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Flexibility Solutions for High- Renewable Energy Systems

Spain

acciona

BloombergNEF

Foreword

Climate change effects are arising at a much faster pace than the scientific community had anticipated, increasing the need for an urgent, unprecedented and systemic change, in which we cannot allow caution.

The good news is that the world is already electrifying at a record speed, driven by the competitiveness of wind and solar. Today, renewable energies are the lowest-cost and most technologically mature option to lead the transition from a polluting and obsolete energy system to a new and fully decarbonized one.

Therefore, the question is no longer whether clean technologies are going to be the cornerstone of the future energy system, but rather which flexibility options will back them, and how to address the operational and market challenges that will arise. To accelerate renewable market expansion, flexibility solutions have to be harnessed.

In Spain, the focus of this report and ACCIONA's home market, these challenges are especially important. It is a market with huge renewables potential, and also less interconnected than other European countries. In all the flexibility scenarios analyzed, the study has demonstrated the feasibility and cost-effectiveness of a high-renewable system, with renewables achieving over 80% of the electricity mix by 2030, and at least 90% by 2050.

The fact that wind and solar will dominate the future energy mix has special relevance in a country that currently spends €131 million per day on fossil fuel imports. With the ambitious renewable targets recently proposed, and clear paths for phased closure of coal (2020-30) and nuclear power plants (2035), Spain has become a lead country and can take advantage of the great opportunity for economic transformation that this transition represents.

In ACCIONA, the world's largest energy operator dedicated exclusively to renewable energy, with assets in 16 countries in the 5 continents, we have been working for 30 years to demonstrate the viability of a world based on renewables. We hope this report will help the effort towards system decarbonization and the achievement of Spanish targets. All technologies needed to meet the 1.5º goal are already available, and the case for accelerating renewables is compelling, not only in terms of costs, but also in terms of opportunities to guarantee an economic, environmental and socially sustainable future for Spain.

José Manuel Entrecanales

Chairman & CEO, ACCIONA

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90%

Minimum level of zero-carbon generation in Spain in all scenarios

118MtCO2

Cumulative reduction in emissions out to 2050 in flexible EV scenario

6%

Higher power system costs in 2050 without new sources of flexibility.

The transition to an energy system built around renewable generation is gathering pace. However, questions remain as to whether a low-carbon system will have sufficient flexibility to meet future needs. For Spain – a large market with high renewables potential and relatively little interconnection – these questions are particularly pressing. We model a series of scenarios to explore the interplay between gas, energy storage, smart-charging electric vehicles and interconnectors, as Spain's grid adopts increasing volumes of solar and wind.

This report, authored by BloombergNEF in partnership with ACCIONA, combines BNEF's proprietary New Energy Outlook modelling tools with ACCIONA's detailed understanding of the Spanish market to produce five flexibility scenarios. They are all variants of the base case, and are designed to explore the impact of differing degrees of flexible EV charging, energy storage through batteries and interconnection to France. The main conclusions are that:

- **The lowest-cost Spanish power system is driven mainly by wind and solar.** In our base scenario, by 2030, these technologies supply 51% of generation – 33% and 18% of total generation supplied by wind and solar, respectively. By 2050, they generate 75% of electricity. It's worth noting that our base scenario, although ambitious, falls short of Spain's National Energy and Climate Plan 2030 targets both in terms of capacity and generation.
- **New forms of flexibility are key to an affordable, renewables-led power system.** Without energy storage, smart-charging electric vehicles and interconnectors, the Spanish energy transition risks proceeding on a suboptimal path, with a power system reliant on fossil backup and oversized renewables capacity. This will come at a greater cost, with higher emissions.
- There are two types of benefit provided by these flexible technologies:
  - **Integrating larger volumes of renewable generation**. This is done either by shifting excess demand to periods of high renewable generation, or by storing the excess renewable generation for periods of high demand.
  - **Displacing (fossil) backup capacity** that would otherwise be needed for extended periods with little wind or solar generation.
- **Across all scenarios, low-carbon technologies drive Spain's power sector.** The scenario outcomes differ in system cost and emissions, but in all cases, renewable energy achieves over 80% of the electricity mix by 2030, and at least 90% by 2050.
- **The system will be more expensive without 'new' sources of flexibility.** A greater reliance on gas for flexibility leads to higher system costs, more emissions and a greater level of back-up capacity. Under our low-flex scenario, power sector emissions are 6% higher over 2030-40, and 20% higher over 2040-50.
- **EV flexible charging is key to electrify transport at the lowest cost.** The added costs of electrifying road transport, in terms of generating capacity and electricity production, can be halved if vehicles charge more flexibly – from 15% to 7% in 2050, on a per-MWh basis. Emission reductions from gasoline and diesel savings more than compensate for increases in power sector emissions, which, again, are lower with increased charging flexibility.

- **Battery storage developments could lead to a cheaper, cleaner system, but fossil capacity is still needed.** If storage costs fall more rapidly than in the base scenario, the system could see 13% less gas back-up capacity, leading to 12% fewer emissions by 2050. The penetration of zero-carbon generation could reach 95%, but, in the absence of technologies like hydrogen or carbon capture and storage (CCS), significant firm gas capacity is needed to meet peak demand during the weeks of low renewables production.
- **Interconnectors help reduce emissions but their flexibility can be undermined by renewables.** Increasing interconnection to France helps reduce emissions, with little impact on costs. However, as the French and Spanish systems see greater volumes of cheap wind and solar capacity installed, the utilization of the interconnector falls. This is because there are times when France does not need imports from Spain, or vice versa, since wind and solar over-generation increasingly occurs in both countries simultaneously, limiting the flexibility of the interconnection.
- **Relying on wind and solar generation reduces energy imports and price exposure.** Across scenarios, the degree of dependence on gas and electricity imports varies. More storage capacity reduces the need for gas and power imports, limiting exposure to international commodity prices and the risks associated with energy imports. Increased interconnection results in a trade-off between gas and electricity imports, reducing exposure to gas prices while raising exposure to French power prices (although this is not a clear-cut change, since French prices are correlated to gas prices).

Table 1: Summary of scenario outcomes over 2030-40

Scenario	Average system cost	System cost	Emissions	Average fossil capacity as share of peak demand	Average renewable share of generation	Average zero-carbon share of generation
Base case	$44.37/MWh	$145.24bn	203MtCO2	69%	77%	87%
Relative change vs base scenario						
Low-flex	1%	1%	2%	6%	1%	0%
EV	3%	4%	-2%*	2%	-1%	-1%
EV flex	0%	2%	-9%*	-1%	0%	0%
Storage	0%	0%	-1%	-6%	-2%	0%
Interconnector	1%	1%	-6%	-4%	-1%	1%

*Source: BloombergNEF. Note: Color scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Table 2: Summary of scenario outcomes over 2040-50

Scenario	Average system cost	System cost	Emissions	Average fossil capacity as share of peak demand	Average renewable share of generation	Average zero-carbon share of generation
Base case	$48.63/MWh	$165.87bn	163MtCO2	63%	86%	93%
Relative change vs base scenario						
Low-flex	4%	3%	11%	16%	0%	-1%
EV	9%	21%	-41%*	16%	-3%	-3%
EV flex	3%	14%	-64%*	8%	-1%	-1%
Storage	-4%	-4%	-12%	-13%	0%	1%
Interconnector	-1%	-1%	-8%	-4%	-1%	1%

*Source: BloombergNEF. Note: Color scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

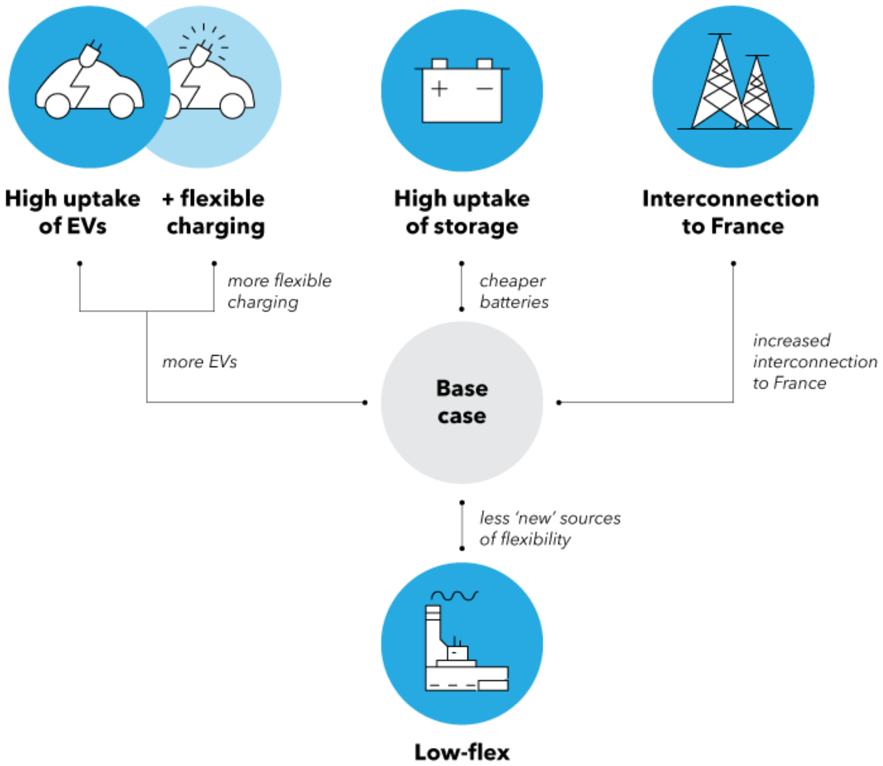
Section 2. Introduction

Spain is at the forefront of the energy transition, having rapidly increased the penetration of renewables in its generation mix to 40% over the past two decades. As the cost of wind and solar energy continues to fall, the question is no longer whether these technologies will be economically competitive. Rather, it is which forms of flexibility are needed to support their uptake.

According to BloombergNEF's 2019 New Energy Outlook – a least-cost modelling exercise based on our understanding of future technology trends – Spain's grid will, by 2050, comprise 88% renewable energy, with the majority of new capacity added between now and 2030. Over the next decade policy makers, regulators and industry players will make important decisions that will shape this transition, for better or worse.

Achieving such a high penetration of renewables will rely on various forms of flexibility that will bridge the gap between supply and demand. Peaker gas plants can play this role, but in doing so will contribute to global carbon dioxide emissions. This report explores the potential role that alternative forms of flexibility – energy storage, flexible electric vehicle charging and interconnections to France – could play, while minimizing both costs and emissions.

Figure 1: Flexibility scenarios



Source: BloombergNEF

We have adopted a scenario-based approach to explore different assumptions about each technology, and how they might impact the overall trajectory of the energy transition. What differs across scenarios are the underlying assumptions about what each technology can provide, and at what cost. In this way, we are able to explore alternative futures for the power system, depending on how each flexibility technology might develop in the coming years.

Where storage, flexible EV charging and interconnectors are successful in our scenarios, it can be inferred that market designs had to be favorable to their introduction and adoption.

Of course, technology is not the only issue. Policy and regulatory approaches to encourage the addition of flexibility are critical, and the scenarios can also be seen in this light. Where storage, flexible EV charging and interconnectors are successful in our scenarios, it can be inferred that market designs had to be favorable for their introduction and adoption.

The scenarios:

- **The base case:** this scenario is consistent with BNEF's house view on technology costs. Batteries become cheaper and electric vehicle charging is partially flexible. The scenario also assumes that some of the interconnection and pumped hydro storage projects that are already in planning will be commissioned.
- **Low-flex:** this scenario looks at the consequences of a future with almost no new sources of flexibility. Here we assume that storage costs remain higher and that electric vehicles are charged with no regard for grid conditions or power prices.
- **High uptake of electric vehicles:** assesses the almost-full electrification of road transport.
- **High uptake of electric vehicles and flexible charging:** assesses the same uptake of electric vehicles as in the previous scenario, but with greater adoption of flexible charging.
- **High uptake of storage:** assesses a future where battery costs fall faster than expected.
- **Interconnection to France:** assesses the impact of increasing interconnection to France.

We begin by outlining the results of modelling our base case, which we then use as a comparison point for the scenarios described above. We conclude by comparing all scenarios and highlighting the relative advantages and disadvantages of the various sources of flexibility under consideration in terms of their ability to support the transition to a low-cost and low-carbon energy system.

Section 3. Base scenario

Our base scenario considers Spain's peninsular electricity system with a focus on technologies that are driving change in markets and business models across the sector, including solar PV, wind and storage. In addition, we put special focus on changing electricity demand, electric vehicles and how they charge, as well as the growing role of consumers.

3.1. Methodology

For the near term, we make market projections based on an assessment of policy drivers and on BloombergNEF's proprietary project database, which provides a detailed insight into planned new build, retrofits and retirements, by country and sector. For the medium to long term, our results emerge from a least-cost optimization exercise, driven by building different power generation technologies to meet projected peak and average demand, taking into account weather extremes.

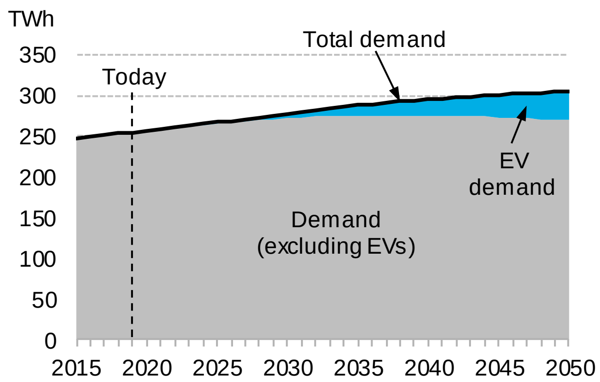
For more details on the modelling methodology, see BloombergNEF's 2019 New Energy Outlook.

3.2. Peninsular Spain[1] forecast

Demand

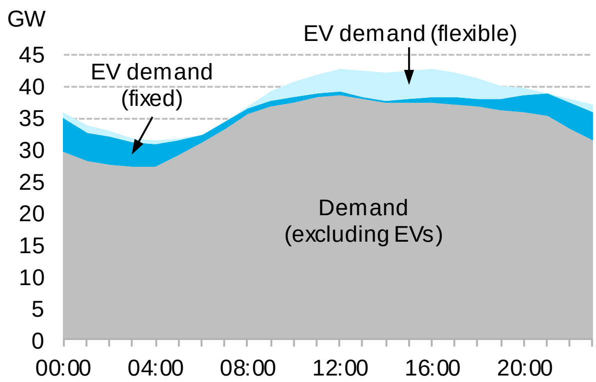
The base scenario assumes that Spanish electricity demand grows 19% between 2019 and 2050, in part driven by the expansion of the electric vehicle fleet, which accounts for 12% of total electricity consumed by 2050 (Figure 2). By 2035, we assume around half of the EVs on the road can charge whenever they are plugged in and can shift their load to hours of low power prices. As a result, Spain's intraday demand profile (Figure 3) changes significantly, shifting to the middle of the day, when cheap solar is available.

