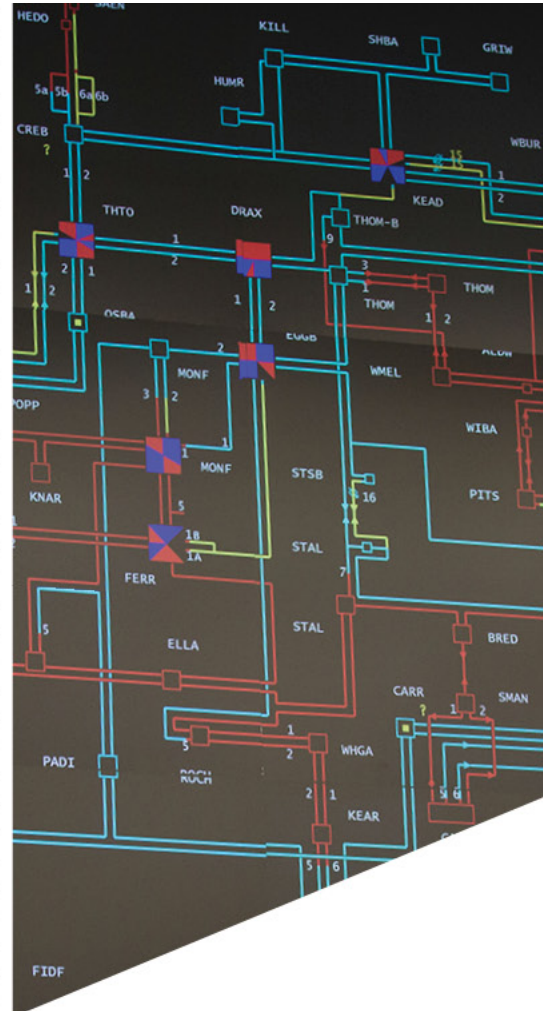


February 2020

Sector Coupling in Europe: Powering Decarbonization

Potential and Policy Implications
of Electrifying the Economy



BloombergNEF

EATON

Powering Business Worldwide

 **Statkraft**

Contents

Foreword	1
Executive summary	2
Introduction	7
Part 1: Sector coupling pathway	11
Section 1. Overview	12
Section 2. Sector coupling pathway in brief	13
Section 3. Impact on electricity demand and supply	16
3.1. Power demand	16
3.2. Capacity build and power generation	18
Section 4. Pathway method and assumptions	20
4.1. Economics	20
4.2. Policy	21
4.3. Other factors	23
Part 2: Impact of sector coupling on power system	25
Section 5. Overview	26
Section 6. Power generation	27
6.1. Investment signals and missing money	27
6.2. Impact of sector coupling	29
6.3. The risk of 'dirty' sector coupling	30
Section 7. Flexibility and demand	32
7.1. Flexible technologies	32
7.2. Impact on demand profiles	35
7.3. Implications	39
7.4. Investment signals and other barriers	43
Section 8. Grid	45
8.1. Electricity grid	45
8.2. Gas grid	51
Part 3: Implications for policy and regulation	53
Section 9. Overview	54
Section 10. Enabling sector coupling	57
10.1. Emission policy	57
10.2. Energy taxes	58
10.3. Public acceptance of wind and solar build	59
10.4. Hydrogen	61

	10.5. Energy efficiency	62
Section 11.	Unlocking demand-side flexibility	64
	11.1. Flexible tariffs	64
	11.2. Allocation of wholesale price risk and granularity of price signal	69
	11.3. Technological readiness	70
	11.4. Market access	70
Section 12.	Making the best use of power networks	73
	12.1. Network expansion and interconnection	73
	12.2. Network optimization	74
	12.3. Data exchange and forecasting	77
Section 13.	Facilitating power-gas integration	79
	13.1. Hydrogen electrolyzer siting	79
	13.2. Legal and technical barriers	80
	13.3. Public acceptance of hydrogen	81
Section 14.	Strengthening investment signals for generation and flexibility	82
	14.1. Investment signals for generation	82
	14.2. Revenue certainty for flexible resources	85
Appendix A.	Sector coupling pathway – in detail	89
Appendix B.	Assumptions	103
About us		106

Foreword

Electrification has been at the core of human progress and economic development since the industrial revolution. It has improved livelihoods, spurred innovation and improved efficiency across all sectors of our economy and aspects of our lives. It has been the hallmark of progress. What is now happening is merely the next phase, where electrification reaches further and deeper into the transportation, building and industry sectors. The advantages are many, and as before, it will transform both our economies and our societies.

In Norway, affordable and clean hydropower combined with government subsidies has resulted in a record high level of electrification in all these sectors, and Statkraft is an important part of that. However, driving this sector coupling on a broad scale throughout Europe will be challenging and will require willingness to take bold political action with regulations covering the whole energy system. There are clear benefits of sector coupling; It is by far the most efficient way to decarbonise Europe, it increases the energy efficiency of our economies and cleans up the air in our cities.

This report provides insights into how this can be achieved in the form of realistic pathways for each sector. It highlights both the scale of the change and the challenges they pose, and in particular the need for a forward leaning policy reform agenda.

Henrik Sætness, SVP Strategy & Analysis, Statkraft

Europe's ambition to realize deep decarbonization of its economy requires that electricity generated from low- or zero-carbon sources becomes the main source of energy.

Fortunately, rapid technological advances, standardization and increasing adoption all continue to drive down the cost of green technologies, making them cost competitive against their fossil-fuel-era predecessors. However, this is not enough.

The findings of this important study clearly demonstrate the need for the foundational work that remains to be done in order to accelerate the energy transition and halt the accumulation of greenhouse gases in the atmosphere, touching all aspects of the energy ecosystem.

While essential reform to grid regulation has started to progress across Europe, we have far to go if we are to replicate best practices and further encourage innovation. This is particularly apparent when it comes to market structures that incentivize the flexibility needed to address the challenge of renewable intermittency.

Short-term variability can eventually be addressed with existing technologies – if properly compensated. However, we will also need long-term storage for periods of low renewables production. Technologies such as clean hydrogen production and transport remain expensive. Long-term energy storage from green hydrogen and technologies such as carbon capture require government support for large-scale research and development and pilot programs to accelerate cost reductions.

We have already seen that even when green technologies mature and reach cost parity, adoption takes time as consumers, business and society take time to adapt. Government policy and regulations are required to speed up adoption. The benefits for job creation, reduced pollution, and meeting emission targets will be massive, and early adopters will benefit most.

This report highlights many such policy challenges and trade-offs, and offers practical ideas for policy-makers and businesses so they can fulfil their roles in aiding the rapid transition to a low-carbon economy.

