Europe's energy system

a. Electricity grids investments must be paired with flexibility

The massive deployment of new or expanded power grids in Europe won't be enough to solve our energy challenges. While grid buildout is essential to delivering electricity to consumers, it is only one of several tools needed to achieve integration, affordability, and energy independence objectives[4]. **Investments in power grids must be paired with investments in flexibility to optimise grid usage and buildout**. Indeed, by adding even modest amounts of flexibility, the power system could significantly reduce grid expansion needs, reducing the financial pressure put on citizens and industrial electricity consumers.

---

[1] Hydrogen Europe, "Clean Hydrogen Monitor 2025", accessible here.

[2] Commission proposes actions to protect Europeans from the fossil energy crisis and accelerate the shift to clean, homegrown energy, accessible here.

[3] Cutting Peak Energy Costs with Demand Response, Environmental Law & Policy Centre, accessible here.

[4] These are the goals of successive EU energy and climate policies, including Clean Energy for All Europeans Package (CEP) — adopted 2018–2019; European Green Deal (2019); Fit for 55 Package (2021–2024); and the Clean Industrial Deal (2025)

Following the overarching objectives of electrification and RES integration, the EU has put forward and is still planning for many initiatives to incentivise the development of power grids such as the Grids Action Plan[5], the Grids Package[6] and upcoming Electrification Action Plan[7], as well as pieces of legislation such as the Energy Efficiency Directive[8]. **However, there are no similar and proportional efforts to promote flexibility.**

Today, most of power system's flexibility is provided by gas power plants[9]. **ACER expects flexibility needs to double already by 2030**, with important seasonal flexibility needs[10]. This challenge is increasingly recognised by policymakers and regulators: **ACER's identifies flexibility as the central challenge for Europe's energy system**[11].

b. Emerging power system challenges

i) High electricity grid investments and underutilisation

In 2024, Europe installed more than 77 GW of RES, with solar PV accounting for 84%. By 2030, Europe plans to have more than 1,200 GW of RES capacity[12], up from around 800 GW today[13] - implying annual additions of roughly 100 GW.

Currently, grid connections for RES are typically sized to accommodate peak generation, even though such peaks are only occasional and often coincide with simultaneous high renewable output across the system, **leading to price cannibalisation, grid congestion, and reduced market value for the electricity produced**. For instance, Solar PV has a capacity factor of 10% to 17% (approx. 875 to 1,500 equivalent full-load hours per year)[14], depending on location. Wind energy capacity factors range from 20-45% for onshore wind and even above 50% for offshore wind locations[15]. Given the non-dispatchable nature of RES and the partial overlapping of their production profiles, plus their low-capacity factors, for a significant share of the year grid infrastructure remains underutilised.

At the same time, **while Europe is underutilising parts of its electricity grid, grid expansion delays are also becoming a major bottleneck for the integration of new renewable and industrial projects**. Connection queues for renewables and industrial consumers can already span between 7 to 10 years[16].

To integrate the increasing number of renewables, **Transmission System Operators (TSOs) must build an equivalent amount of new grid capacity that should increase by 47% by 2030 and 144% by 2040**[17]. As a result, while we have lower network utilisation rates, we still have to massively oversize our electricity grid. This translates into higher costs that are passed down to electricity consumers with higher network tariffs. **Consequently, the grid costs share of the household electricity bill is expected to increase by 66% by 2050**[18].

---

[5] European Commission, "Communication on Grids, the missing link - An EU Action Plan for Grids", accessible here.

[6] European Commission, "Communication on the European Grids Package", accessible here.

[7] European Commission, Electrification, accessible here.

[8] EU/2023/1791, accessible here.

[9] ACER, "Key developments in EU gas and electricity markets – 2026 edition", accessible here.

[10] ACER & EEA, "Flexibility solutions to support a decarbonised and secure EU electricity system", accessible here.

[11] ACER, "Key developments in EU gas and electricity markets – 2025 edition", accessible here.

[12] European Commission, "Renewable energy targets", accessible here.

[13] IRENA, "Renewable capacity statistics 2026", accessible here.

[14] 5 things you should know about solar energy, European Commission, accessible here.

[15] Wind Europe, accessible here.

[16] EU guidance on ensuring electricity grids are fit for the future, European Commission, accessible here.

[17] CAN Europe, "EU Grids and the PAC scenario", accessible here.

[18] ACER, "Key developments in EU gas and electricity markets – 2026 edition", accessible here.

ii) Negative prices and unwanted “duck curve” dynamics

When the power system experiences an oversupply of RES, at times of low demand for energy, the electricity prices fall drastically. When coupled with the fact that **some generators may be willing to pay to remain online** - due to technical constraints, or high start-up costs - this leads to **negative prices**. In May and June 2025, some countries saw over 18% of hours priced below zero.[19]

Negative prices and renewable oversupply are also closely linked with a structural challenge in modern power systems: the so-called “duck curve”. This phenomenon emerges when high shares of RES – particularly solar PV – flood the system during periods of low demand (typically midday), followed by steep ramp-up in demand for electricity in the evening, precisely when generation from solar PV falls down - driving electricity prices up. This is reflected on the electricity market in higher price volatility, and the number of hours in which gas becomes the price-setting technology that keeps rising. ACER confirmed that record solar capacity in 2025 increased price volatility: daily price swings have increased 5-fold since 2020[20].

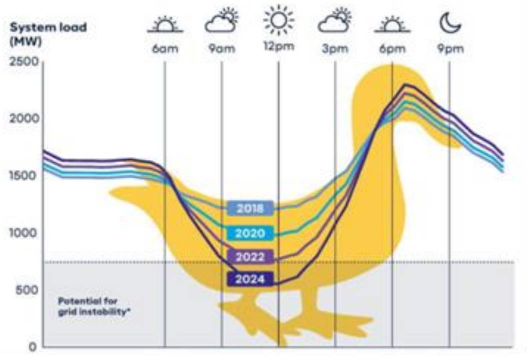

Figure 1: Duck curve: Net load not covered by solar. Source: ACER

As a result, TSOs face a dual operational challenge:

1. Very low or negative prices.
2. Local grid congestion, where available network capacity is insufficient to transport electricity to where it is needed.