Figure 2: Electricity demand breakdown



Source: BloombergNEF

Figure 3: Daily hourly demand profile for a typical summer day in 2050



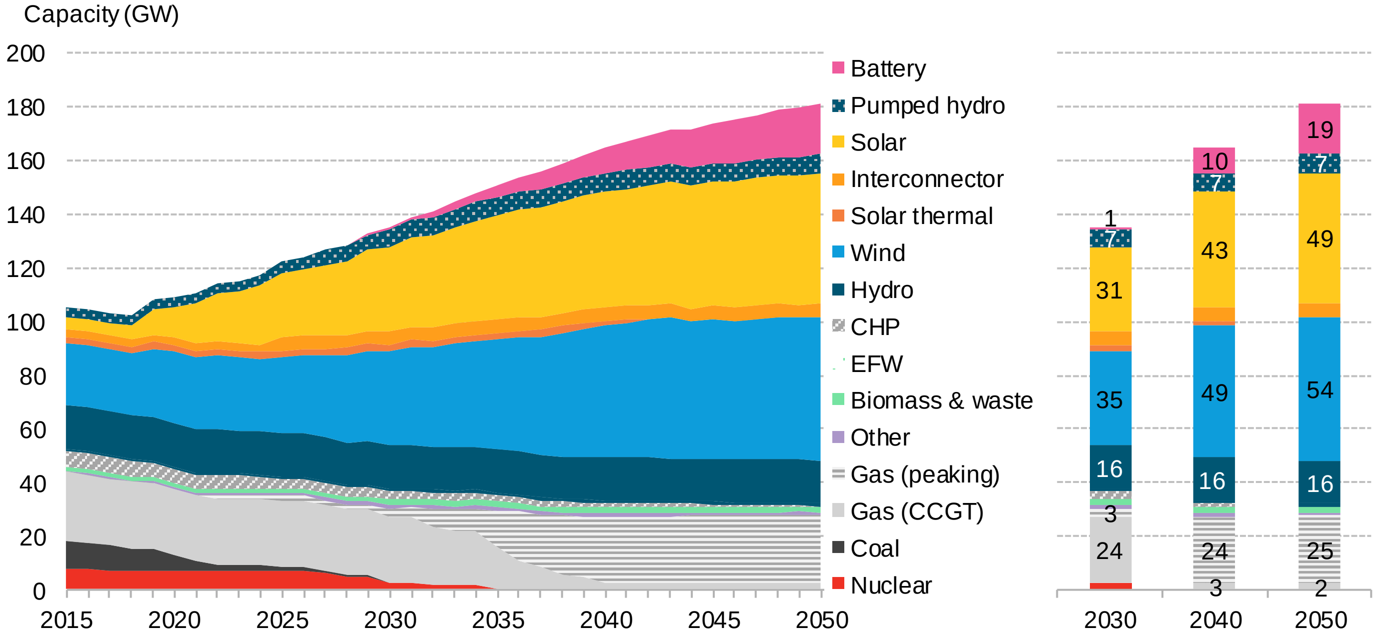
Source: BloombergNEF

[1] Peninsular Spain refers to the Spanish territory located within the Iberian peninsula and excludes other parts of Spain such as the Canary Islands, the Balearic Islands, Ceuta or Melilla.

Generating capacity and generation mix

The generating fleet in peninsular Spain nearly doubles in capacity over 2019-50, from 108GW to 181GW. The growth comes primarily from an increase in wind capacity, which grows from 26GW in 2019 to 54GW by 2050, and solar PV, which grows nearly five-fold, from 10GW in 2019 to 49GW over 2019-50. Half of the growth in wind and solar capacity occurs over the next two decades, with the other half over 2040-50, supported by low-cost utility-scale batteries, which help integrate variable renewables.

Figure 4: Evolution of Spanish generation capacity in base scenario



Source: BloombergNEF

Fossil fuel capacity in peninsular Spain gradually falls over 2017-50, going from 38GW to 29GW, with coal out by 2030 in our base scenario. Conventional gas capacity, ie. combined-cycle gas turbines (CCGT) and combined heat-and-power (CHP), shrinks 92% from 30GW in 2019 to just 2GW in 2050, with most closures occurring over 2030-40. In its place, we see 25GW of peaking gas built over the same period.

Wind generation grows by a factor of three over 2019-50, from 56TWh to 172TWh, supplying more than half of demand. Wind and solar quickly increase their combined share, from 29% in 2019 to 51% in 2030 and 74% in 2050.

The last nuclear plant in Spain closes by 2035, while reservoir and run-of-river hydro capacity remain constant throughout the scenario. Biomass capacity grows modestly, by 800MW out to 2030. We assume interconnection capacity increases in 2025 when the Biscay Gulf interconnector comes online. We also assume 3.5GW of pumped hydro are built, based on Spain's targets and the pipeline of projects.

As a result of these dynamics, Spain's capacity mix goes from being 35% fossil fuel and 35% wind and solar in 2019, to 57% wind and solar and 15% fossil fuel in 2050.

The shift in Spain's capacity mix is clearly reflected in its generation (Figure 6). Wind and solar quickly increase their combined share, from 29% in 2019 to 51% in 2030 and 74% in 2050 (88% including other renewables). Wind generation grows by a factor of three over 2019-50, from 56TWh to 172TWh, supplying more than half of demand. On the other hand, the level of wind and solar curtailment also grows, from 4% in 2019 to 40% by 2050.

How does this scenario compare to Spain's National Energy and Climate Plan?

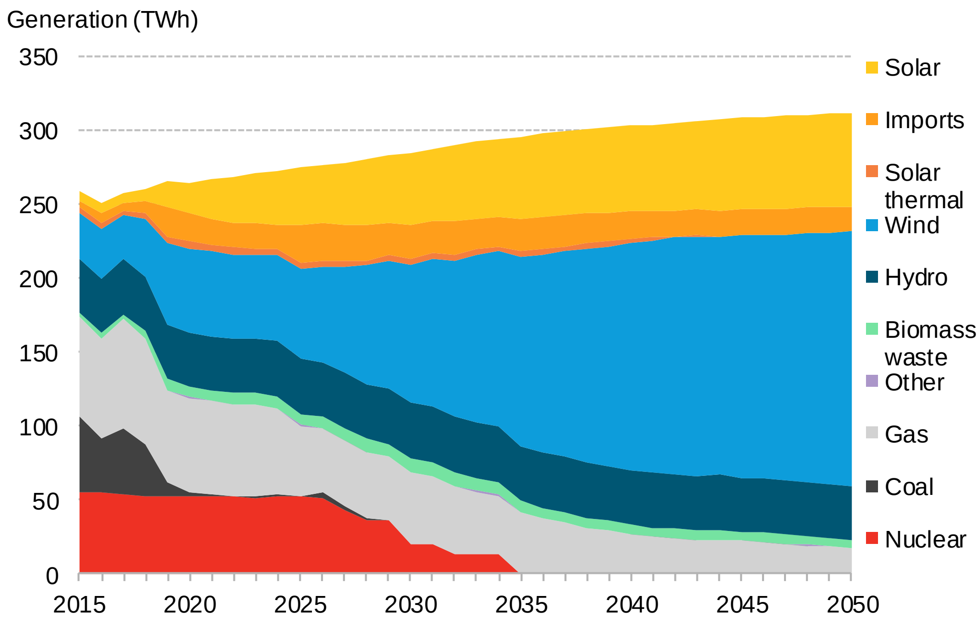
Earlier this year in February, in accordance to EU legislation, Spain submitted a draft of its National Energy and Climate Plan (NECP, or PNIEC in Spanish) for 2021-2030. This plan sets out national targets for Spain in terms of greenhouse gas emissions, as well as the share of renewables in the power mix, and even goes as far as setting specific capacity targets for each technology.

So how do the targets set out by the NECP compare to our least-cost base scenario? The NECP has a 2030 target of 74% renewable electricity generation. Our base scenario falls slightly short of this, at 68%. Equally, the target for CO2 emissions from the power sector in 2030 is 19.7MtCO2, while our base scenario emits 20.8MtCO2 in the same year.

In terms of wind and solar capacity, the NECP aims to achieve 50.2GW and 36.9GW of installed wind and solar PV capacity, respectively. Our base scenario sees less capacity additions from the same sources, at 35.2GW of wind and 31.2GW of solar PV.

Our base scenario achieves 68% renewable electricity generation in 2030, six percentage points below Spain's targets. It also falls short by 20.7GW of wind and solar capacity.

Figure 5: Evolution of peninsular Spain's generation mix in base scenario



Source: BloombergNEF

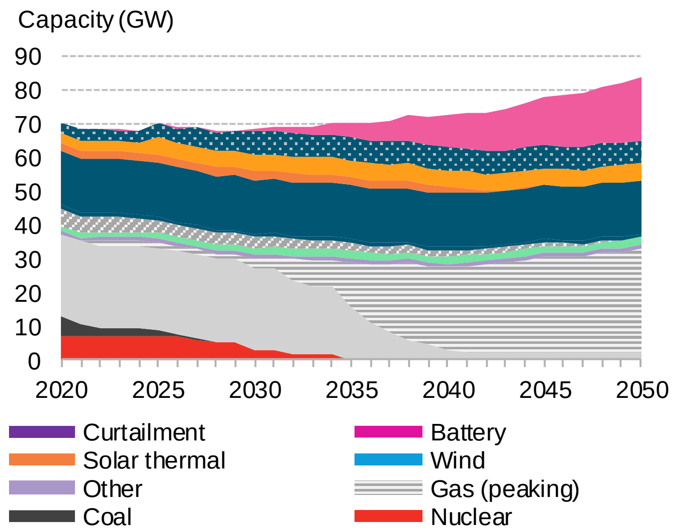
By 2050, Spain installs 19GW of batteries, which make up nearly a quarter of total firm capacity in that year.

Flexibility

As its large baseload nuclear and fossil power plants come offline, Spain shifts to smaller, more nimble installations. In addition to the peaking gas capacity additions, by 2050 Spain installs 19GW of batteries (Figure 6), which make up nearly a quarter of total firm capacity in that year. Our base scenario also assumes 3.5GW of additional pumped hydro coming online over the next decade, as well as 2.2GW of increased interconnection capacity with France by 2025.

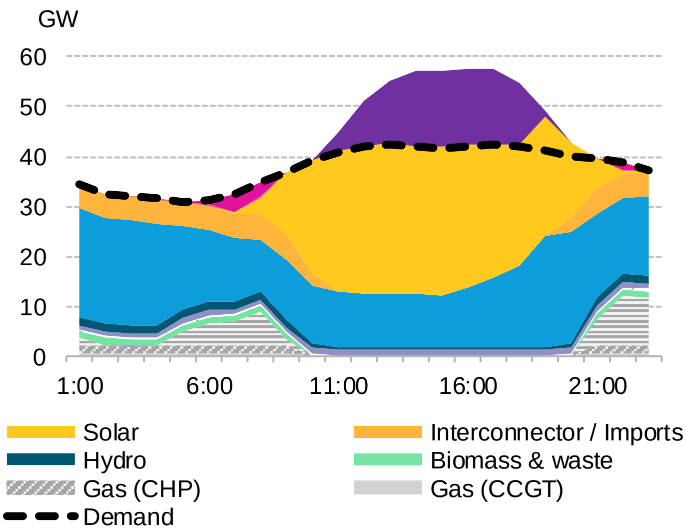
Spain's hydro fleet is also an important provider of firm, flexible capacity – particularly during the first half of the year, when river and reservoir levels are higher. Batteries and pumped hydro storage mainly help absorb excess wind and solar generation and redistribute it to the early morning and later afternoon hours (Figure 7). They also provide quick response to sudden changes in wind and solar output. Gas peakers and interconnectors, for their part, can shoulder the brunt of prolonged lulls in variable renewables output.

Figure 6: Firm capacity



Source: BloombergNEF. Note: Flexible EV demand not shown

Figure 7: Dispatch in median thermal generation day, 2050



Source: BloombergNEF

Figure 8 through Figure 10 show how flexible technologies contribute to meet demand and integrate renewables during weeks with different levels of renewable generation in 2040:

- During a 'low-renewable' output week (Figure 8), there are more than four consecutive days when gas generators are needed to meet demand. During these days, there is little batteries can do to help meet demand, even if after this period batteries do charge and discharge to shift renewable generation from high- to low-output hours. It's worth noting that even during the week with the lowest wind and solar output, there are days with significant curtailment of renewables.
- On a more typical week (Figure 9), we observe higher levels of wind and solar generation, leaving little room for technologies that need to run around the clock. Imports help meet demand when the sun isn't shining, and peaking gas comes on and off sporadically. Batteries are used at some point on a daily basis, charging during the day and discharging when the sun sets.
- In weeks where renewable output is at its highest (Figure 10), all demand is met without the need for fossil generation or energy storage. The level of excess generation from wind and solar is so high that batteries are unable to reduce curtailment, since once charged there is no opportunity for them to discharge.