Cyrille Brisson, VP Sales, Service and Marketing, Eaton EMEA

Executive summary

50-60%

Share of energy use from electricity for transport, buildings and industry by 2050 in a country like U.K. or Germany

71%

Potential emission reduction below 1990 levels by 2050 across transport, buildings and industry due to sector coupling

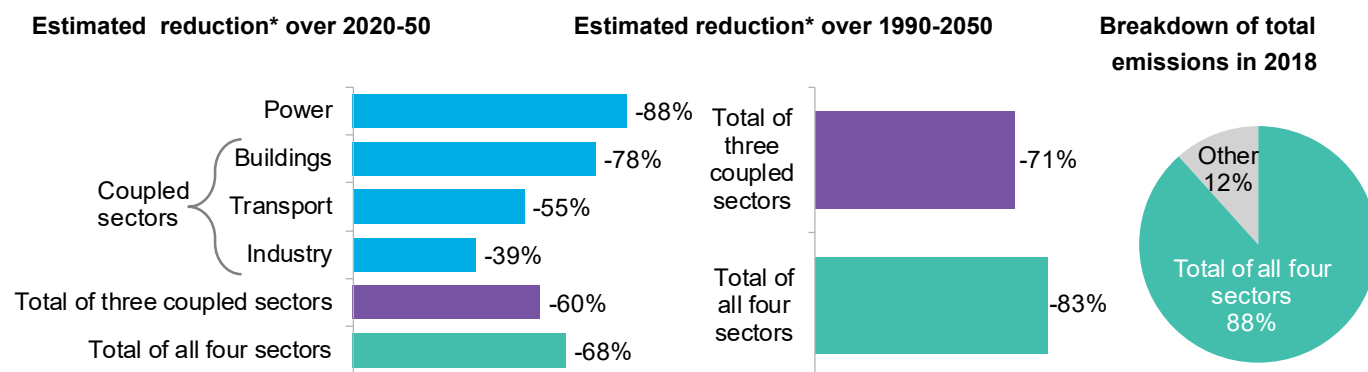
83%

Potential emission reduction below 1990 levels by 2050 across transport, buildings, industry and power due to sector coupling

‘Sector coupling’ – ie, the electrification of more areas of the economy – would enable countries in Europe to make substantial progress toward becoming the first climate-neutral continent by 2050. This report, authored by BloombergNEF in partnership with Eaton and Statkraft, explores how the transport, buildings and industrial sectors in Europe could be electrified by plugging them directly into the power grid or switching to green hydrogen produced from renewables (indirect electrification). Its particular focus is the impact of sector coupling on the electricity system and market design, and highlights how policy makers and regulators could address some of the biggest challenges.

1. **Sector coupling – ie, the electrification of transport, buildings and industry – would make a significant contribution to climate goals (Figure 1).** It would enable these sectors to shift away from dependence on fossil fuels and toward the power system, which has already made great strides toward decarbonization.
 - By 2050, the generation mix in a country like the U.K. or Germany almost fully switches to low-carbon technologies thanks to cheap renewables, according to BNEF analysis. As a result, sector coupling could lower emissions by 60% over 2020-50 across transport, buildings and industrial. This would equate to a 71% reduction on 1990 levels.
 - Sector coupling may increase the greenhouse-gas output for the electricity sector itself because more fossil-fuel-fired plants are needed to provide sufficient flexibility to the system. However, economy-wide emissions will still be significantly lower because transport, buildings and industry switch away from fossil fuels. In particular, by 2030, the coupled sectors together with electricity could cut emissions to 63% below 1990 levels compared with the EU legislated target of 40%. By 2050, this reduction would extend to 83% below 1990 levels.

Figure 1: Greenhouse-gas emissions with sector coupling in a country like U.K. or Germany (known as the ‘Northern European archetype’)



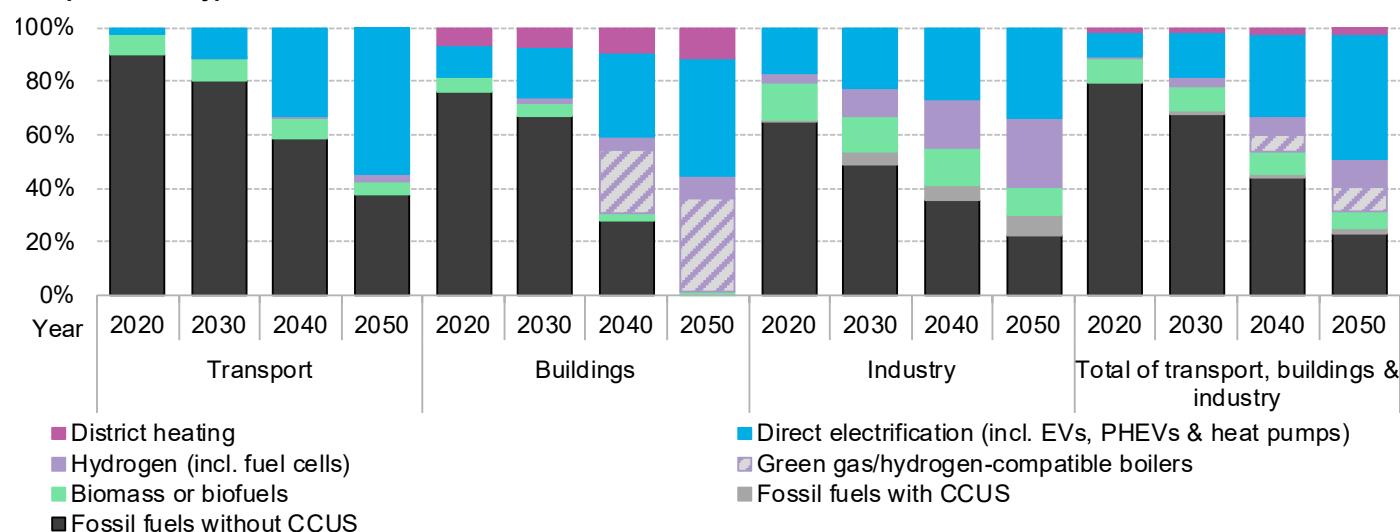
Source: BloombergNEF based on conversion factors from the U.K. government. U.K. and German government for 2018 breakdown. Note: * Emission estimates assume that all compatible boilers in buildings are fueled by green gas or hydrogen.

- Sector coupling makes a major contribution toward net zero, but will not deliver this goal on its own. Policy makers would need to tackle the hardest-to-abate sectors such as aviation, shipping, long-haul road transport and high-temperature industrial processes - these are likely to require other solutions such as 'blue' hydrogen, CCUS¹ and bioenergy. Agriculture and land use would also need to be addressed.

2. Electricity could provide a substantial share of energy used in Europe by 2050, to the detriment of fossil fuels (Figure 2). A plausible sector coupling trajectory or 'pathway' for a country like the U.K. or Germany envisages that power (directly or indirectly) supplies 50-60% of the final energy consumed by the coupled sectors by 2050 – up from around a tenth today. The share of unabated fossil fuels drops from nearly 80% to 23%.