To manage this imbalance, TSOs can implement two strategies:

1. **Curtailment of renewable generation**, reducing output from wind and solar plants, potentially paying a predetermined compensation price.
2. **Redispatch:** the TSO orders a plant downstream of the congestion to increase generation. These units are often fossil-based and are brought online at high cost[21].

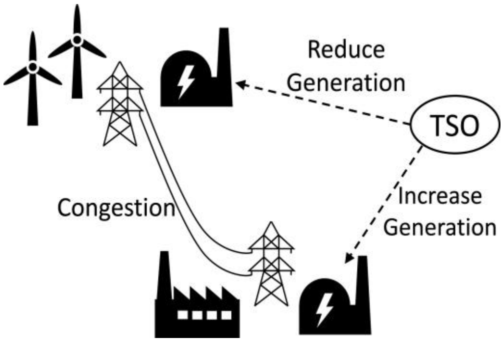

Figure 2: Schematic of congestion management.

The International Energy Agency (IEA) highlighted that **RES curtailment volumes increased roughly by 55% in 2024[22].** Meanwhile, according to the JRC, **up to 310 TWh of renewable generation could be**

---

[19] PV Magazine, Negative price hours rise in Europe, accessible here.

[20] ACER, “Key developments in EU gas and electricity markets – 2026 edition”, accessible here.

[21] This way, the congestion is alleviated without affecting the power balance. Source: Identifying drivers and mitigators for congestion and redispatch in the German electric power system, accessible here.

[22] International Energy Agency (IEA), “Renewables 2025: Analysis and forecast to 2030”, accessible here.

redispatched due to grid limitations in 2030 in a business-as-usual grid expansion scenario[23]. This would be equivalent to curtailing as many RES as the yearly energy supply to the Iberian Peninsula of 2024[24]. Even in the extreme grid expansion (XGE) scenarios (below), total redispatch volume would increase almost six-fold by 2030, curtailing 100 TWh of renewable generation.

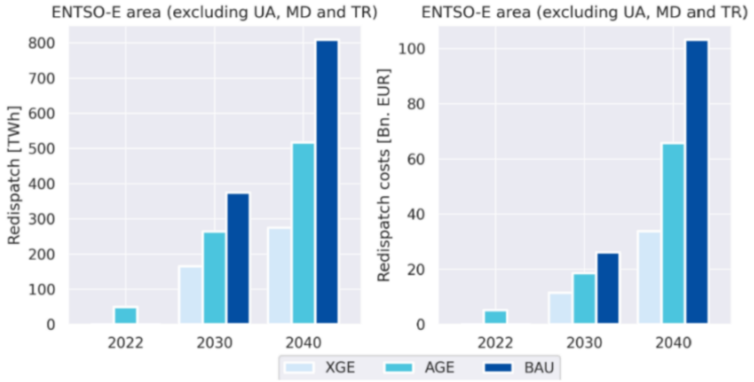

Figure 3: Redispatch volumes and costs for ENTSO-E area (excluding UA, MD and TR).
Note: XGE: Extreme Grids Expansion, AGE: Average Grid Expansion, BAU: Business As Usual.

In summer 2024, EU wind and solar contribution was particularly strong during daylight hours. As a result, reliance on fossil power has fallen quickly during daylight hours but remained relatively high during early mornings and evenings. In Germany, for example, the average share of fossil generation at 1 PM in the month of July almost halved from 36% in 2021 to 20% in 2024, whereas the share of fossil generation at 8 PM only went from 47% to 44%[25]. This illustrates that **natural gas still provides most of the system's flexibility, particularly at seasonal and evening peak times**. The need for alternatives is therefore clear if we are to seriously decarbonise our energy system.

iii) Increasing needs for ancillary services

The system operators need to balance generation and demand in real-time, 24 hours a day, 365 days a year. **With more variable generation, keeping a stable system in real time becomes more challenging. Therefore there's a growing need for Ancillary Services (AS),** which are required to maintain grid stability and security[26] - through technical restrictions and balancing services. **There is a correlated increase of AS costs in the months with a higher percentage of RES** – as there is a higher number of services reserved through the AS market than in a month with lower RES percentage[27]. As a result, AS are evolving from a marginal cost component (~2–3%) to a non-negligible share of electricity prices (5–10% and higher in stress periods)[28]. In Spain[29], for instance, the cost of AS accounted for 15% of the average final electricity price in 2024, amounting to 2.7 billion EUR – up from 10.7% in 2023[30].

---

[23] Joint Research Centre (JRC), "Redispatch and Congestion Management – Future-proofing the European Power Market", accessible here

[24] Spain, REE, accessible here (248 TWh). Portugal, AICEP, accessible here (52,42 TWh)

[25] EMBER, "EU battery storage is ready for its moment in the sun", accessible here

[26] The TSOs organise AS tenders to ensure the uninterrupted supply of electricity. Procuring AS help guarantee the instantaneous balancing between injections and withdrawals.

[27] REE, Impact of the ancillary services on the final price, accessible here.

[28] Cornell University, "Who should pay for frequency-containment ancillary services? Making responsible units bear the cost to shape investment in generation and loads", accessible here.

[29] The cost of ancillary services in high PV penetration scenarios: the case of Spain, accessible here.

[30] The impact of ancillary services on the average final energy price was €11.43/MWh, higher than the €10.73/MWh registered in 2023. REE, Impact of the ancillary services on the final price, accessible here.

The impact of AS is not only monetary but also environmental: as they are predominantly provided by combined-cycle gas turbines (CCGTs), they are associated with high CO2 emissions and continued fossil fuel dependence. This could potentially mean that **rising AS needs will reinforce short-term reliance on fossil generation unless other clean flexibility alternatives are deployed**.

iv) Rising power system costs

When curtailment occurs, the operator of the RES power plant is compensated for the energy that cannot be sold on the market due to curtailment – a common practice in most EU Member States[31].