Figure 8: Week with low renewable output in 2050

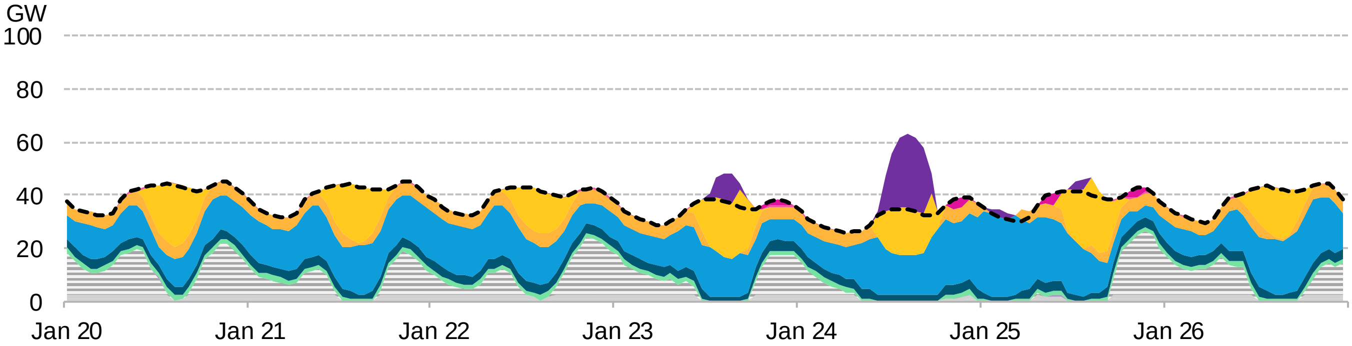


Figure 9: Week with median renewable output in 2050

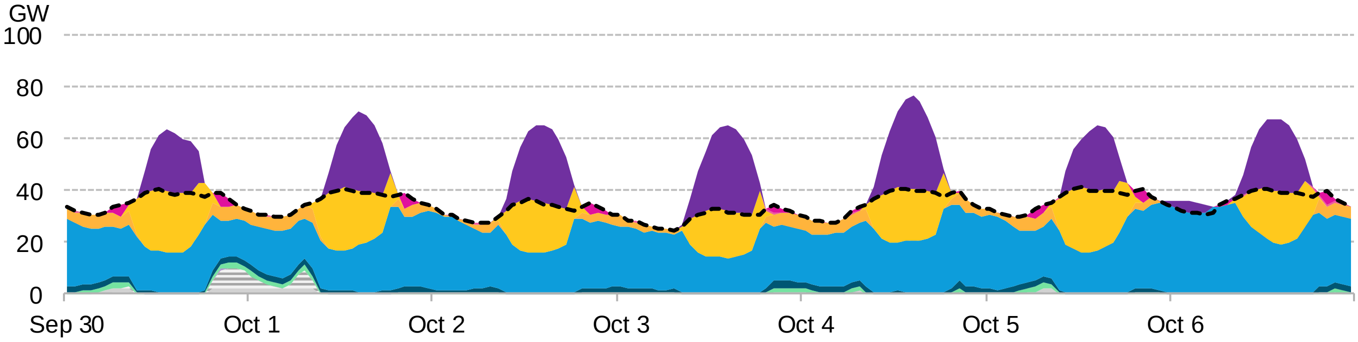
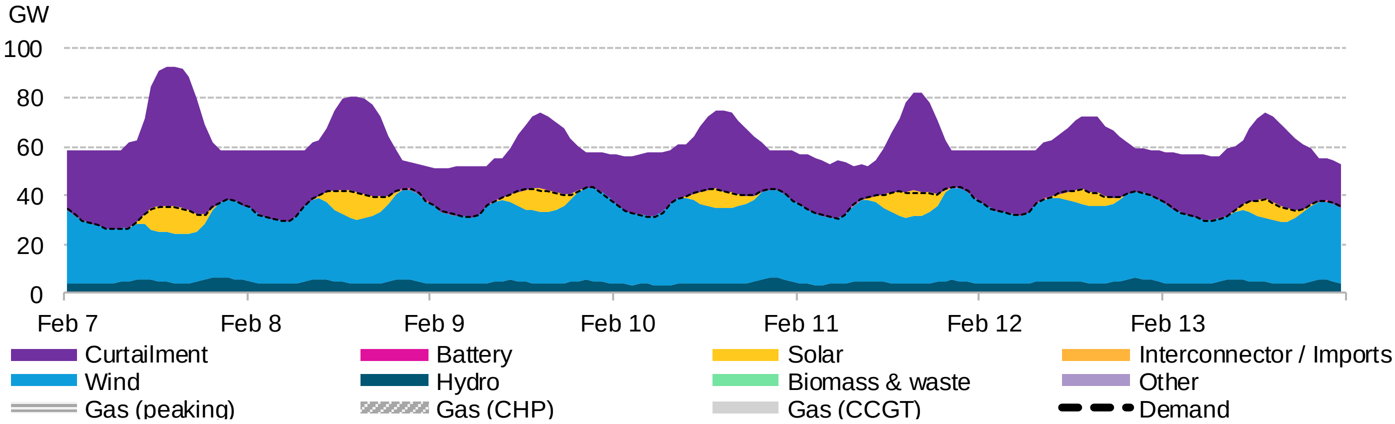


Figure 10: Week with high renewable output in 2050



Source: BloombergNEF

3.3. Implications

By 2030, the Spanish power sector emits 21MtCO_2, or roughly a third of today's emissions.

Spain's power sector emissions fall rapidly as the carbon price bites and coal capacity is retired. By 2030, the Spanish power sector emits 21MtCO_2, or roughly a third of today's emissions. After 2030, however, emissions decline more slowly, reaching 12MtCO_2 in 2050. This slower rate of emissions reduction is partly due to increasing demand from transport electrification, but it also demonstrates the challenge in reaching fully decarbonized systems when relying on peaking gas generation to meet demand over long periods of low wind and solar generation.

Flexible resources play a critical role in the base scenario: by 2050, there is a total of 18GW of battery storage, 6.8GW of pumped hydro, 5GW of de-rated interconnection capacity with France, and 16TWh of flexible EV demand.

With that said, flexible resources such as energy storage and flexible EV charging play a critical role in the base scenario. By 2050, there is a total of 18GW of battery storage, 6.8GW of pumped hydro, 5GW of de-rated interconnection capacity with France, and 16TWh of flexible EV demand that can be shifted to meet renewables production. The next section discusses the low-flex scenario, which highlights how different the outcomes would be if some of these sources of flexibility were unavailable.

The challenge of making money in a system powered by wind and solar

The system this base scenario forecasts to 2050 is based on a least-cost optimization. The model builds the cheapest system that can meet demand at all times, but it does not ensure that each individual asset makes a return on market revenues.

In particular, our analysis shows that in a system with rising penetration of wind and solar, power prices tend to decline (at least, relative to a scenario without growing renewables). This reduces market revenues for all generators and especially for wind and solar projects. Despite declining costs, this dynamic undermines their investment case, and renders much more difficult the task of achieving systems mainly powered by wind and solar, such as the Spanish scenarios in this report. In short, most technologies, including wind and solar, will not be able to rely on energy-only market-based revenues, even when they are very cheap.

As such, for this scenario to materialize, it would require careful market design to provide the right price signals. This would include frameworks for efficient investment in solar PV and both onshore and offshore wind, as well as market-based signals for energy storage and demand shifting.

For the base scenario to materialize, it would require careful market design to provide the right price signals, as well as market-based signals for energy storage and demand shifting.

Table 3: Key metrics for base scenario

Metric	units	2030	2040	2050
System cost	$/MWh	41.6	46.3	51.7
System cost	$bn	12.0	14.1	16.2
Emissions	MtCO2	21	17	12
Fossil capacity as share of peak demand	%	70%	64%	61%
Renewable share of generation	%	68%	84%	88%
Zero-carbon share of generation	%	83%	91%	95%

Source: BloombergNEF

Table 4: Key cumulative metrics for base scenario

Metric	units	2020-30	2030-40	2040-50
Average system cost	$/MWh	35.9	44.4	48.6
System cost	$bn	109.4	145.2	165.9
Emissions	MtCO2	274	203	163
Average fossil capacity as share of peak demand	%	77%	69%	63%
Average renewable share of generation	%	56%	77%	86%
Average zero-carbon share of generation	%	80%	87%	93%

Source: BloombergNEF

3.4. Other scenarios

The next sections explore other scenarios for flexibility, and compare each of them to this base case. It is worth keeping in mind when comparing scenarios that the base case represents a future in which, already, there are significant flexible resources, in particular with a high volume of batteries and a large share of electric vehicles (50%) engaged in smart charging. This is why we present a low-flexibility scenario next for comparison, before showing the high-storage and other scenarios.

Section 4. Low-flex scenario: limited flexibility

In the 'low-flex' scenario, we look at the consequences of a future with almost no new sources of flexibility, where storage costs remain higher and demand inelastic – due to either technical or regulatory issues.

In recent years, variable renewables, namely wind and solar, have enjoyed cost reductions that have exceeded expectations. Like wind and solar, lithium-ion batteries have also seen large cost reductions, but there is more uncertainty surrounding their future costs. If manufacturing does not scale up as quickly as expected, or if there are bottlenecks on critical materials such as lithium or cobalt, this could lead to higher battery pack prices than expected. Trade barriers, or an immature supply chain in Europe, could also lead to higher costs.

Poor market design decisions that introduce misaligned incentives could slow or stop the adoption of storage and flexible EV charging.

This scenario is also designed to reflect the impact of suboptimal policy and regulatory frameworks. Poor market design decisions that introduce misaligned incentives could slow or stop the adoption of storage and flexible EV charging. For example, dynamic pricing or aggregation can encourage residential and business customers to invest in demand-side flexibility, such as small-scale storage or dynamic EV charging. Without these incentives, Spain might not realize the potential of these technologies. Similarly, if power market rules do not appropriately value new sources of flexibility, these technologies may not achieve scale.

EV charging patterns: what does bad look like?

Current EV charging is not very flexible: EVs charge mainly at home when owners return from work, and for the most part chargers do not respond to power price signals. As a consequence, EVs act as a fixed load that peaks in the evening – the same time when power demand is at its highest – increasing the stress on the system.

This can be avoided by distributing charging events throughout the day in response to price signals. However, to do so EVs need access to charging infrastructure for most of the day (not only in the evening). This implies additional investment in workplace and other destination chargers.

This scenario considers the impact on the system in a world where EV drivers are not able to access charging infrastructure outside their homes and thus charge mostly during the evenings, in an uncontrolled manner. What could make matters worse (something we do not explore here) is if rapid charging were to capture a large share of EV charging load. If left uncontrolled (and not supported by onsite storage, for example), this could lead to demand spikes that would drive up costs in the power system.

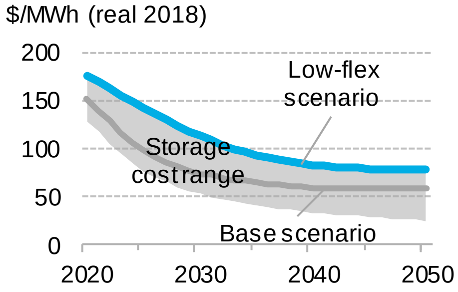
4.1. How this scenario differs from the base case

Input assumptions

To model the low-flexibility scenario, we altered our input assumptions to make battery storage, demand response and EV charging less flexible, available or affordable:

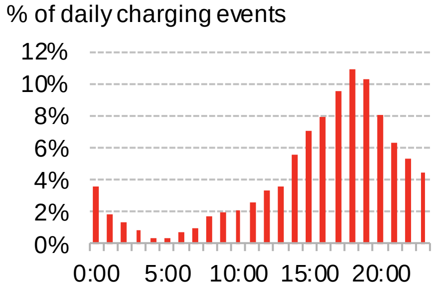
- For battery storage, we assumed a higher cost trajectory that increasingly diverges from the cost assumptions in our base scenario, resulting in a levelized cost of finance (LCOF)[2] that remains above the $100/MWh level until 2032, in real terms (Figure 11).
- We assume that there is no flexible charging for electric vehicles. Instead, they follow a fixed charging pattern that peaks during the evenings – specifically between 6:00 and 7:00 PM based on existing charging data (Figure 12). The vast majority – about 80% – of the fleet charges at home, while the remaining vehicles utilize some sort of public charging infrastructure. This assumption contrasts with our base scenario, which assumes 50% of the fleet charges flexibly by the early 2030s.

Figure 11: Storage levelized cost of finance



Source: BloombergNEF

Figure 12: EV charging profile



Source: BloombergNEF

Together, these assumptions are intended to reflect a future where new flexibility sources are rendered unattractive for project investors, either due to technological reasons or due to sub-optimal power market design and regulatory approaches.

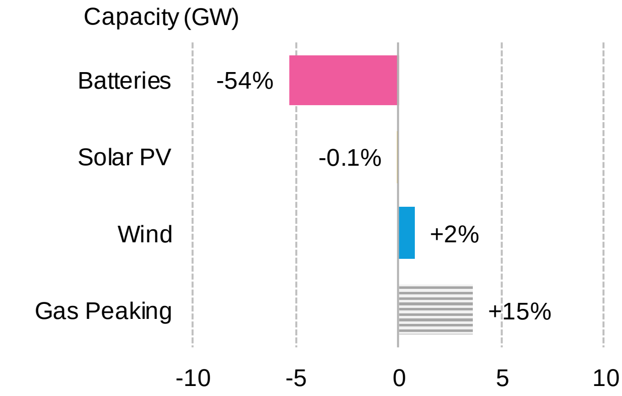
Outcomes

With less battery storage and no flexible EV charging, Spain's power system relies heavily on peaking gas. By 2040, the system in this scenario requires about 3.6GW (15%) more peaker gas capacity than in the base case (Figure 13). By 2050, the system needs an additional 5.7GW of peaker gas capacity, versus the base case, to make up for the lack of battery storage capacity, which is reduced by 47%, or 8.9GW (Figure 14).

In addition to substituting batteries for gas, the most economical option in this scenario requires over 1GW of additional wind capacity to meet demand during certain hours, even if this means curtailing renewable generation more frequently at other times.

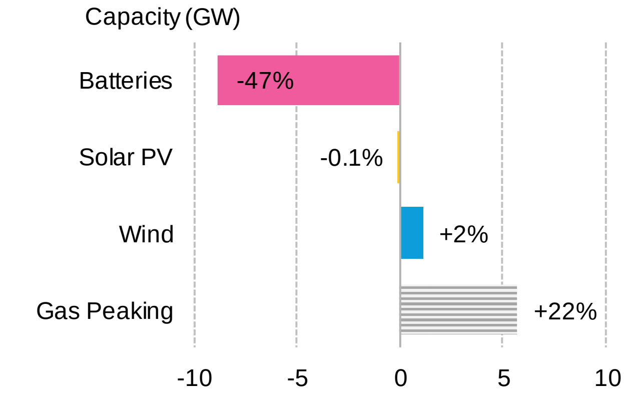
[2] The levelized cost of finance is the long-term off-take price on a MWh-basis needed for a project to pay back its capital costs and hit the equity requirements of investors; it excludes variable costs such as fuel, carbon or charging costs in the case of batteries.

Figure 13: 2040 installed capacity change for low-flex scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 14: 2050 installed capacity change for low-flex scenario, versus base case

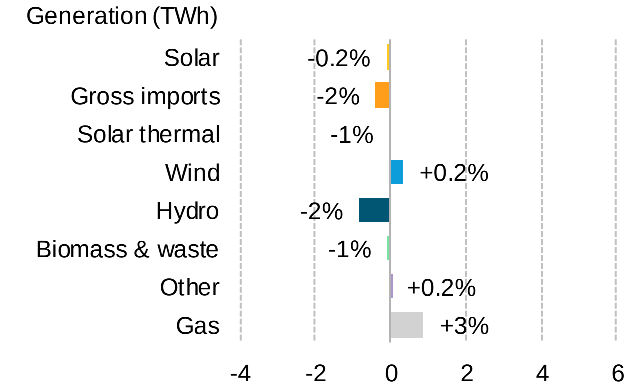


Source: BloombergNEF. Note: percentages show relative change against the base scenario

The lack of new sources of flexibility also impacts the generation mix. This is most noticeable in the long-term over-reliance on gas generation. By 2050, Spain burns 16% more gas in this scenario than in the base case. This dynamic highlights the importance of zero-carbon flexibility options in order to achieve the power sector's deep decarbonization.

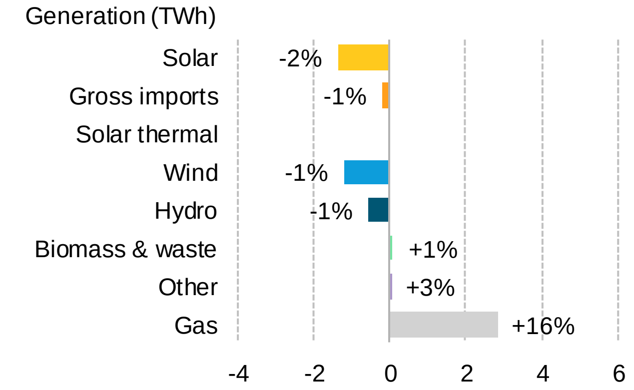
The addition of wind capacity means more wind generation by 2040, when Spain can meet its flexibility needs to a great extent with its existing flexible resources – such as its pumped storage or hydro reservoirs – but still needs to burn 3% more gas. In the longer term, however, there is less wind generation despite the extra capacity – 3% less by 2050. The lack of batteries also means a reduction in solar generation, which is 2% less than in the base case by 2050.