- This pathway is based on BNEF's analysis of technology costs and carbon pricing, together with our view of likely policy action for governments to achieve their climate ambition. Note that on this basis, that plausible sector coupling pathway does not fully eliminate greenhouse-gas emissions from transport, buildings and industry by 2050.
- The speed of progress varies across the coupled sectors: transport has already begun electrification, driven by government support and the growing cost competitiveness of road-going electric vehicles (EVs). However, our pathway shows the buildings sector could overtake transport in terms of electrification by 2050. We see little progress away from fossil fuels for long-haul and heavy road transport, aviation and shipping.
- In industry, sectors with lower-temperature processes (eg, food & drink) switch to electrification technologies earlier and to a greater extent. Technological barriers mean that the hardest-to-abate industrial sectors (eg, iron & steel, and cement), which require very high temperatures, still rely on unabated fossil fuels for some 40% of energy use by 2050. However, they do see a marked increase in the use of hydrogen, as electrolysis using renewables reaches cost parity with fossil fuels for some processes, based on BNEF's carbon-price outlook.

Figure 2: Breakdown of energy consumption by fuel source across transport, buildings and industry in the Northern European archetype



Source: BloombergNEF. Note: Weighted by each sector's energy consumption in the Northern European archetype (Eurostat).

¹ CCUS is carbon capture, use and storage. Blue hydrogen is produced by methane reforming, with CCUS.

3. Sector coupling is a massive undertaking that will not happen without policy action.

While some of the necessary policy measures are in active discussion, most are not yet implemented or require more detailed work. If sector coupling is to proceed along our pathway:

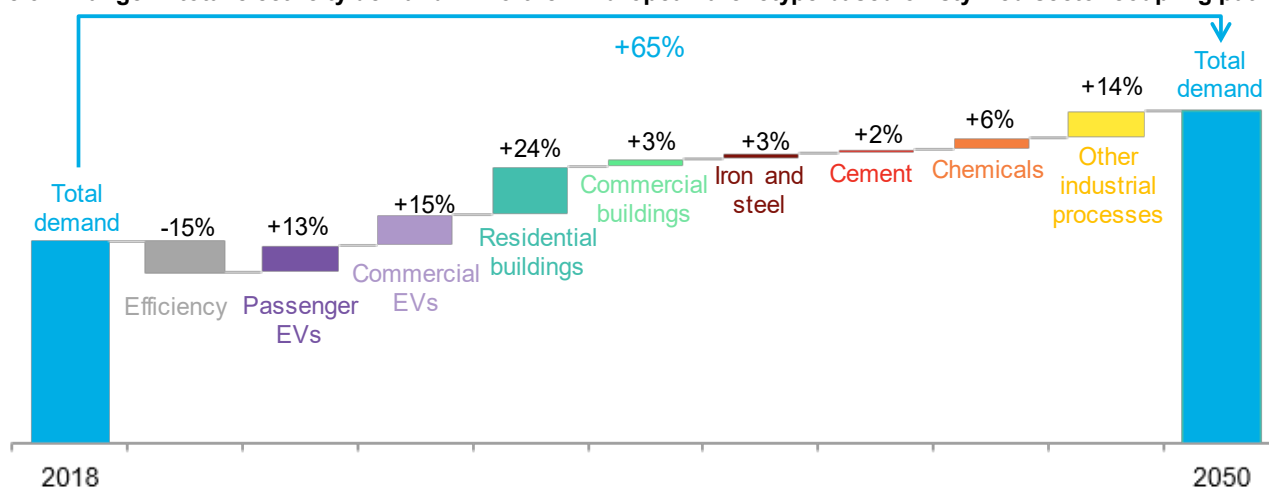
- The sectors to be electrified must be incentivized to reduce emissions. These incentives are already in place, to some extent, for the transport and industrial sectors through the European Emission Trading System and other targets. But to make possible sector coupling, policy makers would have to introduce similar measures for building heat. Our pathway envisages various types of command-and-control regulation, but carbon pricing and financial incentives are other options.
- Policy makers would need to support early efforts to demonstrate the viability of electrification in the coupled sectors. Focus should be given to projects bringing together all components of an integrated energy system with sector coupling, and to incentives for communities and companies to be early movers.
- Governments also have a role to play in creating a market for green hydrogen, to drive down electrolyzer costs. As hydrogen is crucial to sector coupling, energy policy makers and regulators should seek to facilitate the increased crossover between the power and natural gas systems, and work to reduce technical and regulatory barriers to the injection of hydrogen into the gas grid.

Impact of sector coupling on the power system

4. Significant levels of sector coupling require a substantially larger power system

(Figure 3). In our pathway, by 2050 electricity demand in a country like the U.K. or Germany is nearly double what it would be without sector coupling. (Note that this equates to a 1.3% compound annual growth rate over 2018-50 – within the historical range of electricity demand growth. The EU saw an increase of 1.4% a year between 1990 and 2010, for example.) This additional demand requires some 75% more generating capacity, with nearly double the amount of wind and solar build needed. The additional electricity demand under our pathway raises spending on new generation and battery storage capacity by two-thirds over 2018-50. Sector coupling may help unlock potential synergies: for example, heat pumps may be used to cool a data center and the excess heat delivered to a district heating network.

Figure 3: Change in total electricity demand in Northern European archetype based on stylized sector coupling pathway



Source: BloombergNEF. Note: The waterfall chart includes direct and indirect electrification. Excludes the minor volume of power demand from aviation, shipping and district heating.

5. The power system will need to become more flexible but sector coupling will also create new sources of flexibility.

- Due to the different energy consumption patterns of the coupled sectors, the intraday and seasonal load profiles are higher and steeper with sector coupling, principally due to the electrification of transport and buildings. This – as well as the increased wind and solar generation – will require more flexible resources such as battery storage and gas peaker plants.
- The scale of the challenge for the power system depends on the uptake of the new sources of demand-side flexibility created by sector coupling. The potential new sources of flexibility include ‘dynamic’ electric vehicle (EV) chargers and electric heating systems that respond to pricing signals, virtual power plants and industrial demand response – if the right enabling policies and technologies are in place. More dynamic demand means less investment in generation and storage capacity and the electricity grid, lower system costs and lower power emissions.

6. The success of sector coupling is particularly dependent on how electricity-grid-related issues are managed. The electricity network will need reinforcement and extension in the long term due to the increased power flows. If the demand growth path were relatively smooth, the compound annual growth rate would be well within the historical range. However, in practice the upward trend will likely be steeper from 2030 and unevenly spread across the network as certain areas connect EVs or heat pumps before others. Grid operators have also relatively little visibility on the uptake of these electrification technologies.