With the explosion of negative prices and curtailments, the TSOs are forced to implement an increasing number of measures to address this issue including the above mentioned redispatch, but also congestion management, balancing services, procurement of ancillary services, and building more grids. **These measures increase overall system costs, which are ultimately passed on to consumers through higher electricity prices.**

Recent national examples illustrate the scale of these costs:

- In the United Kingdom, £380 million were paid in 2025 to compensate wind farm operators for switching off production, and the cost of replacing that wasted wind with gas-fired power grew to £1.08 billion[32].
- In Germany, €554 million were spent on compensation to RES generators, and the cost to redispatch, largely involving payments to dispatchable plants such as fossil-fuelled generators, rose to €1 billion– bringing the total cost of balancing and ancilliary services to €2.3 billion in 2023[33].
- In total, EU redispatch costs were €5.2 billion in 2022 and could be as high as €26 billion in 2030[34].

These payments are passed down to energy consumers through the electricity bill. As RES operators are compensated for their curtailed energy, this does not incentivise them to store, convert, or otherwise utilise surplus electricity. **Instead of using these payments to invest in solutions that could deliver value to society (flexibility or/and energy storage), Europe is reinforcing the vicious cycle that keeps European energy consumers reliant on fossil-based and expensive dispatchable generation**.

Reinforced flexibility measures could help alleviate those rising financial burdens. Even if Member States would increase the state support to flexibility solutions – alongside regulatory incentives – in the long term, these "anticipatory" investments will result in more affordable energy prices, less dependency on fossil imports, and better RES integration - and thus quicker decarbonisation.

There are many solutions that can be supported at national level to increase flexibility: energy storage systems, demand-side flexibility (demand response), flexible generation, grid interconnections, and sector coupling. **This briefing focuses on hydrogen production (through electrolysis)** that falls into several of the above-mentioned categories and can help address several of the challenges outlined above.

For instance, through Power-to-X, electrolysers and hydrogen infrastructure deployment can reduce pressure on rolling out new electricity-based flexibility solutions, notably batteries, by delivering a significant share of flexibility needs.

---

[31] Mandated under Article 15 of the Electricity Market Design Regulation.

[32] Wind Curtailment Costs Hit £1.5bn: "Why UK Wind Farms Get Paid to Switch Off – and How to Fix It", accessible here

[33] "Identifying drivers and mitigators for congestion and redispatch in the German electric power system", accessible here.

[34] European Commission, "Report on the State of the Energy Union 2025", accessible here.

A recent study by FfE based on detailed European system modelling, shows that **hydrogen deployment enhances system efficiency by absorbing surplus renewable energy** (with >85% of electrolysis occurring during excess generation periods), **reducing electricity-based flexibility needs by ~30% by 2050** and alleviating pressure on electricity grids[35].

The next chapter focuses on practical aspects of how electrolysers can provide those services.

3. Flexibility services from electrolytic hydrogen production

a. Realistic technical capabilities of electrolysers to adapt to system needs

i) Variable load ranges of operation

Grid-connected electrolysers can all modulate their electricity consumption while in operation within a certain range – starting from minimum operating power between 10% - 40%[36] (depending on project and technology) and **increasing up to 110% of nominal power – quick enough to participate in nearly all grid and flexibility services**. The remaining 60 – 90% of their electricity consumption can therefore be adjusted, enabling substantial flexible demand that can respond to system needs. Should the system be very stressed, it is possible to turn off the unit for a few hours, and then proceed with a cold start-up – with the caveat that interrupting operation may impact the ageing of the system to a certain degree[37].

Also, overloads (going above nameplate capacity) above 100% become technically and economically feasible mainly at larger scales, where the additional CAPEX for upgraded power electronics and balance-of-plant can be justified[38]. They can be achieved for a short time window – followed by a mandatory lower power cooling period. It is intentionally utilized to capitalize on "peak" power from wind or solar that exceeds the electrolyser's nominal rating, further reducing the need to curtail (waste) energy[39]. This can also be used to contribute to grid stability, by drawing excess power to mitigate overvoltages in the grid during periods of high renewable generation.

Electrolysers are not only the most elastic load in the power system, but **it is cheaper and easier to pool capacity for demand response between several electrolyser installations than coordinating millions of EVs or heat pumps** distributed across Europe. The average size of projects increased from around 3MWel in 2024 to around 10MWel in 2025. Overall project sizes keep on increasing with the first two >50 MWel becoming operational in 2025, and the first 200MWel coming into operation in 2026.

ii) Dynamic response ranges

- **Start-up times:** warm start ups[40] can range between 1 and 10 minutes, depending on the technology. Cold start ups[41] vary from 10 mins in the case of PEM, to ~1 hour for Alkalyne electrolysis[42].

---

[35] FfE (2026): Unlocking Energy System Efficiency: The Strategic Role of Hydrogen Infrastructure in Sector Coupling. Study commissioned by Gas Infrastructure Europe (GIE), accessible here.

[36] Heavily dependent on technology, but even the least flexible units can reduce their consumption to 40% of Pmax. However, most average values are between 10 – 20% of minimum nominal power consumption.

[37] IRENA, Green Hydrogen Supply: A Guide to Policy Making, accessible here.

[38] A review of electrolyser-based systems providing grid ancillary services: current status, market, challenges and future directions, accessible here.

[39] Economics of renewable hydrogen production using wind and solar energy: A case study for Queensland, Australia, accessible here.

[40] Initiating production when the unit has been recently turned off or in standby, allowing it to utilize stored thermal energy to reach operating temperatures faster than a cold start.

[41] Initiating hydrogen production when the system is initially off, at ambient temperature, and often depressurized, typically after a long period of inactivity.

[42] Thermal Analysis and Optimization of Cold-Start Process of Alkaline Water Electrolysis System, accessible here.

- **Ramp rates:** large-scale industrial systems typically feature ramp-rates – the change in power output of a demand unit as it is ramping up or down – of 1-10 %/s[43] - depending on technology and size – once operating conditions are reached, allowing near-instantaneous response to grid signals[44]. Small-scale systems can achieve even higher ramp-rates[45].