Figure 15: 2040 power generation change for low-flex scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 16: 2050 power generation change for low-flex scenario, versus base case



Source: BloombergNEF. Note: generation figures do not include curtailment

4.2. Implications, benefits and drawbacks of this scenario

In all of our scenarios, the system has enough flexibility to maintain reliable operation – and this one is no different. However, without new sources of flexibility, this is achieved primarily by relying on conventional flexible generators, such as peaker gas capacity, complementing a high penetration of renewable generation. This comes at a higher cost, as it substantially over-sizes renewables and additional investment is needed to build extra peaking capacity. Over 2030-40, the low-flex system is 1% more expensive than in the base case, but over 2040-50 the difference in system costs grows to 3% (Table 6).

Lack of new flexibility does not halt the transition to a renewables-led system, as wind and solar are still cheap to build – even if they go underutilized.

In addition to the added costs, the increased reliance on gas generation means more reliance on gas imports, since Spain has virtually no domestic natural gas resources. This, in turn, increases the exposure of the Spanish power sector to international commodity prices.

Inflexible assets, such as renewables, are underutilized in this scenario, and there is more curtailment. Additional wind capacity is required from the mid-2020s, but by the early 2030s, the output of wind turbines is lower than in the base case, due to curtailment.

Importantly, however, a lack of new flexibility does not halt the transition to a renewables-led system, as wind and solar are still cheap to build (even if they go underutilized). Even in a world where storage and flexible EV charging fall short of their potential, renewables still achieve almost 88% penetration by 2050 (Table 6).

Without low-carbon flexibility sources, it will prove very difficult to achieve deep decarbonization of Spain's power system.

Spain's carbon emissions are higher in this scenario. The reduction of battery storage and flexible EV demand results in a significant increase in yearly emissions, of 2% over 2030-40 and 11% over 2040-50, compared with the base scenario. While the penetration of zero-carbon generation is not significantly affected, being just one percent lower in 2050, it is clear that relying more heavily on gas for flexibility will lead to a higher trajectory for carbon emissions. Without low-carbon flexibility sources, it will prove very difficult to achieve deep decarbonization of Spain's power system.Table 5 and Table 6 summarize the key metrics for the scenario and compares them to the base scenario.

Table 5: Key metrics for low-flex scenario

Metric	Units	2030		2040		2050	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
System cost	$/MWh	42.7	1.1	47.2	0.9	54.9	3.2
System cost	$bn	12.3	0.3	14.4	0.3	17.2	1.0
Emissions	MtCO2	21	0	19	1	14	2
Fossil capacity as share of peak demand	%	72%	2%	72%	8%	74%	13%
Renewable share of generation	%	68%	0%	85%	0%	88%	0%
Zero-carbon share of generation	%	84%	0%	91%	0%	94%	-1%

Source: BloombergNEF

Table 6: Key cumulative metrics for low-flex scenario

Metric	Units	2020-30		2030-40		2040-50	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
Average system cost	$/MWh	35.9	0.0	44.9	0.5	50.4	1.7
System cost	$bn	109.5	0.1	147.0	1.7	171.6	5.7
Emissions	MtCO2	281	7	208	5	182	19
Average fossil capacity as share of peak demand	%	77%	0%	73%	4%	73%	10%
Average renewable share of generation	%	56%	0%	77%	1%	86%	0%
Average zero-carbon share of generation	%	80%	0%	87%	0%	92%	-1%

Source: BloombergNEF

Section 5. Scenario: high uptake of electric vehicles

In an effort to combat air pollution and climate change, countries around the world are supporting the uptake of electric vehicles. The latest draft proposal for Spain's climate change bill[3] includes a ban on the sale of internal combustion engine (ICE) vehicles by 2040. This scenario looks at what almost total electrification of the transport sector might mean for the power system.

5.1. How this scenario differs from the base case

Input assumptions

Using the same tools and methodology as in our Electric Vehicle Outlook,[4] we modelled a full electrification of transport scenario for Spain (Figure 17). This allowed us to estimate the additional electricity demand (Figure 20) needed to power the increase in electric vehicles. EV electricity demand in this scenario starts diverging from the base scenario around 2035, and then nearly trebles by 2050.

We assume the same proportion of flexible charging for electric vehicles as in the base case. That is, at the start of our modelling timeframe, vehicles charge following a fixed pattern that favors charging overnight, while vehicles are parked at home (Figure 19). As the years go by, we assume time-of-use pricing is implemented and vehicles increasingly charge flexibly, responding to conditions in the system. This means that 25% of EV demand is flexible by 2040, and 36% by 2050, resulting in almost three times more terawatt-hours shifting around than in the base scenario (Figure 20).

Figure 17: Fleet composition in EV scenario

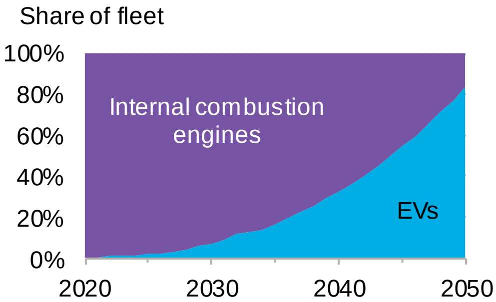
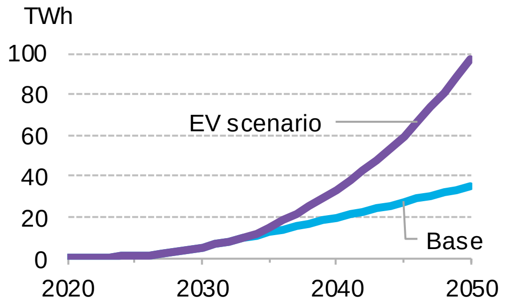


Figure 18: Total EV demand



[3] http://www.congreso.es/public_oficiales/L13/CONG/BOCG/B/BOCG-13-B-48-1.PDF

[4] Bloomberg subscribers can read more in our Electric Vehicle Outlook (web | terminal).

Figure 19: Fixed charging pattern

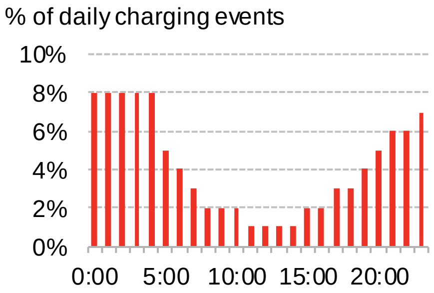
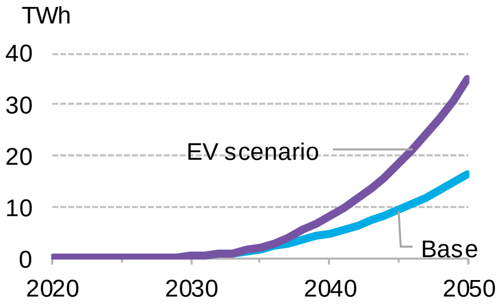


Figure 20: Flexible demand



Source: BloombergNEF

Outcomes

More generation capacity is needed to meet the additional demand from electric vehicles. To do this, the system builds more wind and peaking gas capacity. By 2040, these additions add up to 1.6GW and 1.8GW of extra peaking gas and wind capacity, respectively – increases of 7% and 4% compared to the base scenario (Figure 21). By 2050, additional electricity demand is significantly higher, and consequently the system adds around 15GW of net capacity, or 9% more than in the base scenario (Figure 22).

Figure 21: 2040 generation capacity change for high EV uptake scenario, versus base case

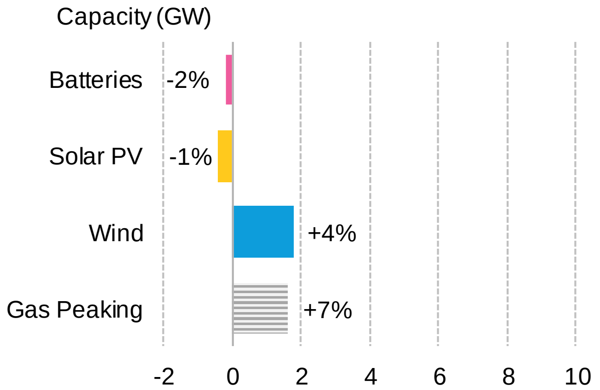
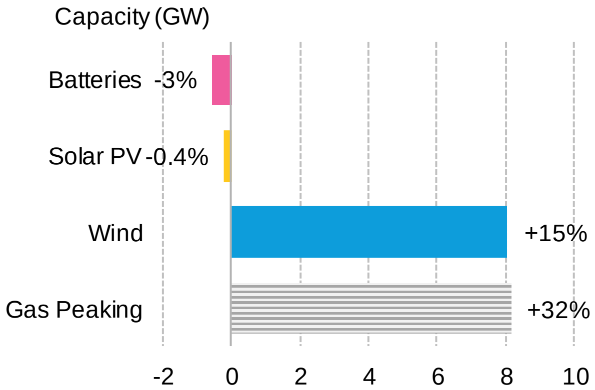


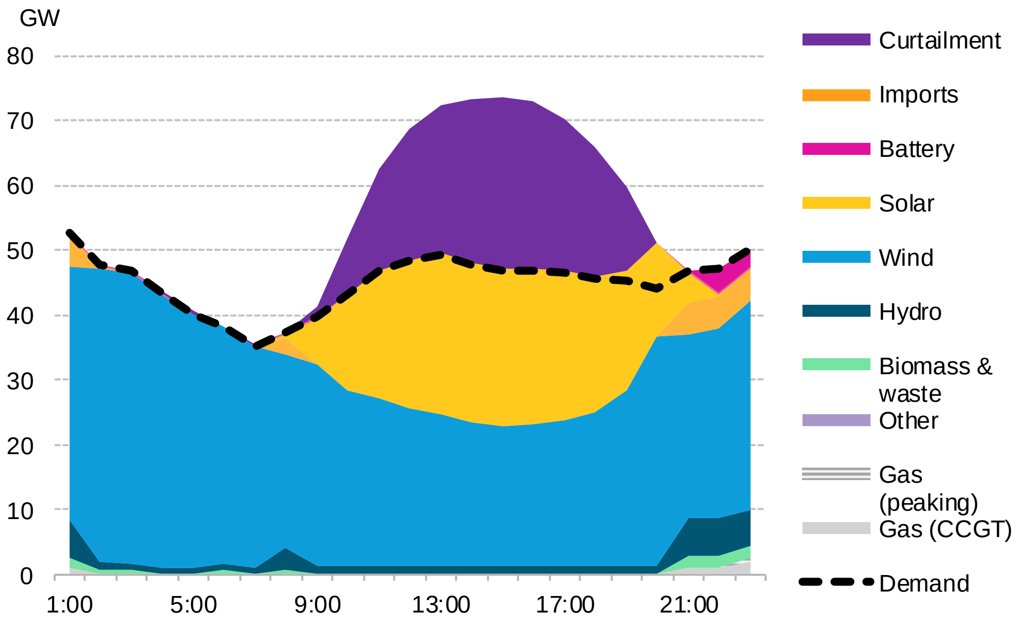
Figure 22: 2050 generation capacity change for high EV uptake scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

A key difference in 2050 (Figure 22), when the EV fleet is reaching sizeable proportions, is that since most of the fixed EV charging happens overnight, solar can contribute little to meet charging demand. Equally, not enough EV demand can be shifted to midday when solar generation gets curtailed – so the system doesn't add any more solar, choosing instead wind for bulk generation. Additional flexibility is provided by gas peakers, which come online to meet demand when generation from wind and other flexible sources is not sufficient. (Figure 23).

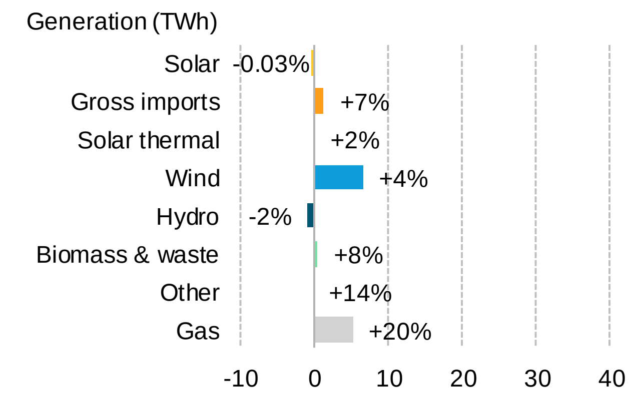
Figure 23: Hourly generation during a typical August day in 2050 for the high EV uptake scenario



Source: BloombergNEF

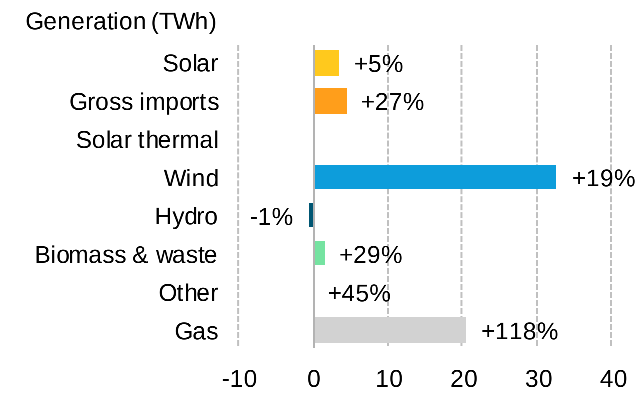
Wind generation grows by 4% and gas generation by 20% by 2040 (Figure 24). By 2050 (Figure 25), there's more generation from wind, solar, gas, biomass and waste, as well as more imports from France. Since wind generation occurs throughout the day and night, it is better suited to meet the base level of inflexible EV charging demand. Gas generation more than doubles and accounts for roughly 10% of total generation – in the base scenario, gas generation makes up 6% in 2050.

Figure 24: 2040 power generation change for high EV uptake scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 25: 2050 power generation change for high EV uptake scenario, versus base case



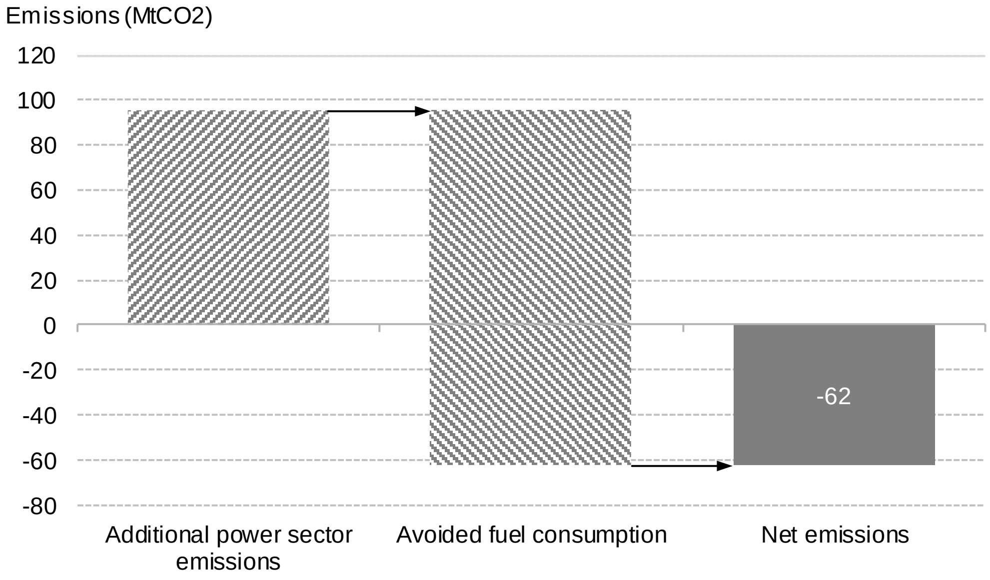
Source: BloombergNEF. Note: percentages show relative change against the base scenario

5.2. Implications, benefits and drawbacks of this scenario

Our analysis shows that the full electrification of transport produces a cumulative net reduction in emissions of 62 MtCO2 over the next three decades, relative to the base scenario.