7. The power and gas systems will become more integrated, as more hydrogen produced from electrolysis is fed into the gas network. It will be crucial for electricity and gas grid operators to work with hydrogen producers and consumers on where to site electrolyzers. The best locations are likely to have good connections to both the power and gas network (or hydrogen demand clusters). We expect countries to use the natural gas grid for hydrogen transport in the short-to-medium term as injecting a limited blend of hydrogen would require relatively minor upgrades. Repurposing the gas grid to transport hydrogen would have the double benefit of reducing stress on the power network and extending the useful life of the gas network itself. Switching to a 100%-hydrogen grid would require the gas network and appliances to be upgraded or replaced. This would not be straightforward and would likely be undertaken in localized clusters rather than countrywide networks.

8. Energy consumers and civil society have a crucial role to play in making possible a smooth sector coupling for the power system. Their engagement and buy-in are not a given. For example, the construction of the required new power plants and network infrastructure could be jeopardized if the current trends of public opposition and litigation continue. In addition, consumers directly affect the scale of impact of sector coupling through their uptake of technologies such as electric vehicles, and the timing of their electricity consumption.

Recommendations for policy makers and regulators

9. Policy makers need to ensure the availability and uptake of flexible electricity tariffs, with strong incentives for all consumers to minimize net peak demand. This is because maximizing the volume of demand-side flexibility in the power system will be crucial to a successful sector coupling. As such, future tariffs will need to encourage users to shift consumption to times of renewables availability and to alleviate network constraints. Priority should also be given to the standardization and interoperability of the smart systems that are rolled out with sector coupling to provide the billing infrastructure for these tariffs.

- 10. Government support and regulatory changes are needed in order to ensure the electricity network is able to deal with the effects of sector coupling.** Government and industry players should collaborate to tackle one of the biggest hurdles for increased electrification: public acceptance of grid extension. Options include awareness-raising campaigns together with compensation and other incentives for local communities. To reduce the volume of required grid investment, policy makers could implement more locational pricing signals and promote digitalization and interconnection. Grid operators at the distribution level should move more quickly to take on the responsibilities of a 'distribution system operator' and should be incentivized to take a more active role in flexibility procurement locally, to facilitate a smooth sector coupling.
- 11. Regulators and policy makers play a key role in facilitating the integration of the power and gas systems.** For example, the issue of optimal siting for hydrogen electrolyzers could be addressed through research funding and initiatives such as the development of clusters. In addition, technical and legal barriers to hydrogen use in the gas grid will need to be addressed. Demonstration projects will help develop understanding of these, and awareness-raising initiatives will be needed to boost public acceptance of hydrogen heating due to safety concerns and the eventual need for upgrade works.
- 12. Policy makers will likely have to amend capacity mechanisms or implement additional revenue streams, to maintain the pace of power-system decarbonization.** Otherwise, sector coupling may result in additional fossil-fuel build, leading to higher emissions. Options include incentives for excess renewable power to be converted into hydrogen to be stored and used at a later date; or for the newly coupled sectors to sign long-term renewable power purchase agreements to reduce generators' exposure to wholesale electricity price fluctuations. Policy makers will also have to ensure that flexible technologies such as battery storage are properly incentivized and that they may participate fully in the power market.

Introduction

In countries across Europe, policy makers and industry are setting ambitious goals to reduce greenhouse-gas emissions – in many cases to net zero. The power sector has already begun to decarbonize but others such as transport, industry and buildings – all major consumers of fossil fuels – have lagged behind.

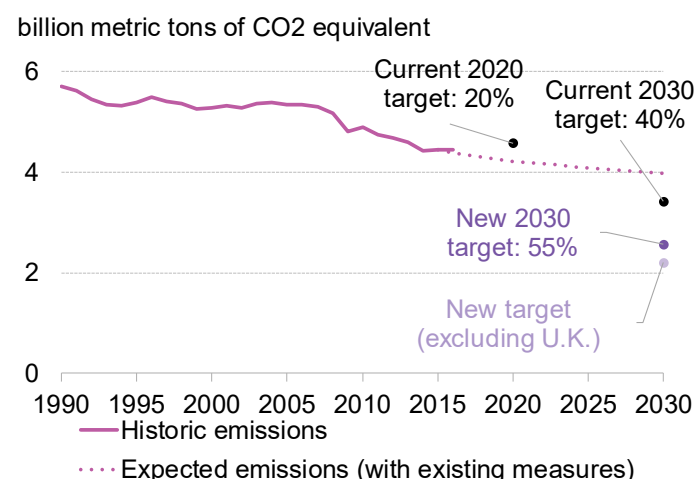
A credible way to decarbonize these sectors is to exploit the headway made by the power system, and electrify as many areas of the economy as possible – by directly switching them to electric power, and/or fueling them from green hydrogen (produced by electrolysis) or other fuels produced from power. This process is defined as ‘sector coupling’.

This report, authored by BloombergNEF in partnership with Eaton and Statkraft, lays out a pathway for sector coupling in archetypal European countries, analyzes the impact of coupling on the power system, and highlights the key policy considerations that must be addressed for successful coupling.

Context

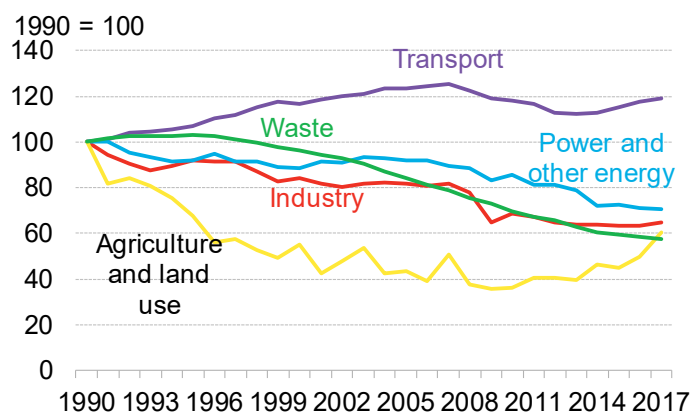
Decarbonization of the power sector has already begun, thanks to policy support and declining renewables technology costs. As a result, wind and solar electricity generation in Europe rose 75% over 2012-18, helping emissions for the power sector decline 22% over the same period. However, as policy makers make increasingly ambitious climate pledges, attention is now moving beyond the power system to the whole economy. European countries, including the EU, its member states and the U.K., are parties to the Paris Agreement, which includes the goal to keep the increase in the global average temperature to well below 2 degrees Celsius above pre-industrial levels and as close as possible to 1.5 degrees Celsius.