These capabilities are demonstrated across different electrolyser technologies. Both PEM and alkaline electrolysers, can meet the ramping requirements needed to participate in Automatic Frequency Restoration Reserve (aFRR) markets, which require full activation within five minutes following the signal and delivery of 90–110% of the requested power.

iii) System Services that electrolysers can participate in

Electrolysers can provide flexibility across multiple timescales, ranging from fast ancillary services to longer duration through hydrogen storage. The table below summarises the main services electrolysers can provide, the corresponding markets, and the potential system value:

Elements	Grid services	Daily	Weekly	Long Term
Services	Fast load modulation Turn-down capability	Turn up / down Dispatchable demand	Curtailment absorption Peak shaving Congestion relief	Long-duration storage (H2) Firm demand reduction
Markets	FCR, aFRR, mFRR Ancillary Services & Balancing services	Flexibility support schemes	Congestion Management Flexibility support schemes	Capacity Mechanisms System adequacy
System value	Frequency stability Reduced fossil ramping	Lower balancing costs, reduced redispatch	Deferred grid reinforcements, reduced curtailment costs (and less energy waste)	Security of supply System resilience
Load factor	Flexible operation around a dynamic setpoint (typically 50–90%)	Medium load factor with daily modulation (40–80%)		High utilisation rates possible with H_2 storage and infrastructure (>85–95%, excluding maintenance)
Barriers	Limited market access, lack of aggregation frameworks	Limited price arbitrage opportunities for RFNBOs, restrictive temporal correlation rules, insufficient market incentives for demand response.		Lack of hydrogen storage and infrastructure, no incentives for decarbonised capacity mechanisms, fragmented cross-sector planning.

---

[43] VDE VERLAG, "Possible Contributions of Electrolysis Systems to Grid Stability", accessible here.

[44] The reason is that large industrial systems are subject to additional effects and measures, such as cycling times of plant controllers, self-check functions before system start-up, consideration of process side reaction and plant control times, and adjustment of significant mass flows (water intake, cooling, gas output, and gas handling for downstream processes).

[45] However, it is worth noting that thermal management must follow the load change. Also, gas crossover risks increases when the electrolyser operates at partial load.

This multi-timescale flexibility makes electrolysers uniquely positioned to complement other flexibility technologies such as batteries, which are typically optimised for short-duration services.

Focus: Batteries - strengths and shortcomings in addressing flexibility

Batteries will naturally play a crucial role in handling short-term flexibility needs in the power system. Indeed, the rising volatility is incentivising the massive installation of utility-scale batteries: it is expected to exceed 160 GW by 2030 in Europe (10-fold increase from 2021 levels) [46].

Most operating utility-scale batteries[47] in Europe have been designed for 1-hour to 2-hour durations, providing services like frequency response and intraday trading[48] - very short-term flexibility operation. Still, the market is rapidly moving toward 4-hour durations, which are expected to make up more than 60% of total installations by 2050[49].

However, only around 60% of the nameplate capacity is usable daily: batteries should neither be fully discharged nor charged to 100%, as this degrades their lifespan. In practice, the recommended range of operation is 20% to 80%. Moreover, to achieve profitability batteries aim to have at least one cycle per day[50] - with some modern installations that can manage multiple cycles daily for revenue optimization.

While batteries are extremely effective in smoothing evening ramping requirements—by storing low-price midday electricity generated by solar PV—they cannot fully cover demand beyond the peak hours. Other forms of long-term storage or demand response are therefore needed to supply the remaining nighttime hours, particularly during winter periods with low solar output and high evening demand.

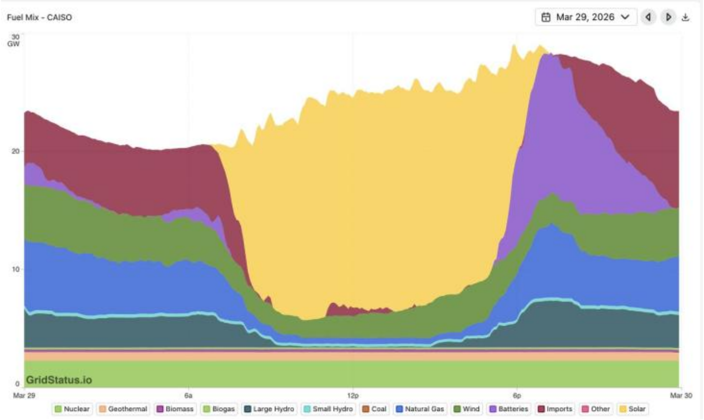

Figure 4: Example - CAISO Fuel Mix on the 26th of March of 2026. Source: CAISO[51]

In the picture above, an example of California's Independent System Operator (CAISO) where batteries were able to absorb most of the evening peak but still imports had to cover the residual load in the remaining night-time hours until solar starts delivering power again.

Therefore, **while batteries will excel at intra-day arbitrage and in the provision of fast-response grid services, their constraints to deliver several cycles per day and short injection timeframes mean they fail to address the need for flexibilities at longer timeframes** (from +4 hours to days, weeks and seasonal flexibility).

---

[46] European Commission, "Key facts on energy storage", accessible here.

[47] Utility-scale (>10 MW) battery storage are projects directly connected to electricity transmission systems, or the grid, i.e. front of the meter assets.

[48] EMBER, "EU battery storage is ready for its moment in the sun", accessible here.

[49] Aurora Energy Research, accessible here.

[50] A full cycle represents 100% discharge, which can be spread across multiple smaller bursts rather than one daily depletion. For instance, Tesla Megapack offers a warranty of 15 years and 10,000 cycles = 1,09 cycles per day.

[51] CAISO Fuel Mix, accessible here.

Also, while batteries are likely to absorb most of the Auxiliary Services market[52] (mainly due to the high volumes at which they are expected to be rolled out), electrolysers are also perfectly capable of participating in this market[53]. Indeed, electrolyser facilities are already producing RFNBO-certified hydrogen while participating in AS[54].