EVs are the clearest pathway to decarbonizing road transport, with avoided tailpipe emissions more than compensating for additional power sector emissions. Our analysis shows that the full electrification of transport produces a cumulative net reduction in emissions of 62 MtCO2 over the next three decades, relative to the base scenario (Figure 26).

Figure 26: Cumulative net emissions after considering avoided fuel consumption, relative to the base scenario, 2020-50



Source: BloombergNEF

Due to the extra capacity needed to meet more EV demand, the power system becomes 21% more expensive in absolute terms, but only 9% more expensive on a per-MWh basis.

On top of the emissions reduction, the metrics for this scenario show how increasing the amount of electric vehicles has a minimal effect on the penetration of renewables in the generation mix. Over 2040-50, although the power system becomes 21% more expensive in absolute terms due to the extra capacity needed to meet more EV demand, it is only 9% more expensive on per-MWh power system costs[5] (Table 8).

In other words, this analysis shows phasing out the sales of ICE vehicles in favor of EVs could be done without 'breaking' the power system. Table 7 and Table 8 summarize the key metrics for the scenario and compares them to the base scenario.

[5] This estimate does not consider additional infrastructure costs, cost savings from avoided fuel consumption nor potential cost savings from avoided transport sector emissions if they were to become taxed or covered under a carbon market.

Table 7: Key metrics for the high uptake of EVs scenario

Metric	Units	2030		2040		2050	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
System cost	$/MWh	42.9	1.3	48.3	2.0	59.2	7.5
System cost	$bn	12.3	0.3	15.4	1.2	22.3	6.0
Emissions	MtCO2	21	1	4	-13	-39	-51
Fossil capacity as share of peak demand	%	71%	1%	68%	4%	79%	18%
Renewable share of generation	%	68%	0%	83%	-1%	84%	-5%
Zero-carbon share of generation	%	83%	0%	90%	-1%	90%	-4%

Source: BloombergNEF

Table 8: Key cumulative metrics for the high uptake of EVs scenario

Metric	Units	2020-30		2030-40		2040-50	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
Average system cost	$/MWh	35.9	0.0	45.7	1.3	52.9	4.3
System cost	$bn	109.2	-0.1	151.4	6.2	200.6	34.7
Emissions	MtCO2	282	8	200	-4	96	-67
Average fossil capacity as share of peak demand	%	77%	0%	70%	2%	73%	10%
Average renewable share of generation	%	56%	-1%	76%	-1%	84%	-3%
Average zero-carbon share of generation	%	80%	0%	86%	-1%	90%	-3%

Source: BloombergNEF

5.3. Comment on methodology

To estimate net emissions, we calculate the impact of passenger EVs on oil consumption. In our high electrification of transport scenarios for Spain, we estimate that EVs displace an additional 104 thousand barrels per day (kb/d) of fuel in 2040 and 403 kb/d by 2050, versus the base scenario.

Fuel displacement from EV sales is estimated using the following assumptions[6]:

- Each new EV displaces the sale of a new internal combustion engine (ICE) vehicle of equivalent type – small, medium, large or sports utility.
- The resulting level of fuel demand displaced by each EV is a function of the average fuel economy (measured in miles per gallon, or MPG) and utilization (measured in annual miles travelled) of the displaced ICE. Average vehicle utilization in Europe is around 8,000 miles per year, lower than for the U.S. and China.
- We break down fuel displacement across gasoline and diesel by taking into account the split of gasoline versus diesel ICE sales for each vehicle type in each region.
- We assume that a battery electric vehicle (BEV) displaces 80% of the average miles travelled per vehicle in each region. For plug-in hybrid vehicles (PHEVs), we do not discount vehicle utilization, but assume that a PHEV consumes 50% of the fuel of an equivalent ICE.

[6] Bloomberg subscribers can read more on how we estimate oil displacement in *How Much Oil Are Electric Vehicles Displacing?* (web | terminal)

Section 6. Scenario: high uptake of electric vehicles and flexible charging

While the previous scenario highlighted the impact that a high uptake of electric vehicles could have on the power system, it assumed that the potential flexibility of these cars was unused. In this scenario, we consider the same high uptake of electric vehicles as in the previous scenario but with a greater degree of flexible charging.

How to get to high levels of smart charging

While in this scenario we explore the benefits that smart charging could have at a system level, this will not happen of its own accord. There are various measures that would need to be taken to enable and encourage drivers to charge their vehicles in a way that supports the grid overall. These include:

- **Ubiquitous smart charging points:** for up to 80% of EVs to be able to charge at any point in time essentially means that they have to be connected to a charge point whenever they are stationary. That means charge points in multiple locations.
- **Appropriately designed incentives and policy measures:** behavioral economics suggests that consumers are more strongly motivated by avoiding losses than the prospect of gains. Policy makers and grid providers face a delicate challenge of creating incentives that motivate changing behavior without creating a backlash.
- **Effective communication strategy:** consumers are also more likely to accept a new proposition, such as smart charging, if they feel that their decision is in line with the behavior of their peers. Additionally, drivers must be comfortable with an algorithm controlling and optimizing the car's charging in response to power market conditions. Both of these points require a targeted communication strategy.

6.1. How this scenario differs from the base scenario

Input assumptions

This scenario assumes the same uptake of electric vehicles (and the associated increase in electricity demand) as the previous scenario. The key difference is that the share of EVs charging flexibly is higher, which means that by 2030 flexible demand is 3.2TWh, or 2.8TWh higher than in the EV scenario; by 2050 this number grows to 49.8TWh or 14.8TWh more than in the EV scenario (Figure 30).

Figure 27: Vehicle fleet

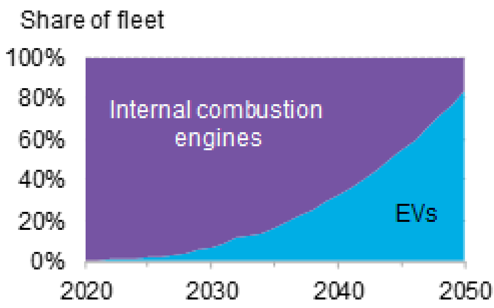


Figure 28: EV demand

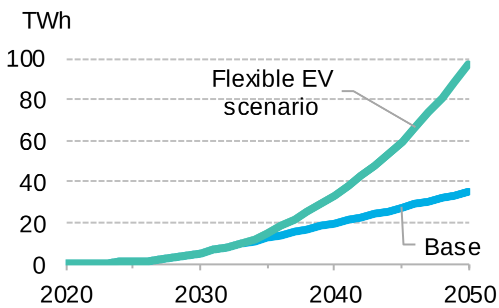


Figure 29: Daily fixed charging demand in 2035

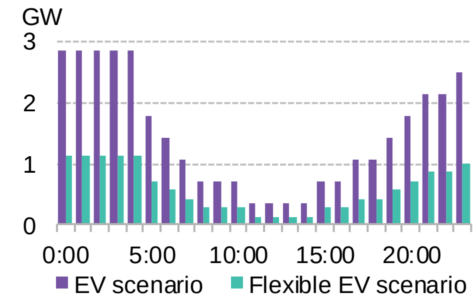
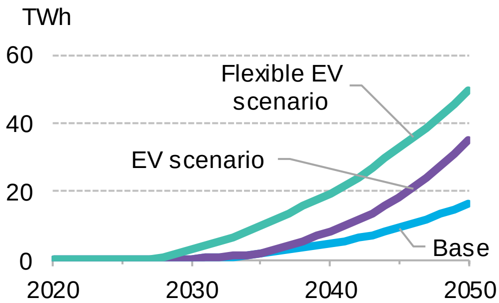


Figure 30: Flexible demand



Source: BloombergNEF

Outcomes

Although most of the inputs are similar to those in the previous scenario, the ability to charge flexibly has a strong influence on the energy system. For starters, charging flexibly is equivalent to load shifting, which reduces the need for other forms of system flexibility. Consequently, in 2040, the need for peaking gas capacity grows by only 1% relative to the base scenario and is 6% lower than in the previous (high-EV) scenario. We also see a preference for solar over wind capacity, compared to the previous scenario, as charging demand can shift to the middle of the day to benefit from cheap solar generation. Flexible EV charging is effectively supporting renewable energy (Figure 31).

By 2050, we see more peaking gas capacity than in the base scenario, as there is now a noticeable increase in power demand. However, this 20% gain in gas is still less than the capacity needed in the previous scenario (a 32% gain), when EV charging is less flexible. The biggest difference in 2050 is the nearly 4.5GW of solar capacity additions compared to the base scenario. This contrast with the slight reduction of 0.2GW in the previous scenario (Figure 32).

Figure 31: 2040 generation capacity change for high flexible EV uptake scenario, versus base case

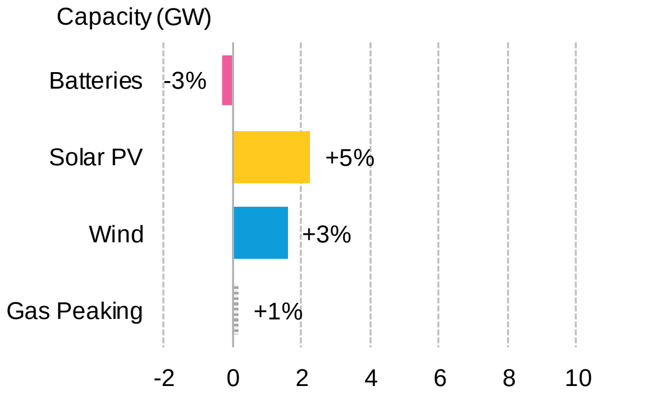
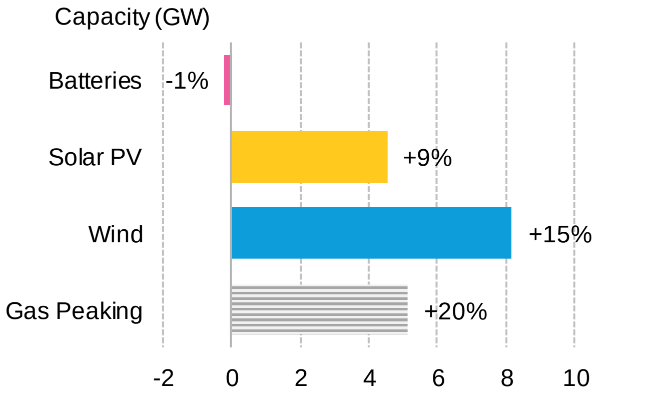


Figure 32: 2050 generation capacity change for high flexible EV uptake scenario, versus base case



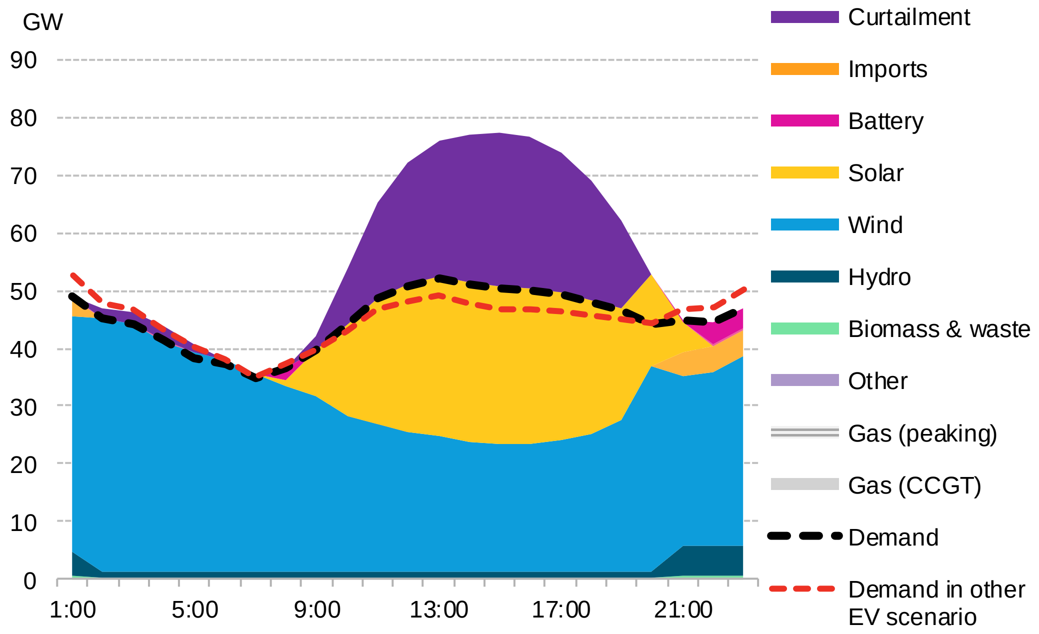
Source: BloombergNEF. Note: percentages show relative change against the base scenario

Flexible charging has a major impact on hourly load profiles, concentrating demand during periods of abundant generation. This tends to favor solar over wind in this scenario. For example, Figure 33 shows a typical day in August 2050, where the clustering of demand during the middle of a sunny day is clearly visible. During the night, demand falls and batteries shift excess mid-day generation to fill the gap, with the result that there in little need for fossil generation.

Due to the low costs of solar capacity, it will be more economical to waste solar generation on some days than to rely on other, more flexible sources of generation

Note that even with batteries and flexible demand there is some curtailed energy. This reflects a new economic reality: due to the low costs of solar capacity, it will be more economical to waste solar generation on some days than to rely on other, more flexible sources of generation.

Figure 33: Hourly generation during a typical August day in 2050 for the high flexible EV uptake scenario



Source: BloombergNEF

In terms of generation, we see that the additional charging flexibility helps to integrate variable renewables and reduce the need for gas-fired electricity. This is most obvious in 2050, when gas generation is lower than in the previous scenario – an 81% increase in the high flexible-charging scenario versus a 118% increase the previous high-electrification scenario (Figure 35). Another way to view it is that in this scenario gas generation makes up 8% of the generation mix in 2050, versus 6% in the base scenario. In other words, the system is supplying much more electricity overall, without significantly increasing the carbon intensity of the generation mix.