Figure 4: Annual EU greenhouse-gas emissions and targets



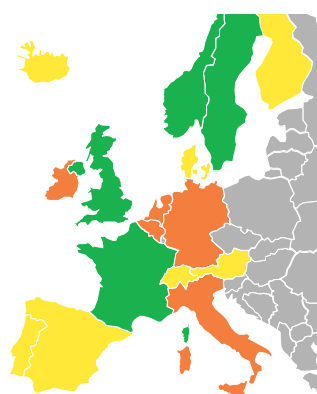
Source: European Commission, European Environment Agency, BloombergNEF

Figure 5: EU historical greenhouse-gas emissions



In addition, the European Green Deal, unveiled in December 2019, proposes a new target to reach net-zero emissions and become the first climate-neutral region by 2050. This would entail a rapid cut in greenhouse-gas output, raising the EU's current 2030 target from a cut of 40% to 50-55% below 1990 levels (Figure 4). This proposal will be included in the EU's first climate law, due for release in spring 2020, and will need to pass the formal legislative process.

Figure 6: Status of national net-zero emission targets in Europe



Legend

- Legislated
- Policy announced
- In discussions

Source: BloombergNEF

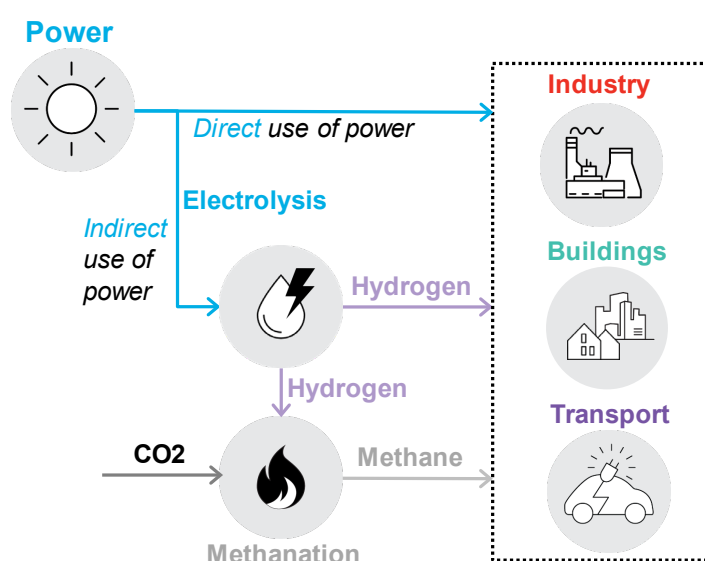
Some national governments are making similarly ambitious commitments: 12 European countries have net-zero targets either legislated or proposed in government policy (Figure 6). Together these cover almost half of European emissions in 2018.

To realize these ambitions, decarbonization efforts will need to move beyond the power system. Indeed, current EU policies will only reduce emissions by 60% by 2050, according to European Commission estimates. However, historically other sectors have made less progress than electricity: for example, transport emissions in the EU climbed 6% over 2012-17 while those for industry rose just under 0.5%. (This increase would have been larger without the decline in heavy industry in the EU.) In contrast, over the same period the power sector saw its greenhouse-gas output drop by nearly a fifth.

And there have been good reasons why it has been more difficult to decarbonize these 'laggard' sectors. Take the case of buildings: the EU has hundreds of millions of properties requiring heating and hot water. These properties mostly have different owners, who are often not the occupants. In contrast, at the end of 2000 – around the start of the current energy transition – the bloc had just over 3,000 power plants, with around 30 companies owning half of the generation capacity.

In this context, the increasingly low-carbon power system has opened up a new route to deep decarbonization: 'sector coupling' (Figure 7). This report focuses on the nearest candidates for electrification – transport, together with heating for buildings and industry – and considers the impact of plugging these sectors into the power grid (direct electrification) or shifting to green hydrogen produced through electrolysis (indirect electrification).

Figure 7: Illustrative diagram of sector coupling



Source: Robinius, M.; Otto, A.; Heuser, P.; Welder, L.; Syranidis, K.; Ryberg, D.S.; Grube, T.; Markewitz, P.; Peters, R.; Stolten, D. Linking the Power and Transport Sectors—Part 1: The Principle of Sector Coupling. *Energies* 2017, 10, 956.

Sector coupling therefore not only links the end-use sectors such as transport with the power system but it also boosts the interaction between the electricity and gas systems. It will therefore have significant repercussions for the power sector, which is already undergoing major changes.

Challenges faced by the power system include how to incorporate enough flexibility into the market, how to enable distributed energy resources to realize their potential, and how to ensure that investment signals are adequate to make possible the energy transition.

These challenges, shown in Table 1, are associated with the transition to low-carbon power and will have to be addressed whether or not sector coupling takes place. However, sector coupling will affect these challenges (in some cases exacerbating them, in others mitigating them) – and also introduce new challenges.

Table 1: Key power system problems

1	The power sector may fail to deliver a clean and reliable supply of electricity because the wholesale market does not offer credible signals for investment in renewable and dispatchable capacity. This is the 'missing money' problem.
2	The growing share of variable generation in the mix makes it more difficult for the system operator to balance the market, and increases the need for short- and long-term flexibility.
3	Not all sources of flexibility (large-scale or distributed) are adequately valued and remunerated.
4	The increase in distributed energy resources on both demand and supply side creates challenges for grid management.
5	The grid already faces challenges due to the geographic mismatch between the location of energy resources or generating capacity, and demand centers. Such challenges are set to worsen at a local level with the growth in ICT or other industrial clusters.
6	A power market needs to encourage technological innovation and ensure future-proofing.
7	Sector coupling will substantially increase total electricity demand over the next 30 years even in markets where demand would otherwise flatten out or decline. This may be beneficial for some players in the electricity value chain but will require investment and planning, particularly for the grid
8	Sector coupling will transform the demand profile by increasing and shifting the intraday and seasonal peaks. The scale of this challenge will depend on the volume of demand-side flexibility in the system.
9	An increase in the use of green hydrogen will raise the question of production location and transport, with repercussions for both the power and gas network.

Legend

 Existing problem

 New problem caused by sector coupling

Structure

This report is presented in three parts:

Part 1 outlines what we think is a realistic pathway for sector coupling out to 2050, in what we call the 'Northern European archetype' (see box).

Part 2 analyzes the significant implications for the power system itself, assuming that our pathway is broadly met.

Part 3 highlights how policy makers and regulators could address some of the biggest challenges posed by sector coupling and its impact on the power system.

What is the Northern European archetype?

The Northern archetype is a country similar to the U.K. or Germany – ie, a market with a growing share of wind and solar in the electricity generation mix but without access to substantial flexibility resources such as hydro. It has considerable heating demand, which relies on fossil fuels (predominantly natural gas) and it has some industrial activity. Most of this report is focused on the Northern archetype, but where there are notable differences, we contrast it with a quintessential Southern European country such as Spain or Italy (the ‘Southern European archetype’).