Finally, in some instances electrolysers are used by generators, such as hydroelectric power plants, where instead of frequently ramping up and down the generators, the electrolyser can utilize excess power. This reduces the need for mechanical adjustments, lowering wear and tear on the turbine units and associated equipment, while helping to balance the grid [55].

b. Market driven flexible operation

Flexibility is a core feature of electrolysis technology, since economic incentives discourage electrolysers from producing hydrogen when electricity prices are high. Electricity costs are around two-thirds of the Levelised Cost of Hydrogen (LCOH)[56], and any price of electricity above €60/MWh makes it economically unattractive to produce hydrogen as the LCOH would be around €6 – 9/kg of H_2 [57]. With grey hydrogen prices at €2 – 3/kg of H2, the only way for green hydrogen to become more competitive is to absorb the cheapest electricity prices. This makes them inherently well suited to act as flexible demand, absorbing excess renewable and low carbon electricity and supporting system balance.

For instance, in some cases, inflexible generation units such as nuclear power plants are incentivised to install hydrogen produciton units behind the meter to produce hydrogen when prices are low – instead of bidding at negative or ultra-low prices – thereby unlocking additional revenue streams[58].

i) Hydrogen production is not a base-load demand

Both from a technical and an economic point of view, there is little incentive to run electrolysers in a based-load mode. First, it can be a lot more attractive to resell the contracted renewable electricity during times of increased demand and high electricity prices[59]. As seen in the example below, as the utilisation rate of electrolysers increases, the LCOH decreases up to a certain point (amortizing the high CAPEX), and then increases again as it starts to run more and more during peak hours.

Second, operating continuously at high load factors can accelerate cell degradation, shortening stack lifetime and reducing the overall value of the asset.

---

[52] Ancillary service prices 'through the roof' in Baltics, 20-30% IRRs for BESS first-movers, accessible here.

[53] European Commission -H2ME 2, D4.8: Assessing the current role of electrolysers in the provision of grid services Shane Slater, Michael Joos, Freddie Barnes, Fabian Bräuer, Alexander Fish, accessible here.

[54] For example, see Everfuel's HySynergy plant: accessible here.

[55] Nel ASA: Receives a USD 7 million purchase order for PEM equipment to be deployed in the US, accessible here.

[56] The Levelized Cost of Hydrogen (LCOH) is the average, discounted cost per kilogram of hydrogen produced over a project's lifetime, covering capital (CAPEX) and operating (OPEX) expenses. It is used to compare the competitiveness of different hydrogen production technologies (e.g., green vs. grey).

[57] Clean Hydrogen Production Pathways Report 2024, Hydrogen Europe, accessible here.

[58] See: Nine Mile Point Begins Clean Hydrogen Production, US DOE, accessible here or the Nuclear-Powered Hydrogen Cogeneration project here.

[59] Upcoming implementation of RED III may improve the competitiveness of renewable hydrogen (those countries with penalties of around 14 EUR/kg of grey will allow those RFNBOs of prices of 11 EUR/kg of RFNBO to find their way in the market). Despite these incentives, cost optimisation will still remain strongly linked to the ability to access low-cost electricity and operate flexibly.

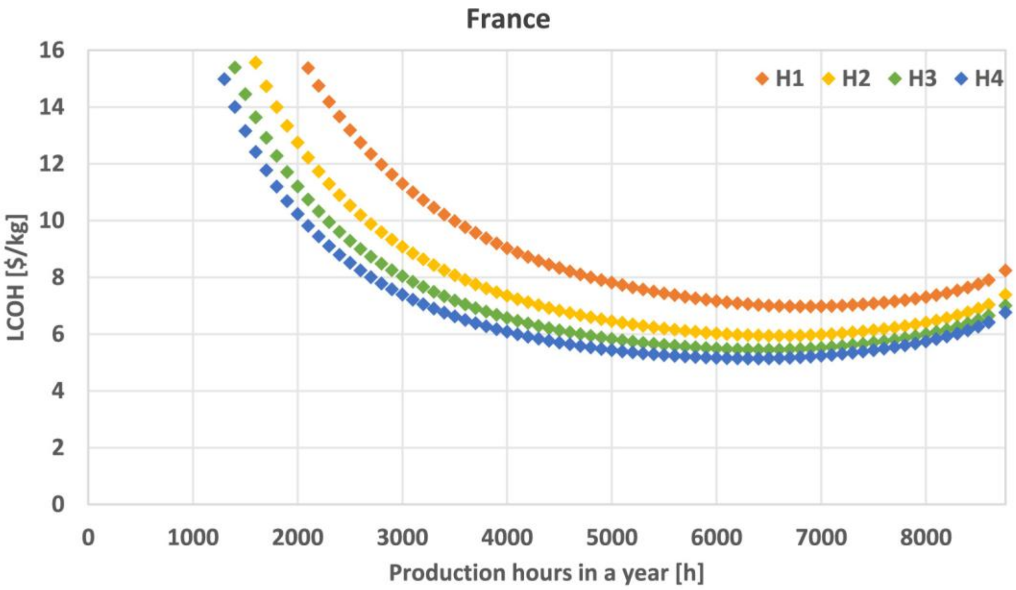

Figure 5: LCOH computed for France for various CAPEX levels [60]

ii) Regulatory constraints regarding renewable hydrogen production

Under the Delegated Regulation (EU) 2023/1184, **to qualify as Renewable Fuels of Non-Biological Origin (RFNBOs), hydrogen producers are mandated to source their electricity through renewable Power Purchase Agreements (PPAs)** – with very limited exceptions. Therefore, there are hardly any electrolyser facilities operating without a secured PPA, which includes both financial hedge and physical delivery. In addition, **RFNBOs are obliged to comply with additionality (from 2028 onwards), temporal correlation (hourly as from 2030) and geographical correlation**.

A transition towards hourly temporal correlation will limit the ability of the electrolyser to always behave in a system-friendly manner. Instead of optimising its operation based on electricity spot prices (and hence respond to the varying demand and availability of low-cost renewables), it will closely follow the availability of renewable power from the contracted PPAs (from single, individual power plants) [61].

Article 6 of DA 2023/1184 contains a provision that temporal correlation requirement is to be relaxed for cases where the price of electricity on the market falls below 20 EUR/MWh (or 0.36 times the ETS allowance price). However, the feedback from project developers suggests this rule is nearly impossible to integrate into a bankable business model:

1. Firstly, it requires relatively good visibility on the quantity of hours during the year where such conditions might occur, superimposed with the project's own production profile. Performing such an analysis for the 20-year project planning horizon is difficult to perform accurately, for obvious reasons.
2. Secondly, the share of these hours in the total power purchase volumes is currently below 2% for most hydrogen production operators - but expected to increase due to the rise of negative and ultra-low prices.