Figure 34: 2040 power generation change for high flexible EV uptake scenario, versus base case

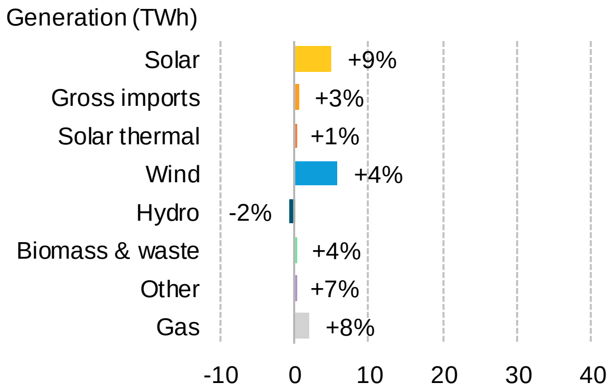
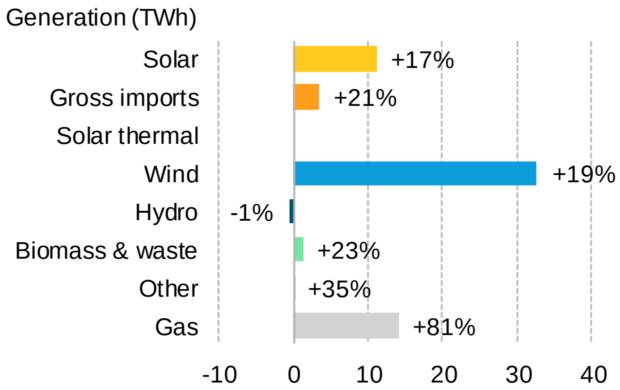


Figure 35: 2050 power generation change for high flexible EV uptake scenario, versus base case



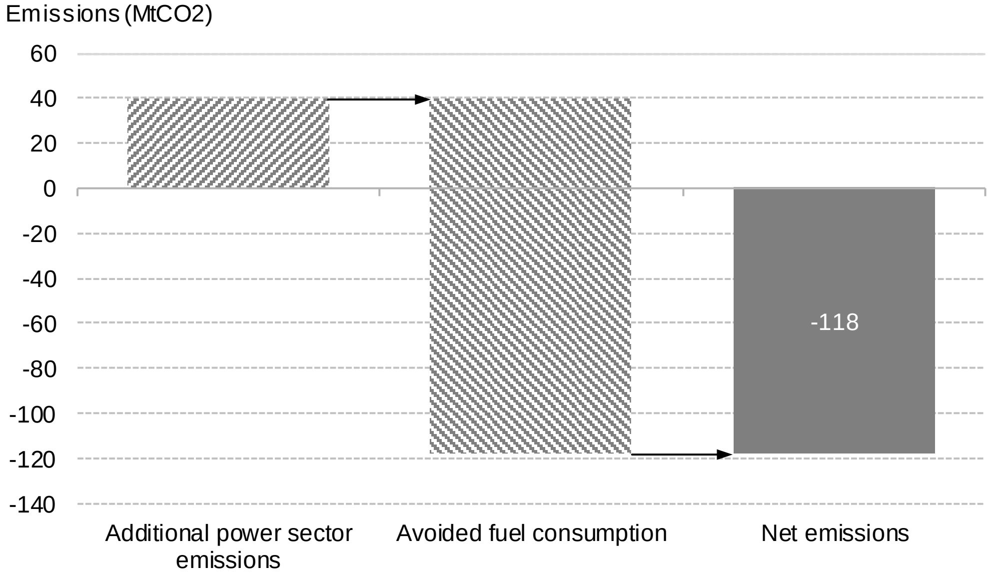
Source: BloombergNEF. Note: percentages show relative change against the base scenario

6.2. Implications, benefits and drawbacks of this scenario

The full electrification of transport in this high flexible-charging scenario produces a cumulative net reduction in emissions of 118MtCO2.

EVs are the clearest path to decarbonize road transport, and flexible EVs even more so, with flexible charging resulting in an additional reduction in carbon emissions of 56MtCO2 compared to the previous high-electrification scenario. Our analysis shows that the full electrification of transport in this high flexible-charging scenario produces a cumulative net reduction in emissions of 118MtCO2 over the next three decades, relative to the base scenario.

Figure 36: Net emissions after considering avoided fuel consumption, relative to the base scenario, 2020-50



Source: BloombergNEF

In terms of unitary electricity costs, this scenario is in fact only 3% more expensive than the base, and is 6% cheaper than the high-electrification scenario.

More flexible charging also results in a cheaper system than the previous scenario – albeit still more expensive than the base scenario, which has much lower EV demand. Over 2040-50, this scenario is 14% more expensive than the base scenario, but this addition is lower than the 21% of the high-electrification scenario (without flexible charging). In terms of electricity costs per megawatt-hour, this scenario is in fact only 3% more expensive than the base, and is 6% cheaper than the high-electrification scenario. In summary, the system becomes cleaner and cheaper the more flexibly EVs charge (Table 10).

However, this imposes costs and challenges at other levels, such as behavioral change and digital infrastructure to enable flexible charging to happen, or charging infrastructure and network costs to cope with high coincident grid load whenever renewable supply is abundant.

Table 9 and Table 10 summarize the key metrics for the scenario and compares them to the base scenario.

Table 9: Key metrics for the high uptake of flexible EVs scenario

Metric	Units	2030		2040		2050	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
System cost	$/MWh	42.3	0.7	46.3	0.0	55.4	3.7
System cost	$bn	12.1	0.1	14.7	0.6	20.8	4.6
Emissions	MtCO2	21	0	1	-16	-44	-56
Fossil capacity as share of peak demand	%	70%	-1%	64%	0%	72%	11%
Renewable share of generation	%	68%	0%	84%	0%	86%	-3%
Zero-carbon share of generation	%	83%	0%	91%	0%	92%	-3%

Source: BloombergNEF

Table 10: Key cumulative metrics for the high uptake of flexible EVs scenario

Metric	Units	2020-30		2030-40		2040-50	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
Average system cost	$/MWh	35.7	-0.1	44.5	0.1	49.9	1.2
System cost	$bn	108.8	-0.6	147.5	2.3	189.1	23.2
Emissions	MtCO2	278	5	185	-19	59	-104
Average fossil capacity as share of peak demand	%	76%	-1%	68%	0%	68%	5%
Average renewable share of generation	%	56%	0%	77%	0%	85%	-1%
Average zero-carbon share of generation	%	80%	0%	87%	0%	92%	-1%

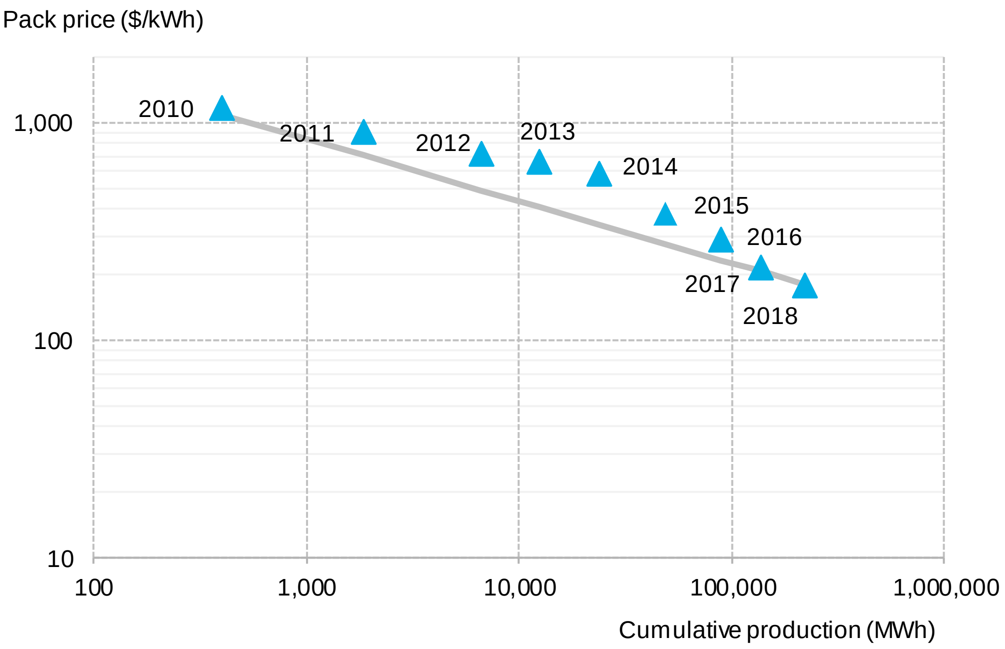
Source: BloombergNEF

Section 7. Scenario: high uptake of storage

Thanks to technological innovation and scale expansion, lithium-ion pack prices have fallen by 85% over 2010-18 on the back of increasing annual battery demand from the automotive and portable electronics sectors. However, battery costs could come down faster than we project, just like wind and solar costs did, and this scenario investigates the impact of this possibility on the Spanish power system.

Lithium cell manufacturing capacity is expected to more than triple by 2023. The fight to secure market share in such a growing market could see prices drop faster than our expectations, which are based on recent trends. A breakthrough in technology could also result in a step-change in cost reductions. Our forecasts are based on existing lithium-ion technologies, but breakthroughs in different chemistries, high voltage-cells or solid-state batteries could result in lower costs.

Figure 37: Prices and learning rates for lithium-ion battery packs



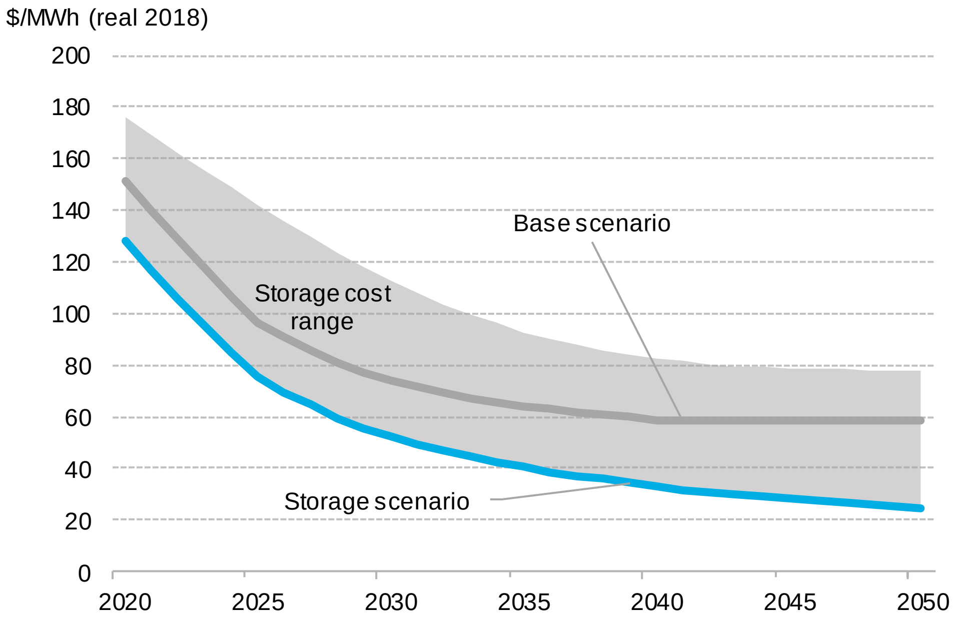
Source: BloombergNEF

7.1. How this scenario differs from the base scenario

Input assumptions

To reflect a low-cost battery scenario, we used the parameters on the lowest end of our cost range. This gives us a reduction in the levelized costs of finance for battery storage of roughly $25/MWh, on average, over the forecast period, compared to the base scenario – although the gap remains fairly constant in absolute terms, the relative difference is considerably greater in the long-term, at around 50-60% lower costs.

Figure 38: Battery storage levelized cost of finance[7]



Source: BloombergNEF

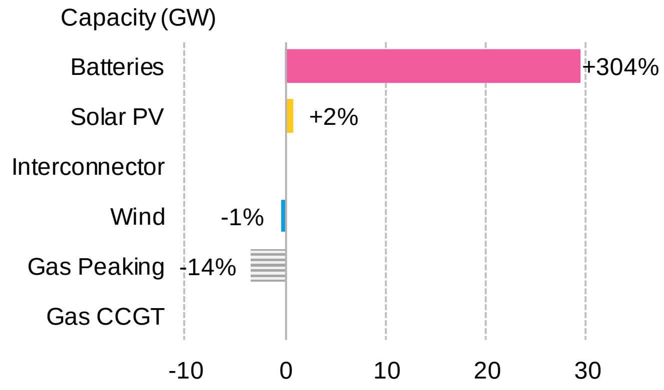
Outcomes

Cheaper storage results in more battery build, and, in the long term, less peaking gas. Relative to our base case, 30GW – or four times – more utility-scale battery capacity is built by 2040 (Figure 39), which replaces 3.4GW of peaking gas capacity.

By 2050, there are nearly 21GW more battery storage than in the base scenario, virtually twice as much capacity (Figure 40). The main effect of this extra battery installation is to displace 15% of the peaking gas capacity in the long term. It also allows the modest addition of 2.5GW of wind and solar capacity.

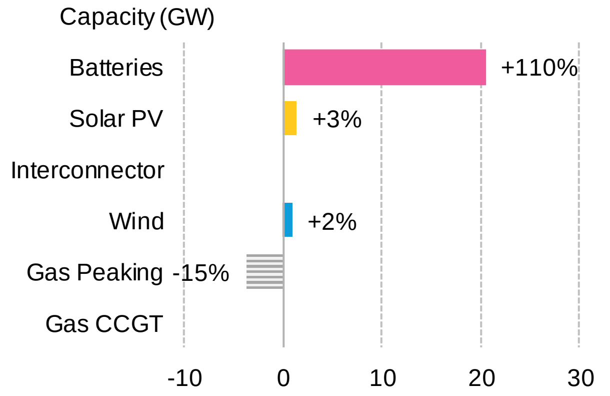
[7] The levelized cost of finance is the long-term off-take price on a MWh-basis needed for a project to pay back its capital costs and hit the equity requirements of investors; it excludes variable costs such as fuel, carbon or charging costs in the case of batteries.

Figure 39: 2040 generation capacity change for high storage uptake scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 40: 2050 generation capacity change for high storage uptake scenario, versus base case



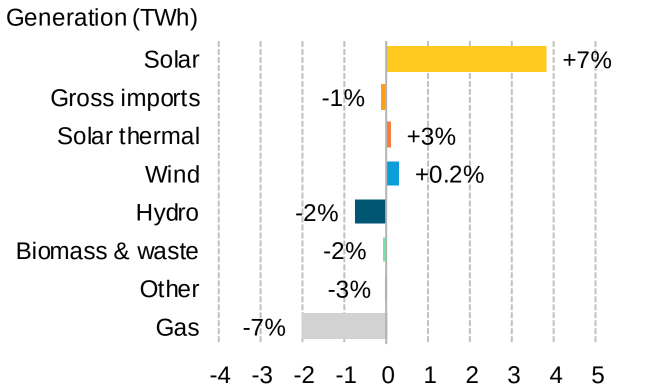
Source: BloombergNEF. Note: percentages show relative change against the base scenario

The additional storage capacity only replaces fossil backup capacity at a rate of 9 to 1 in 2040, or 5 to 1 in 2050.