Part 1

Sector coupling pathway

Contents

Section 1	Overview
Section 2	Sector coupling pathway – in brief
Section 3	Impact on electricity demand and supply
Section 4	Pathway method and assumptions

[Click on the link to jump to that section](#)



Section 1. Overview

This first part of the report outlines our ‘stylized pathway’ for sector coupling, its impacts on electricity supply and demand, and some of the main assumptions behind the pathway.

We think our ‘stylized pathway’ is a believable trajectory for sector coupling in Europe to 2050. It is not strictly speaking BNEF’s forecast – this would require us to predict future policy. Instead, the pathway is presented as a starting point to assess the potential impact of sector coupling on the power sector, setting up the further discussion on market design and policy implications.

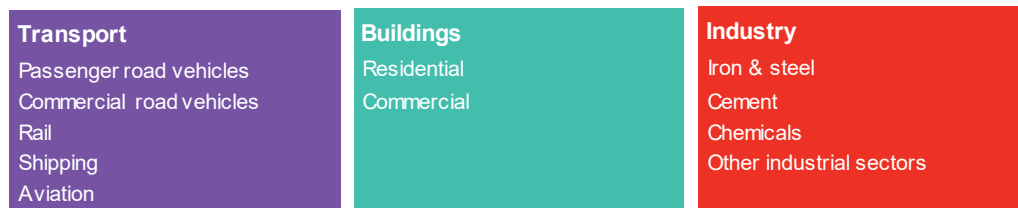
The stylized pathway covers the transport, buildings and industry sectors as seen in Figure 8, including both direct and indirect electrification. The pathway, and this report, focus in particular on the ‘sector coupling technologies’ (those in the blue box), and what we call the ‘Northern European archetype’ rather than a specific country, in order to make the findings of this report useful for a wider audience.

The Northern European archetype has a power mix with a substantial share of variable renewables in future, but does not benefit from large, flexible hydro resources (thereby excluding the Nordic countries, for example.) It has substantial heating demand, for which it relies on fossil fuels (notably gas); and it has some industrial activity. Countries that fit this archetype include Germany, the U.K. and the Netherlands.

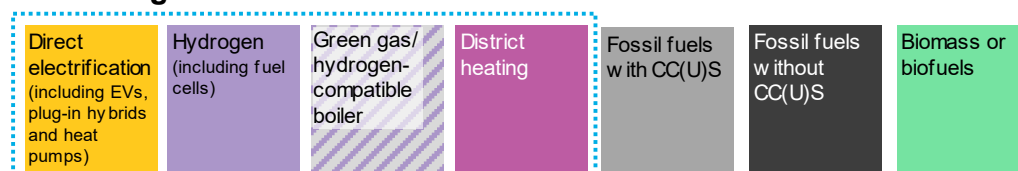
For some sectors, we highlight particular differences in a ‘quintessential’ ‘Southern European archetype’ in terms of seasonal patterns and challenges. This archetype has a similar power mix but has less heating demand and more need for cooling. Some examples are Spain, Italy and Portugal.

Figure 8: Sector coupling pathway coverage

Sectors



Technologies



Sector coupling technologies

Source: BloombergNEF. Note: Aviation includes domestic flights and those originating from the country. Shipping includes domestic navigation and ships refuelling in the country’s waters.

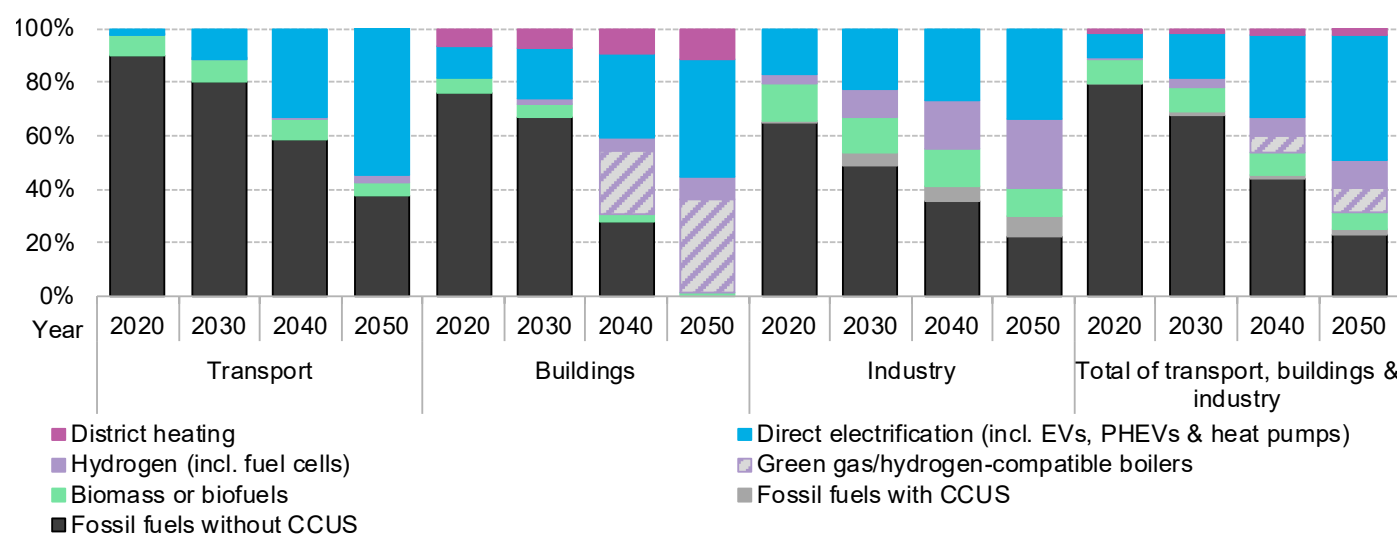
Section 2. Sector coupling pathway in brief

This section briefly describes the sector coupling pathway, a trajectory for (direct and indirect) electrification of transport, buildings and industry in Europe to 2050. For a more detailed view into the pathway for each of these sectors, please see Appendix A.

According to our pathway, the fuels used for energy in the transport, buildings and industry sectors are set to be transformed over the next 30 years (Figure 9).

The **transport sector** has already begun electrification, driven by government support and the growing cost competitiveness of EVs. In our pathway, direct electrification captures 56% of transport energy consumption by 2050, largely thanks to road-going EVs. Direct electrification accounts for 85% of energy consumed by passenger and light & urban commercial vehicles in 2050, according to the pathway. However, as a whole the transport sector's progress is hindered by the more challenging sub-sectors: the heavy & long-haul commercial segments as well as aviation and shipping, which only take small steps toward electrification.