---

[60] V. S. Atay et al., "Assessing the role of flexibility in a carbon-neutral European power system", *Energy*, accessible here.

[61] For instance, if the PPA is signed with a PV plant, the RFNBO plant will not be able to consume electricity during the night, even if there is an oversupply of wind energy (little demand) and the TSO is forced to dispatch downward some wind parks. This is fully explained in Hydrogen Europe Impact assessment of the DA, accessible here.

Contrary to concerns about increased system emissions, monthly correlation is more effective at reducing CO2 emissions than hourly correlation[62]. For the purpose of reducing CO2 emissions, there is little difference between purchasing the renewable electricity on the spot market of the energy exchange or through PPAs.

Under a monthly correlation framework, hydrogen producers would sell their PPAs during high-price (and typically higher-carbon intensity of the electricity mix) periods and shift hydrogen production to periods of low prices and high renewable availability[63]. Under hourly correlation, however, this isn't possible as hydrogen producers are compelled to strictly follow the hourly profile of the contracted PPA.

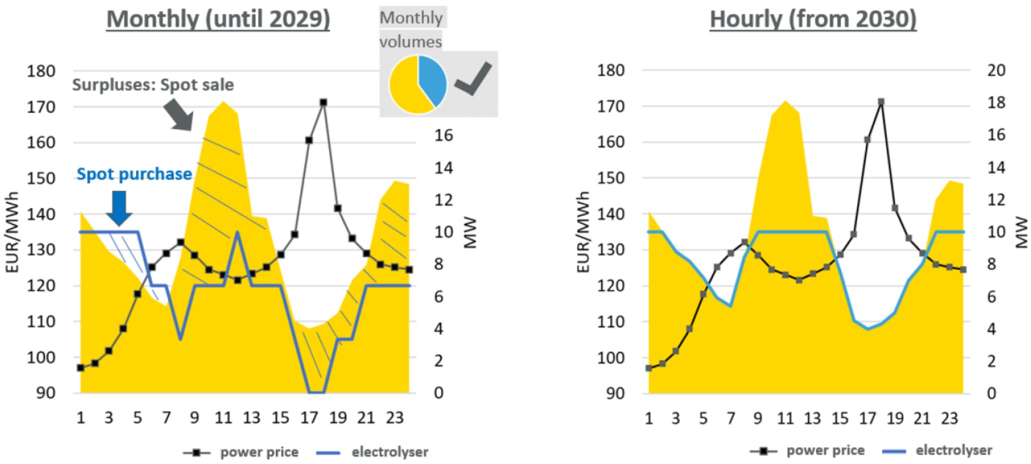

Figure 6: Dispatch comparison of a 10-MW electrolyser with monthly price-optimised and hourly simultaneity[64]

The correlation between monthly correlation and reduced emissions is shown in the figures above, with the hourly CO2 intensity being approximated by the hourly share of renewable energy in the load. This is backed up by the results of the study "*System-friendly integration of green hydrogen*" commissioned by the German Federal Ministry for Economic Affairs and Climate Action[65]. The authors concluded that a market-oriented operating mode of electrolysers is already sufficient to reduce CO2 emissions. Indeed, **when Demand Side Response (DSR) is implemented with a market-based approach, even small amounts of demand response can displace the most expensive (and usually more polluting) peaking units**. Simplicity of regulatory framework is also an added value as it streamlines the certification process.

iii) Barriers to adapt to Dynamic Network Tariffs

Beyond certification requirements, regulators are increasingly including time-of-use elements in network tariffs to enhance system-friendly operation[66]. Such system-level signals correlate more closely with electricity prices than with any specific PPA profile. However, due to the RFNBO criteria outlined above, hydrogen operators may be unable to follow these time-based signals if they do not align with the hourly contracted PPA volumes. As a result, **electrolysers may be unable to benefit from reductions in grid charges that are essential for their business case**, thus limiting their ability to fully provide system-friendly flexibility.

---

[62] E. Zeyen, I. Riepin, and T. Brown, "Temporal regulation of renewable supply for electrolytic hydrogen", accessible here,

[63] This also holds for those countries with high coal intensity, like Germany and Poland.

[64] EWE, "Strombezugskriterien für Wasserstoff" (Criteria for purchasing electricity for hydrogen), Sept. 2024, accessible here.

[65] Ibid.

[66] Commission continues action to lower energy bills with new guidance on renewables, grids infrastructure and network tariffs, accessible here.

c. Operational constraints to flexibility

As the European hydrogen backbone is still in early development, electrolyser deployment is largely focused on grid-connected sites near industrial hubs. In this transitional stage, electrolyzer flexibility remains primarily governed by **downstream processes** and **localized storage availability**:

Higher flexibility	• **Power & Heat generation**[67]: large power plants (e.g. combined heat and power plants or internal combustion generators), that may use hydrogen can deliver high flexible capabilitites. However, they would be expected to consume large quantities of hydrogen, requiring access to hydrogen pipelines. • **Road transport**: hydrogen refuelling stations with onsite generation can include storage buffers that allow flexible hydrogen production. In HRS supplied by tube trailers, there is a full decoupling between production and use, with the H2 stored in high pressure cilinders. • **Refineries (partial hydrogen switching):** refineries integrating clean hydrogen can maintain flexibility thanks to existing SMR-based hydrogen production[68], allowing them to switch between fossil-based and clean hydrogen, depending on availability.
Medium flexibility	• **Industrial heat**: facilities may temporarily switch to alternative fuels (e.g. natural gas) if hydrogen supply fluctuates. Furthermore, industrial heat processes / facilities often do not run continuously (e.g. seasonal food industry). Still, it is important to communicate to the industrial facility changes in hydrogen share, as the variation of the fuel in the combustion process may impact the properties of the final product. • **Ammonia plants:** the Haber-Bosch process remains inherently inflexible due to thermal inertia and the need for constant high pressures, requiring advanced control strategies to protect the catalyst during rapid changes. Flexibility is improved by separating hydrogen production from Haber-Bosch synthesis, allowing hydrogen storage (e.g. in pipe or cavern) to act as a buffer for the ammonia reactor. Therefore, flexiblity is achievable only by switching the source of hydrogen[69].
More rigid hydrogen demand	• **E-fuels and synthetic fuels production**: hydrogen consumption can be modulated to some extent, but process constraints (minimum loads, ramp limits, and process stability) may limit operational flexibility. These processes typically have slower dynamics compared to electrolysers, meaning that additional hydrogen storage or buffering may be required. • **Clean steel (DRI-based processes):** hydrogen demand shows limited short-term flexibility due to the continuous nature of steel production and process stability requirements. However, some intermediate flexibility may be possible depending on plant design and storage integration, placing the sector between highly flexible and rigid demand profiles.