Interestingly, in the long term, when renewables penetration is greater than 80%, the additional storage capacity only replaces fossil backup capacity at a rate of 9 to 1 in 2040, or 5 to 1 in 2050 (ie 5GW of storage replaces 1GW of peaking capacity). This is because storage has a relatively short duration, unable to meet peak demand in periods when there is little renewables output over several consecutive days.

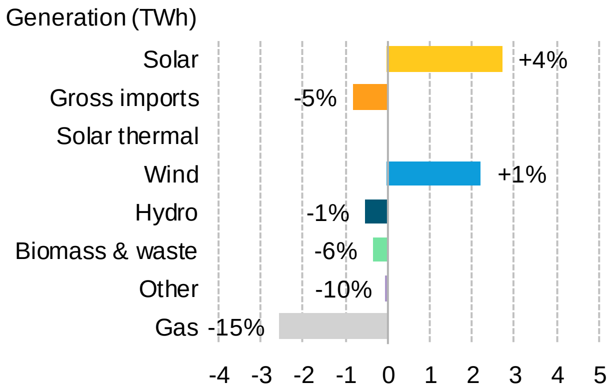
The growth in storage capacity reduces gas generation by 7% in 2040 (Figure 41) and 15% in 2050, in line with peaker gas capacity in this latter year (Figure 42). This means fewer peaker plants are required to fill the short gaps in renewables output that batteries can close, but those gas plants that remain see higher utilization. With greater ability to shift wind and solar generation, less imported electricity is required and more wind and solar generation can be integrated.

Figure 41: 2040 power generation change for high storage uptake scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

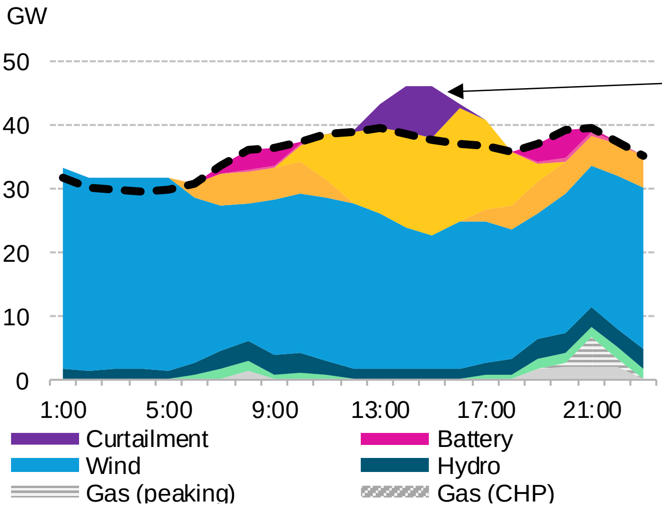
Figure 42: 2050 power generation change for high storage uptake scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

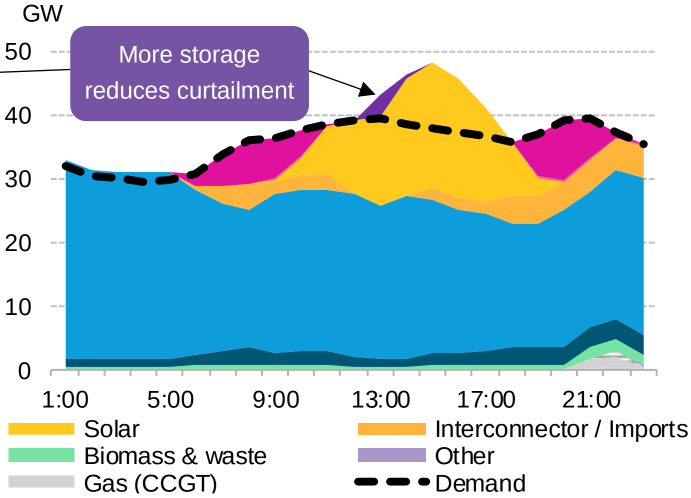
In 2040, solar generation grows by 7% (Figure 41), while in 2050 solar and wind generation are 4% and 1% higher, respectively, than in the base scenario (Figure 42), as the growth in energy storage allows the system to shift would-be curtailed generation to hours when it is needed (Figure 43 and Figure 44). As a result, the system is significantly less reliant on gas and electricity imports. Gas generation is 15% lower than in the base scenario, while 5% less electricity imports are needed.

Figure 43: Hourly generation during an October day with high storage use in the base scenario – 2050



Source: BloombergNEF

Figure 44: generation during an October day with high storage use in the high storage uptake scenario – 2050



Source: BloombergNEF

7.2. Implications, benefits and drawbacks of this scenario

Over 2040-50, emissions are 12% lower, equivalent to a reduction of 18.9MtCO2.

The availability of low-cost batteries can help accelerate the energy transition by adding value to renewables. In the short to medium term, the flexibility of batteries not only contributes to better integrated renewables, but it also increases the utilization of CCGTs over more flexible but less efficient gas. In the long term, cheap battery storage reduces the need for peaking gas capacity. Over 2030-40, this results in the same costs, but over 2040-50 results in a 4% lower system cost (Table 12).

Cheap storage also accelerates decarbonization. This is most notable in the long term, when there is a larger difference in battery costs across scenarios. Over 2030-40, total emissions are 1% lower than in the base scenario, equivalent to a reduction of 2.8MtCO2 in that period. Over 2040-50, emissions are 12% lower, equivalent to a reduction of 18.9MtCO2.

Another aspect of this scenario is that by substituting gas with solar and wind generation, Spain can meet more of its demand with its own resources, reducing the need to procure fuel and electricity abroad. Naturally this would reduce the sector's exposure to commodity prices.

A system running on batteries is not capable of completely displacing fossil peaking capacity.

Batteries are a good way to shift energy across hours or days, where they can contribute significantly to meeting peak demand. However, there is little batteries can do to help meet demand during extended periods of low renewable output. Thus, a system running on batteries is not capable of completely displacing fossil peaking capacity. This would require zero-carbon seasonal storage or dispatchable generation.

Table 11 and Table 12 summarize the key metrics for the scenario and compares them to the base scenario.

Table 11: Key metrics for the high uptake of storage scenario

Metric	Units	2030		2040		2050	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
System cost	$/MWh	41.5	0.0	45.1	-1.2	50.1	-1.6
System cost	$bn	12.0	0.0	13.8	-0.3	15.8	-0.5
Emissions	MtCO2	21	0	16	-1	10	-2
Fossil capacity as share of peak demand	%	70%	-1%	56%	-8%	53%	-8%
Renewable share of generation	%	67%	-1%	83%	-1%	88%	0%
Zero-carbon share of generation	%	83%	0%	92%	1%	95%	1%

Source: BloombergNEF

Table 12: Key cumulative metrics for the high uptake of storage scenario

Metric	Units	2020-30		2030-40		2040-50	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
Average system cost	$/MWh	35.6	-0.3	44.2	-0.1	46.6	-2.0
System cost	$bn	108.7	-0.6	145.0	-0.2	159.5	-6.3
Emissions	MtCO2	273	-1	200	-3	144	-19
Average fossil capacity as share of peak demand	%	75%	-1%	64%	-4%	55%	-8%
Average renewable share of generation	%	55%	-1%	76%	-1%	86%	0%
Average zero-carbon share of generation	%	80%	0%	87%	0%	94%	1%

Source: BloombergNEF

Section 8. Scenario: greater interconnection to France

The European Commission set an interconnection target of at least 10% of installed generation capacity by 2020 and proposed to extend this to 15% by 2030, considering the cost aspects and the potential of commercial exchanges in the relevant regions.[8] This scenario considers the impact of additional interconnection capacity with France on the Spanish power system.

While Spain will miss the 2020 target, there are various projects at different stages of development that are aimed at increasing interconnection with France. The point of interconnecting neighboring systems is to share resources over larger geographical regions. This increases the diversity of generation resources and smoothes the aggregated output of variable renewable resources, thanks to their dispersal over a wider area. In principle, more interconnection results in a less volatile and more flexible system overall.

However, building interconnection capacity has its own challenges, such as local opposition, coordination between various administrations, and frequent and severe cost overruns usually associated with large infrastructure projects. In particular, the border between Spain and France runs along the Pyrenees, so building transmission lines across the mountain range comes with a higher degree of technical difficulty and cost.

8.1. How this scenario differs from the base scenario

Input assumptions

We modelled increased interconnector capacity between Spain and France based on one of the two projects under consideration across the Pyrenees: the Navarra-Landes project with a net transfer capacity of 1.5GW[9] (Figure 45 and Figure 46). This project is currently in the planning stages, but hasn't secured permits. However it is representative of the type of project being considered to expand interconnection capacity in the region.

We assume that the project begins operations in 2030, three years later than the project's planned commissioning date, to account for delays, which are common in large infrastructure projects. This means that the interconnector capacity remains constant from then on and any changes in flows between the regions are solely due to market conditions.

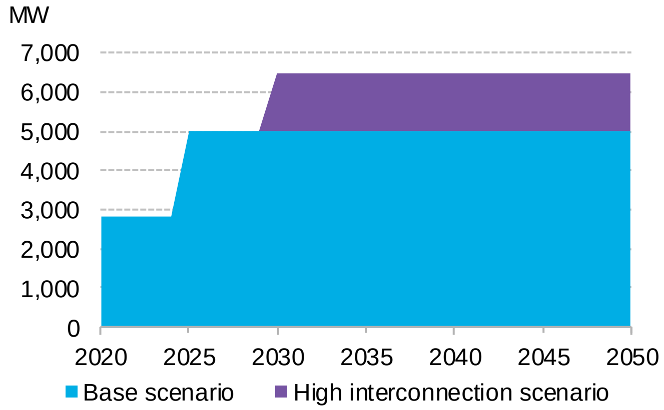
[8] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest/electricity-interconnection-targets/expert-group-electricity-interconnection-targets

[9] https://tyndp.entsoe.eu/tyndp2018/projects/projects/276

Our approach to modelling interconnection

- To incorporate interconnection between France and Spain, we modelled the hourly dispatch of both regions simultaneously, limiting the exchange of energy between them by the interconnection capacity. Power exchanges occurred when a region would have otherwise needed to generate using a more expensive source than the marginal source in the other region.
- We assumed a de-rating factor of 40% for interconnectors – i.e. the interconnectors contribute at least 40% of their nameplate capacity to help meet peak load.

Figure 45: Timeline of interconnection capacity



Source: ENTSOe, BloombergNEF

Figure 46: Interconnector project map

Source: ENTSOe

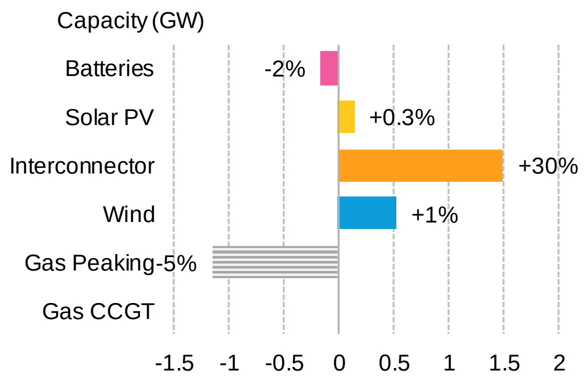
Outcomes

Interconnectors reduce the need for fossil capacity almost like-for-like. The added interconnector capacity results in a reduction of 2.6GW for wind by 2050.

Increasing the interconnection capacity between France and Spain has a clear impact on the need for peaking gas capacity. It reduces gas peaker requirements by 1.2GW compared to the figure in the base scenario consistently across the projection. This means a reduction of 5% in 2040 (Figure 47) that remains at the same level out to 2050 (Figure 48). These figures show that interconnectors reduce the need for fossil capacity almost like-for-like.

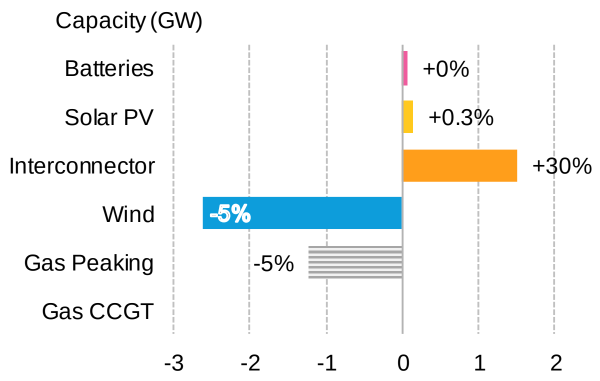
In addition, the interconnector acts as a flexible generator, it reduces to some extent the need for batteries and helps integrate slightly more wind capacity, about 0.5GW, by 2040. However, by 2050 there is less need for wind power, which otherwise would be preferred by the system thanks to its more stable output through day and night-time hours. As a result, the added interconnector capacity results in a reduction of 2.6GW for wind by 2050. Solar capacity is virtually left unchanged throughout the projection.

Figure 47: 2040 generation capacity change for interconnection scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 48: 2040 generation capacity change for interconnection scenario, versus base case

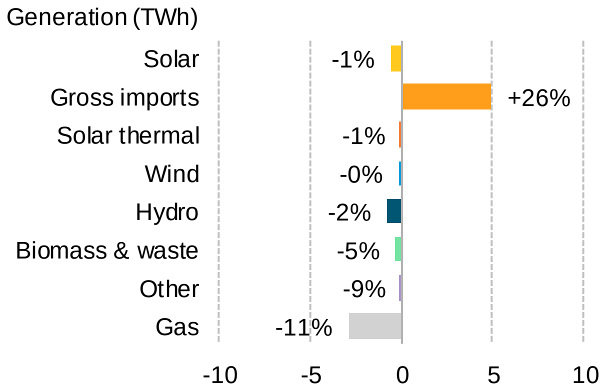


Source: BloombergNEF. Note: percentages show relative change against the base scenario

From a generation point of view, having the ability to tap into a different market means less gas generation is needed – a figure that is valid for both 2040 and 2050. However, the reduction in wind capacity in the long term also translates to less wind generation, which is partly replaced with gas.

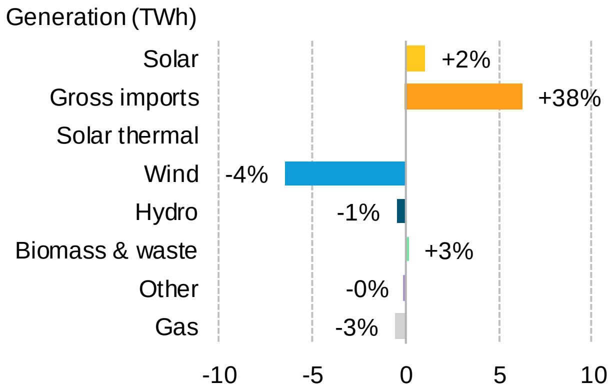
Although there is almost no change in solar capacity against the base scenario in 2050 (just 0.3%), the flexibility from interconnection helps accommodate 2% more solar generation in the same year. This this doesn't occur in 2040 where there is more wind capacity. In any case, there are sunny and windy times when there is far more excess variable renewable power than the lines are able to transport. (Figure 49 and Figure 50).