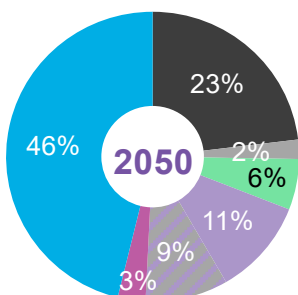
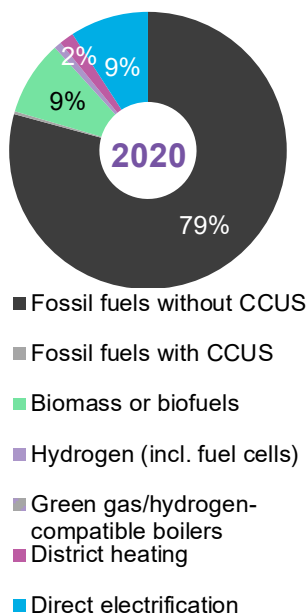
Figure 9: Breakdown of energy consumption by fuel source across transport, buildings and industry in the Northern European archetype



Source: BloombergNEF. Note: Shares are weighted by each sector's and subsector's energy consumption in the Northern European archetype (Eurostat).

The **buildings sector** initiates coupling later than transport but by 2050, it will consume at least as much energy from direct and indirect electrification – 56% – thanks to the mix of policy and economics. But this share for buildings could be significantly bigger: we have assumed that much of the remaining energy demand is met by the gas grid, supplying boilers with green gas. We are agnostic as to the precise mix of this decarbonized network – it could be predominantly biomethane, a hydrogen-blend or a pure hydrogen network (with some mix of 'blue' and 'green' hydrogen). If some of this were 'green' hydrogen produced from electricity, then this would add to the proportion of 'sector coupled' demand. However, this choice will have to be made by

Figure 10: Energy consumption by fuel source in the Northern European archetype



Source: BloombergNEF.

Note: Direct electrification includes EVs, PHEVs and heat pumps.

government. Since boilers must be designed for a specific blend of hydrogen, we assume that all new boilers sold, after a certain point, must be compatible with the government-planned energy mix for the decarbonized gas grid. Including district heating, the buildings sector is largely low-carbon by 2050, according to the pathway.

Industry sees the largest increase in the use of hydrogen – as electrolysis using renewables reaches cost parity with fossil fuels for some products and processes over 2030-50, based on BNEF's carbon-price outlook. In the first half of the period, sectors requiring very high temperatures (eg, iron & steel, and chemicals) make limited use of direct electrification due to the lack of industrial-scale electric furnaces. The reliance on fossil fuels without CCUS by 2050 varies significantly across industry – iron & steel, cement and chemicals have an average share of 40% while the remaining sectors (eg, pulp & paper, and food & drink) fall to 8%. Because these other sectors account for more than half of industrial energy consumption, industry as a whole sources 60% of its energy use from power by 2050.

Summary for transport, buildings and industry

The last part of Figure 9 shows the total energy mix **across the three coupled sectors**. Nearly half of their energy use in 2050 is fueled by direct electrification – up from around a tenth today – while indirect electrification via green hydrogen expands its share by 10 percentage points to 11% by 2050. Transport makes the biggest contribution to this growth because it begins with the smallest share in 2020 (2%). It is also responsible for nearly half of energy consumption across the three sectors, with buildings and industry accounting for around a quarter each. The vast majority of the progress in transport is due to direct electrification (EVs), but the improving economics for hydrogen production mean that the split between direct and indirect electrification in the industry sector is more even. The use of bioenergy resources is restricted to certain key sectors (eg, aviation and plastics) due to concerns over sustainability and feedstock supply.

As a result, the **energy mix** of the Northern European archetype has transformed by 2050: unabated fossil fuels supply slightly more than a fifth of these three sectors' energy demand – down from 79% in 2020 – while direct and indirect electrification together account for 50-60% by the end of the period, including district heating fueled by power, compared with a tenth in 2020 (Figure 10). The ultimate share of electrification depends on how much of the hydrogen is produced using electrolysis versus other technologies such as steam methane reforming. As explained below, our detailed analysis of the impact of the pathway on the power system assumes electrolysis accounts for 16% of hydrogen production by 2050, in line with the U.K. Committee on Climate Change. This equates to a total of 50% for direct and indirect electrification.

The changing energy mix for the coupled sectors as well as the continued decarbonization of the electricity system cuts **greenhouse-gas emissions** across transport, buildings and industry by 60% between 2020 and 2050 (Figure 11). This equates to a 71% reduction below 1990 levels. This estimate assumes that, during that period, all the green gas/hydrogen-compatible boilers are fueled by green gas and hydrogen, in which case buildings is the best performing sector. However, if the green gas/hydrogen-compatible boilers are all fueled by natural gas, electrification would yield emission savings across the coupled sectors of some 45% over 2020-50. In industry, the increasing cost parity of green hydrogen with fossil fuels and other technological advancements mean that the greatest decline in emissions occurs in the 2040s. But overall the slow progress means that industry sees the smallest emission reduction out of the coupled sectors.

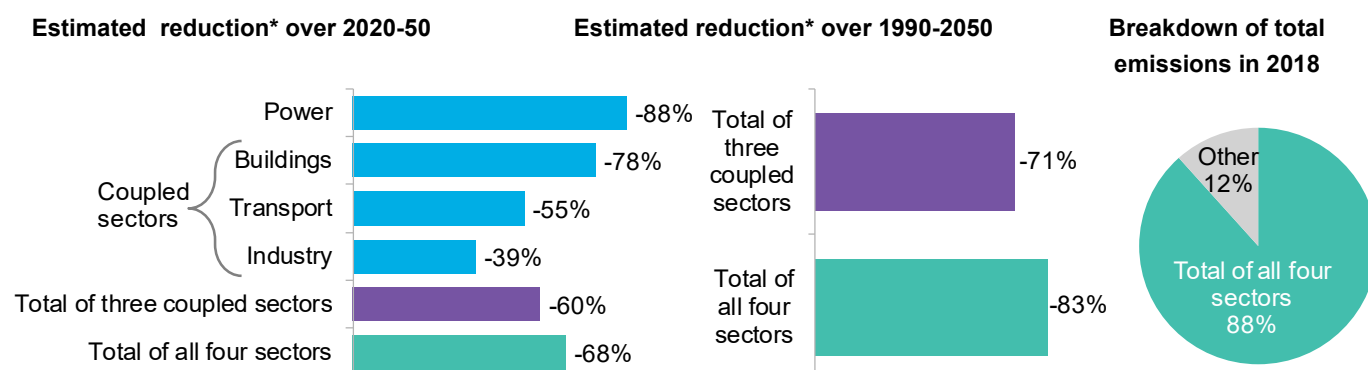
Summary including power sector

The power system has already made great strides toward decarbonization – a trend we expect to continue. Sector coupling adds slightly to power sector emissions, but the electricity system still cuts greenhouse-gas output by 88% over 2020-50 – even with sector coupling.