---

[67] Stadtwerk Hassfurt uses highly innovative CHP unit: For the first time, a hydrogen-based and zero-CO2 storage network has been created for regenerative electricity for communal use, accessible here.

[68] As long as the unit keeps the SMR system, since it can be costly to keep it if not needed anymore after a while – this is not for the immediate transition phase but for a more advanced future.

[69] The Skovgaard/Topsoe dynamic green ammonia production unit, features high flexibility and responsiveness albeit compared to gas, using atmospheric alkaline, accessible here.

Given Power-to-Gas units' ability to behave flexibly that is not only dependent on concrete operational constraints but, more importantly, on the market and regulatory conditions, the next chapter will focus on concrete recommendations to help actualise hydrogen potential.

4. Policy Options to unlock hydrogen flexibility

a. More flexibility market incentives

Electrolyser are very price-sensitive, and any additional incentives would further unlock even more flexibility capabilities. This is not only the case for hydrogen, but also – and even more critically – for other demand types such as data centres that are more inelastic[70]. Therefore, better designed market mechanisms to promote flexibility are not only needed for hydrogen production, but also for other **industries and new loads that are being integrated into the power system.**

Focus: The EU Flexibility Framework is not enough to incentivise flexibility

The Electricity Market Design Reform (EMDR) approved in 2024[71] introduced non-fossil flexibility support schemes (allowing Member States to implement them alongside or instead of capacity mechanisms) to incentivize price signals for short-term flexibility services like demand response and storage[72].

Yet, at least 10 Member States (MS) are only in the early implementation stages of non-fossil flexibility support schemes[73] while their flexibility needs are on the rise. Still, even if fully implemented, these mechanisms are focusing only on short-term flexibility, reserving seasonal flexibility to natural gas since there are not EU-wide incentives to decarbonise capacity mechanisims.

Moreover, by June of 2025, MS must have assessed their Indicative National Flexibility Objectives. This exercise has been, once again, delayed.

The European Commission could implement a Union Strategy on Flexibility (with no deadline forseen for its implementation in the legislation). Due to the accumulated delays, that Strategy is likely to come way too late to address the current challenges of the power system – which is particularly alarming given the energy crisis the EU is going through.

Member States should:

- **Rapidly implement non-fossil flexibility support schemes that reward clean flexibility solutions**, including hydrogen, energy storage and demand response, while ensuring they are compatible with RFNBO certification.
- **Design flexibility markets across multiple timescales**, enabling technologies that can deliver flexibilities across different timeframes to participate in them and/or add provisions for the decarbonisation of Capacity Mechanisims to incentivise other forms of clean energy to participate.
- **Enable hydrogen to unlock the available flexibility** and grid services revenues, by allowing and encouraging **hydrogen production facilities to participate in the ancillary services tests** on equal footing as conventional generators.

The European Commission should:

- **Rapidly adopt and implement the Union Strategy on Flexibility** to accelerate the deployment of flexibility solutions across the electricity system. It should be accompnaied by a legislative proposal.

---

[70] Energy Monitor, Challenges and Opportunities for the Energy Sector as Data Centres Boom, accessible here.

[71] Electricity Market reform (Directive (EU) 2024/1711 and Regulation (EU) 2024/1747)

[72] ENTSO-E, "Definition of the type and format of data and the methodology for the analysis by transmission system operators and distribution system operators of the flexibility needs at national level", accessible here.

[73] ACER Security of Supply, 2024 Monitoring Report, accessible here.

- Incorporate **clear, measurable KPIs on flexibility across different timeframes and sector integration** applicable to clean molecules, energy storage and demand-response, in parallel with the KPIs proposed for electrification on the upcoming Energy Security revision and/or the Electrification Action Plan. The future post-2030 framework could serve as the appropriate vehicle for this as well.
    - These indicators should go beyond capacity targets and focus on concrete impacts, such as reducing renewable curtailment, providing flexibility services (demand response and peak management), and aligning with renewable integration objectives.
    - They should also reflect real system signals, including grid congestion, negative price periods, and curtailment levels, in order to capture actual system performance.

b. Better designed grid tariffs

As discussed in the Section "*Barriers to adapt to Dynamic Network Tariffs*", many regulators are introducing dynamic network tariffs to further incentivise flexibility. However, moving directly to full dynamic network tariffs carries high uncertainty and risks - adding to existing investment barriers.

Regulators & Member States =-

[hould:

- In the upcoming legal proposal on network charges and taxation (as announced in the recent Communication AccelerateEU[74]), the MS that wish to implement dynamic tariffs should be guided towards introduction of **a base or ceiling tariff with discounts, instead of implementing fully dynamic network tariffs.** The discounts would be applied when network users—such as Power-to-X facilities—demonstrate system friendly behaviour.
- **Introduce targeted reductions or exemptions from grid tariffs for flexible assets**. Member States should recognise electrolysers (or Power-to-Gas units) as its own category of network users under Directive (EU) 2019/944 and exclude them from grid fees, reflecting their contribution to system flexibility and RES integration.
- **RFNBO units should be exempt from charges linked to certain environmental and public policy-derived taxes or levies**, as they present positive externalities that are contributing to EU and national climate objectives through decarbonisation, reducing network needs, and enhancing renewable energy integration.

c. Priority grid access for flexible loads

Requests for grid connection are exceeding grid capacity across Europe. For instance, in Denmark there are currently 60 GWs of new projects waiting for grid connection, more than 8 times the peak Danish power needs (7 GWs at peak capacity)[75]. In Spain the situation is similar - with approximately 50% of connection requests denied. This has led to an estimated €60 billion in stalled projects[76]. As a result, **TSOs are introducing criteria to prioritise granting grid access to loads that are the most mature**[77]. However, **these criteria should also include those projects that deliver the highest benefits to society and are grid-friendly.** Introducing such market incentives will help to induce more flexibility.