Figure 49: 2050 power generation change for interconnection scenario, versus base case



Source: BloombergNEF. Note: percentages show relative change against the base scenario

Figure 50: 2050 power generation change for interconnection scenario, versus base case

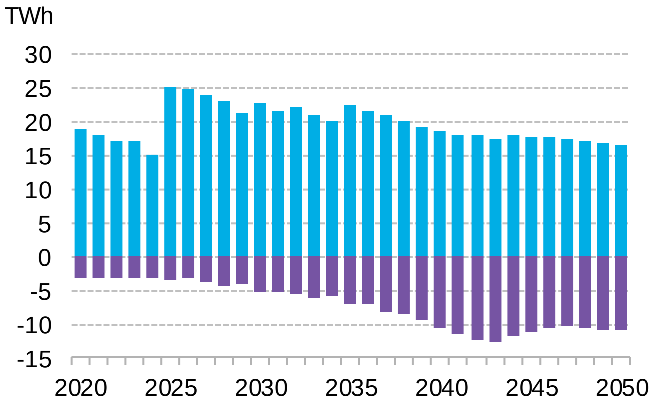


Source: BloombergNEF. Note: percentages show relative change against the base scenario

Another important aspect is how the interconnection capacity is utilized: which way does the power flow and how often is it used? As we progress through the forecast period, and more wind and solar are installed in both Spain and France, the role of the interconnector changes.

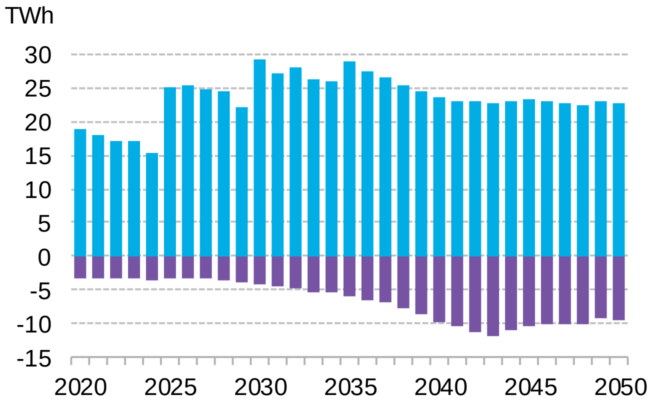
- In 2020, interconnector use is nearly unidirectional, with power flowing from France into Spain 86% of the time. This is mainly driven by cheap nuclear generation from France. As Spain builds more zero short-run marginal cost capacity, imports from France start falling but there is no significant increase in Spanish exports, since France has little need to import power.
- In 2025, when the Biscay Gulf interconnector comes online and transmission capacity increases between the two countries, imports into Spain from France grow again. However, they proceed to drop year-on-year as more wind and solar are installed in Spain.
- In the base scenario, peak imports occur in 2025 (Figure 49). From this point on, Spain becomes more reliant on its own generation to meet demand. Spain also begins exporting more from 2025 onwards, as periods when wind and solar over-generate become more frequent and as France retires a fraction of its nuclear fleet. We see Spanish exports peaking in 2043. Line utilization in this scenario averages 65% over 2030-50.
- Under the high-interconnection scenario, we see an increase of 1.5GW of interconnection capacity in 2030, at which point imports from France reach their maximum of 29TWh. Imports from France oscillate around an average of 27TWh over 2030-40. In 2040, imports drop to 23TWh and remain at that level out to 2050 (Figure 52). Despite the additions in interconnector capacity, exports from Spain into France remain at similar levels in both scenarios, peaking in 2043 at 12TWh. This means overall line utilization is 9% lower in the high-interconnection scenario, averaging 58% over 2030-50.

Figure 51: Flows between France and Spain in base scenario



Source: BloombergNEF

Figure 52: Flows between France and Spain in high-interconnection scenario



Source: BloombergNEF

The limits to how much Spain can export to France seem to be less related to interconnector capacity and more to the need for power in France.

These dynamics reflect the changing nature of a system driven by vast wind and solar capacity that often generates more than it needs. More importantly, it reflects how the value of the interconnection to France shifts partially, from acting as a source of generation to Spain to increasingly becoming a source of demand. However, the limits to how much Spain can export to France seem to be less related to interconnector capacity and more to the need for power in France.

8.2. Implications, benefits and drawbacks of this scenario

More interconnection capacity does reduce emissions, since most imports from France come from nuclear or renewable generation.

Increased interconnection to France has negligible impact on system costs. In the short term, overall system costs are 1% higher, but over 2040-50 the system becomes 1% cheaper (Table 14). The increased interconnection capacity does contribute to reducing carbon emissions, since the vast majority of imports from France come from nuclear or renewable generation. This means that over 2030-40, emissions are 6% lower, equivalent to 13MtCO2 less than in the base scenario. From 2040-50, they are 8% below those in the base scenario, amounting to a 12MtCO2 cumulative reduction.

From a reliability perspective, the extra interconnection capacity reduces the dependence on fossil peaking plants by about 4%, albeit with increased exposure to French power prices.

As France and Spain see greater volumes of cheap wind and solar capacity installed, imports and exports become more balanced.

As the French and Spanish systems see greater volumes of cheap wind and solar capacity installed, imports and exports become more balanced. However, more interconnection capacity does not result in greater exports from Spain to France than in the base scenario. This is because there are times when France does not need imports from Spain, even if they are virtually free, since wind and solar over generation can occur in both countries simultaneously.

Table 13 and Table 14 summarize the key metrics for the scenario and compares them to the base scenario.

Table 13: Key metrics for the interconnection scenario

Metric	Units	2030		2040		2050	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
System cost	$/MWh	41.2	-0.4	45.6	-0.7	52.1	0.4
System cost	$bn	11.8	-0.1	13.9	-0.2	16.4	0.1
Emissions	MtCO2	20	-1	16	-2	12	0
Fossil capacity as share of peak demand	%	68%	-3%	61%	-3%	58%	-3%
Renewable share of generation	%	67%	-1%	84%	-1%	87%	-2%
Zero-carbon share of generation	%	84%	1%	92%	1%	95%	0%

Source: BloombergNEF

Table 14: Key cumulative metrics for the interconnection scenario

Metric	Units	2020-30		2030-40		2040-50	
		Value	Change vs base	Value	Change vs base	Value	Change vs base
Average system cost	$/MWh	36.3	0.5	45.0	0.6	48.3	-0.4
System cost	$bn	110.7	1.4	147.3	2.0	164.6	-1.2
Emissions	MtCO2	277	3	190	-13	151	-12
Average fossil capacity as share of peak demand	%	76%	0%	66%	-2%	60%	-3%
Average renewable share of generation	%	56%	0%	76%	-1%	85%	-1%
Average zero-carbon share of generation	%	80%	0%	88%	1%	93%	1%

Source: BloombergNEF

Section 9. Final thoughts

This section presents some overall observations and findings from across the scenarios, and the lessons they provide as Spain transitions to a future power system dominated by renewables. We also provide a comparison of the six scenarios – though we do this with some caution. This report is not intended to 'pick a winner' from the technologies analyzed – all of these technologies will play a role – but comparing scenarios does provide insight into their relative contributions and roles.

9.1. Roles and contributions of each technology

The tables below compare the main outcomes for each technology scenario in 2040 and 2050.

Table 15: Summary of scenario outcomes over 2020-30

Scenario	Average system cost	System cost	Emissions	Average fossil capacity as share of peak demand	Average renewable share of generation	Average zero-carbon share of generation
Base case	$35.86/MWh	$109.36bn	274MtCO2	77%	56%	80%
Relative change vs base scenario						
Low-flex	0%	0%	3%	0%	-1%	0%
EV	0%	0%	3%	0%	-1%	-1%
EV flex	0%	-1%	2%	-1%	-1%	0%
Storage	-1%	-1%	0%	-1%	-1%	-1%
Interconnector	1%	1%	1%	0%	-1%	0%

*Source: BloombergNEF. Note: Color scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Table 16: Summary of scenario outcomes over 2030-40

Scenario	Average system cost	System cost	Emissions	Average fossil capacity as share of peak demand	Average renewable share of generation	Average zero-carbon share of generation
Base case	$44.37/MWh	$145.24bn	203MtCO2	69%	77%	87%
Relative change vs base scenario						
Low-flex	1%	1%	2%	6%	1%	0%
EV	3%	4%	-2%	2%	-1%	-1%
EV flex	0%	2%	-9%	-1%	0%	0%
Storage	0%	0%	-1%	-6%	-2%	0%
Interconnector	1%	1%	-6%	-4%	-1%	1%

*Source: BloombergNEF. Note: Color scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

Table 17: Summary of scenario outcomes over 2040-50

Scenario	Average system cost	System cost	Emissions	Average fossil capacity as share of peak demand	Average renewable share of generation	Average zero-carbon share of generation
Base case	$48.63/MWh	$165.87bn	163MtCO2	63%	86%	93%
Relative change vs base scenario						
Low-flex	4%	3%	11%	16%	0%	-1%
EV	9%	21%	-41%	16%	-3%	-3%
EV flex	3%	14%	-64%	8%	-1%	-1%
Storage	-4%	-4%	-12%	-13%	0%	1%
Interconnector	-1%	-1%	-8%	-4%	-1%	1%

*Source: BloombergNEF. Note: Color scales differ between columns, but in all cases green is desirable. *Emissions for EV scenarios include a negative contribution from emissions displaced in the oil sector.*

The lowest-cost Spanish power system is driven mainly by wind and solar.

In our base scenario, by 2030, these technologies supply 51% of generation – 33% and 18% of total generation supplied by wind and solar, respectively. By 2050 they generate 75% of electricity. Although ambitious, it is worth noting that our base scenario falls short of Spain's National Energy and Climate Plan 2030 targets. Our base scenario achieves 68% renewable electricity generation in 2030, six percentage points below Spain's targets. It also falls short by 20.7GW of wind and solar capacity.

Across all scenarios, low-carbon technologies drive Spain's power sector.

The scenario outcomes differ in system cost and emissions, but in all cases, renewable energy achieves over 80% of the electricity mix by 2030, and at least 90% by 2050. This reinforces our findings that wind and solar are the cheapest forms of power generation and will come to dominate the future generation mix. In modelling terms, their cost-effectiveness makes them the number one choices for power supply, regardless of how the flexibility challenge is solved.

The system will be more expensive without 'new' sources of flexibility.

Throughout the scenario timeframe, the low-flex scenario scores worse than the base scenario across all metrics. The lessons are clear: in a world where new forms of flexibility do not realize their potential, the power system has to adapt in other ways to maintain reliability and provide the flexibility to complement renewables. This means a greater reliance on gas peakers, leading to higher system costs, higher emissions and a greater level of back-up capacity. Power sector emissions are 6% higher over 2030-40, and 20% higher over 2040-50 under this scenario.

Flexible charging is key to electrifying transport at the lowest cost.

Even in our high-uptake scenario, where nearly all road transport is electrified by 2050, EVs do not 'break' the power generation system. System costs, in terms of generating capacity and electricity produced, are raised just 4% and 15% in 2040 and 2050 respectively on a per-MWh basis, and this is before considering avoided fuel costs. The fossil fuel capacity share is raised by 29%, or 8GW, in 2050 (and by just 6% in 2040). However, impacts on the transmission and distribution network may be more significant – see discussion below.

Adding more EVs by 2050 of course leads to higher electricity demand and therefore higher emissions in the power sector, but once we net off the emission reductions from gasoline and diesel savings (which we have done in the tables above), the overall emission savings are substantial. Our high-EV scenario has 41% better cumulative emissions performance over 2040-50 than the base case on this basis.

In our high-uptake, high-flexibility EV scenario, the results are even better, with cumulative net emissions down 64% over 2040-50. The fact that EV charging load can be shifted throughout the day results in only a 7% increase in per-MWh system costs (versus 15% in the high-EV scenario) and it halves the need for extra fossil back-up. This underscores the benefits of developing a strong base of charging infrastructure at workplaces, commercial destinations and residential buildings that can charge responsively depending on pricing and grid conditions.

Battery storage developments could lead to a cheaper, cleaner system, but fossil capacity is still needed.

The base case already includes a significant share of energy storage, but in a scenario where storage gets even cheaper, the outcomes are striking. By 2050, fossil back-up can be reduced by 13% relative to the base case, and emissions by 12%, through displacement of gas peakers by battery plants reaching a zero-carbon generation penetration of 95% and a 4% reduction in costs. This effectively accelerates the energy transition by moving Spain more rapidly down the emissions reduction curve.

Across all scenarios, fossil capacity makes up no less than half of peak demand. As CCGTs retire, peaking gas capacity additions ensure that the level of fossil capacity remains fairly constant throughout the projection. In the absence of technologies like hydrogen or CCS, this firm capacity is needed to deal with the weeks and months of low renewables production. This is the case even in the low storage-costs scenario, which has the lowest level of fossil fuel utilization, but still generates 5% of its electricity from gas.

Interconnectors help reduce emissions but their flexibility can be undermined by renewables.

Increasing interconnection to France helps reduce emissions, with little impact on costs. However, as the French and Spanish systems see greater volumes of cheap wind and solar capacity installed, the utilization of the interconnector falls. This is because there are times when France does not need imports from Spain, or vice versa, since wind and solar over-generation increasingly occurs in both countries simultaneously, limiting the flexibility of the interconnection.

Relying on wind and solar generation reduces energy imports and price exposure.

Comparing results across different scenarios, we see that certain technologies like battery storage – or a lack thereof – vary the degree of dependence on gas and electricity imports. For example, the high energy-storage scenario results in a long-term reduction in gas generation and electricity imports from France. This increases Spain’s ability to meet demand with its own resources and reduces the sector exposure to commodity prices and other risks associated with importing energy. Conversely, the low-flex scenario increases reliance on gas generation, which relies on imports and thus heightens exposure to commodity prices. The high-interconnector scenario trades off gas imports for electricity imports, reducing exposure to gas prices. This is only a partial effect, however, since power prices in France, which is well interconnected to Germany and other large European markets, are still impacted by gas prices.

A system powered by wind and solar requires careful market design

In a system with rising penetration of wind and solar power, prices tend to decline, lowering market revenues for all generators and especially for wind and solar projects. Despite declining costs, this dynamic undermines the investment case for such projects. In turn, this renders much more difficult the achievement of systems mainly powered by wind and solar, such as the Spanish scenarios in this report. In short, most technologies, including wind and solar, will not be able to rely purely on energy-only market-based revenues, even when they are very cheap.

As such, for this scenario to materialize, there would have to be careful market design to provide the right price signals. Policymakers and regulators can help to bring about these outcomes by removing barriers and creating a favorable market environment for flexibility sources.

These could include, for example:

- the introduction of dynamic power pricing (potentially mandatory) for energy customers – and for electric vehicle charging;
- lower barriers for participation, across capacity, energy and balancing markets
- the establishment of frameworks for distribution network operators to share the value of flexibility;
- greater incentives or compensation for rapid-responding resources within capacity and ancillary markets;
- shortening of the trading and settlement interval in the wholesale power market; and,
- expansion of market access for energy storage and demand-side resources – including aggregated resources.

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