---

[74] Communication AccelerateEU – Energy Union (COM/2026/370)

[75] Denmark faces data centre reckoning as power grid overwhelmed by surging demand, CNBC, accessible here.

[76] BBVA Research, Spain | The grids moment, accessible here.

[77] Commission notice, Guidance on efficient and timely grid connections, accessible here.

As a prime example, Spain has introduced a new Tier-based system[78], which prioritises Type 1 (housing and hydrogen and renewable gases), followed by Type 2 (industrial electrification and mining) and finally Type 3, which are data centres[79].

Member States & Regulators should:

- Prioritise grid access to projects that deliver the highest system and decarbonisation value and that are the most grid friendly.

d. A more flexible RFNBO framework and access to renewable surpluses

Alongside the challenges associated with temporal correlation, **the current RFNBO framework** (as definied in the Delegated Act (EU) 2023/1184) **prohibits the use of battery storage systems that are not behind the meter**. Access to utility-scale batteries is essential to ensure that large RFNBO producers can store surplus electricity[80].

Moreover, additionality rules prevent electrolysers from accessing electricity from state aid-supported and older renewable assets, limiting their ability to tap into the surplus RES generation coming from existing assets. This is particularly problematic in regions with structural renewable surpluses[81], such as northern Germany. As a result, with the current legislation, **hydrogen production can only help avoid worsening system imbalances, rather than actively reduce curtailment and provide system flexibility**.

European Commission should:

When revising the Delegated Act 2023/1184, the following elements should be taken into acount to unlock hydrogen flexibility:

- **Introduce a more flexible approach to temporal correlation requirements** that can preserve environmental integrity while allowing electrolysers to respond to system's conditions. We believe a monthly temporal correlation is optimal to reduce system's CO2 emissions and promote grid friendly operation.
- **Allowing for the use of in-front-of-the meter battery storage**, provided they meet technical conditions that ensure the regulatory critieria.
- **Postponing the entry into force of the additionality criteria until 2035**. This way, RFNBOs could also access the surplus of renewables installations older than three years.

e. The missing piece: hydrogen infrastructure

Flexibility at large scale will ultimately depend on electrolysers' location and the availability of a hydrogen backbone connected to storage sites.

Currently **most hydrogen production is located close to hydrogen demand centres due to the lack of hydrogen intrastructure.** This is why most of hydrogen production is grid connected. As hydrogen infrastucture evolves in the future, electrolysers will be placed closer to VRES sites, decoupling hydrogen production from consumption locations.

---

[78] Real Decreto-ley 7/2026, accessible here.

[79] Energy news, accessible here.

[80] This would allow batteries to discharge electricity under PPAs with electrolyzer developers, maximising use of PV PPAs (more cost-effective than wind PPAs), increasing operating hours, reducing hydrogen costs, and supporting the integration of renewables, which is fully aligned with the Electrification Action Plan's goals of cost-effective, system-friendly electrification.

[81] Because that is exactly where collecting/storing excess energy is needed—it doesn't matter whether it's from additional RES or not.

When the electrolysers are placed next to consumption centres, some operating constraints are imposed by the hydrogen offtaker (as shown in Section "thus limiting their **ability** to fully provide system-friendly flexibility.

Operational constraints to flexibility"). The additional hydrogen transport and storage infrastructure is ideal to fully unlock hydrogen flexibility potential, and transform electrolysers into reliable, multi-timescale flexibility assets, capable of contributing to intraday, weekly and seasonal system balancing.

Focus: Hydrogen Storage

At smaller scale, hydrogen can be stored in tanks. For larger scale, geological formations such as salt caverns are the ideal storage medium. This is the most advanced, although not the only possible solution, which is geographically concentrated in a limited number of regions in Europe (notably around the North Sea basin). Thus, storage infrastructure must be integrated within a wider hydrogen transport network to connect production and demand centres. However, the lead times for storage assets are longer than those of transmission pipelines - an aspect that needs to be taken into account in an integrated infrastructure planning.

Current deployment remains limited, with around 9 TWh of salt cavern storage projects under development compared to an estimated need of around 36 TWh to support a 20 Mt hydrogen system in Europe[82]. Hydrogen storage injection times are not as fast as electrolytic hydrogen production. However, salt caverns can be adapted to provide fast-cycling operations, as it has been proven for instance by Storengy's HyPSTER pilot project[83], no longer restricting hydrogen storage applications to only low-cycling configuration.

The European Commission should:

- **Reduce early investment risk through EU guarantees** with long-term capacity commitments, and mechanisms to manage early revenue gaps that will be crucial to make hydrogen infrastructure bankable[84]. This is to help infrastructure operators avoid volume risk and support them through financing early infrastructural developments while the market ramps up.
- **Prioritise cross-sector infrastructure planning connecting electricity, hydrogen and gas systems** and the recognition of system-beneficial hydrogen infrastructure and flexibility in the upcoming Electrification Action Plan is needed.
- **Implement a CfD mechanism as a tool to de-risk hydrogen storage projects and get them to FID**. This should be developed in a timely manner as lead-up times for storage projects range from 6-12 years.
- **Prioritise permitting procedures, grid connection access and the development of hydrogen** and transport corridors and large-scale hydrogen storage assets to accelerate infrastructure deployment.

---

[82] Hydrogen Europe, "Hydrogen Infrastructure Report 2024", accessible here.
[83] HyPSTER pilot project by Storengy, performing 100 cycles in 90 days, accessible here.
[84] Lowering investment risks for cross-border hydrogen infrastructure, accessible here.

HYDROGEN EUROPE
Avenue Marnix, 23
1000 Brussels
Belgium

secretariat@hydrogeneurope.eu
www.hydrogeneurope.eu