As a result, the pathway produces a 68% decline in emissions over 2020-50 across power, transport, buildings and industry. Together, these four sectors accounted for nearly 90% of greenhouse-gas output in 2018. Sector coupling would therefore put a country like the U.K. and Germany well on the way toward its climate goals: indeed, by 2030, the four sectors could cut emissions by 63% below 1990 levels compared with the EU legislated target of 40%. By 2050, greenhouse-gas output could be 83% lower than 1990 levels.

However, additional action would be required to eliminate emissions completely from these sectors and meet the EU target of becoming the first climate-neutral continent by 2050. Negative emission technologies and changes to land use, for example, were excluded from our pathway as they are not part of sector coupling, but would likely be needed to achieve net zero. In addition, as discussed in the sections below, sector coupling will not be possible without considerable effort and investment by policy makers, regulators and business.

Figure 11: Greenhouse-gas emissions in the Northern European archetype



Source: BloombergNEF based on conversion factors from the U.K. government. U.K. and German government for 2018 breakdown. Note: * Emission-reduction estimates assume that all compatible boilers in buildings are fueled by green gas or hydrogen.

Section 3. Impact on electricity demand and supply

Overall, with sector coupling, power demand for transport, buildings and industry in the Northern European archetype increases by 65% over 2018-50 (Figure 12). (See Appendix A.3 for assumptions.) This compares with a 15% decrease in demand in the base case without sector coupling, driven by improved energy efficiency, relatively modest economic expansion and reduced energy-intensive industrial production. In other words, sector coupling means nearly twice as much power demand in the Northern archetype by 2050.

3.1. Power demand

Figure 12: Power demand in the Northern European archetype

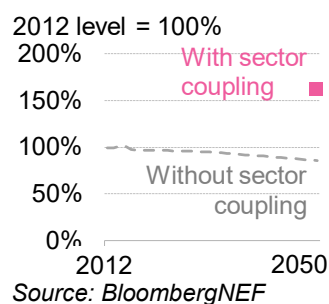
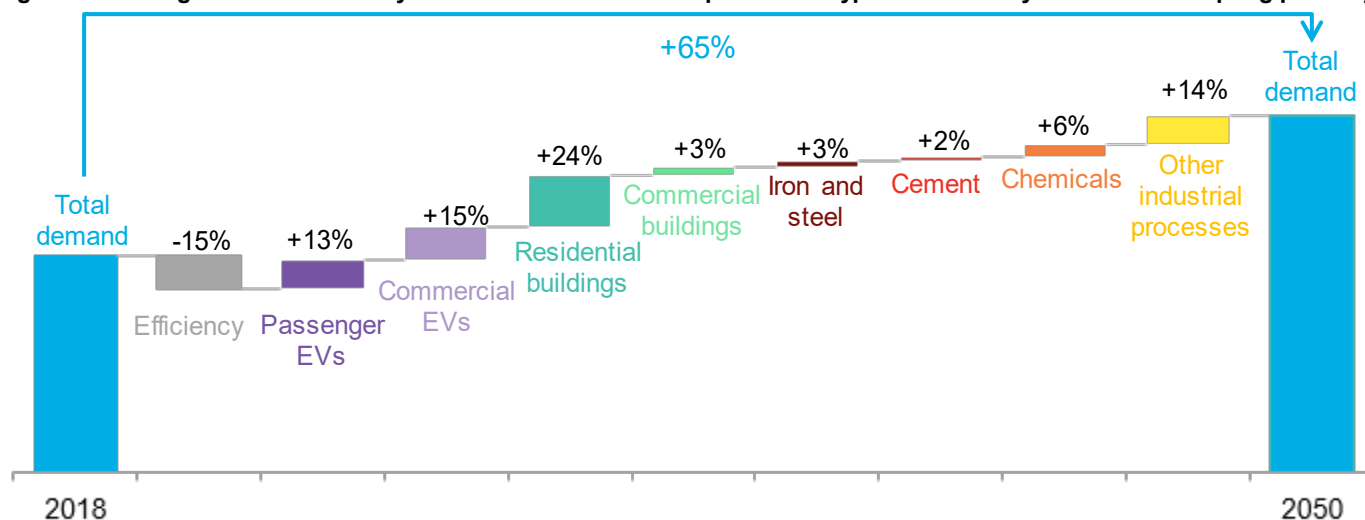


Figure 12 shows the change in power demand in the Northern European archetype over 2018-50 for two scenarios:

- The **scenario without sector coupling** forecasts power demand without any additional consumption from the transport, buildings or industry sectors relative to 2018 levels. (Note that this differs from the demand projection in BloombergNEF's *New Energy Outlook 2019*, which assumes increasing electricity consumption for transport due to rising EV uptake.)
- The **scenario with sector coupling** incorporates the increasing use of direct and indirect electrification for transport, buildings and industry, based on the sector coupling pathway outlined in Section 2. and described in more detail in Appendix A.

Power demand in the sector coupling scenario is nearly double that of the scenario without coupling in 2050. In other words, about half of power demand in 2050 comes from our coupled sectors. This huge increase is largely driven by more direct and indirect electrification of the transport and buildings sectors (Figure 13).

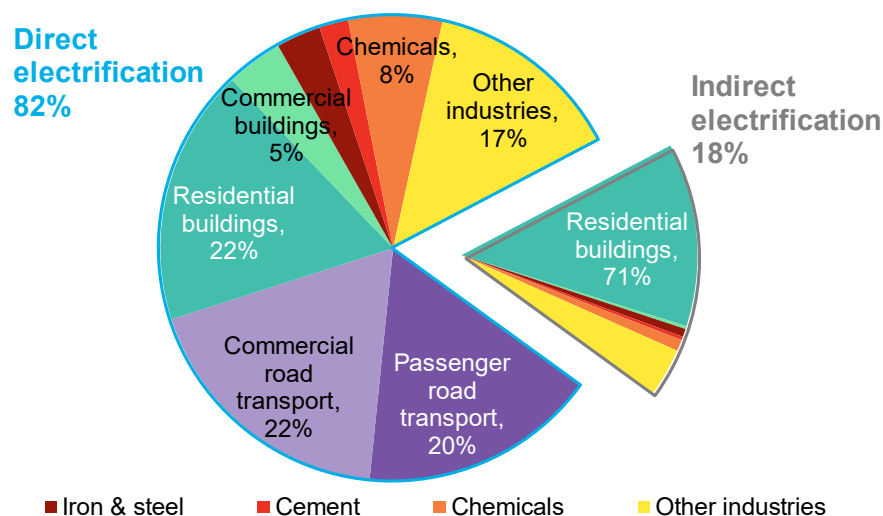
Figure 13: Change in total electricity demand in Northern European archetype based on stylized sector coupling pathway



Source: BloombergNEF. Note: The waterfall chart includes direct and indirect electrification. Excludes the minor volume of power demand from aviation, shipping and district heating.

Residential buildings consume substantially more electricity as they switch from sourcing more than 80% of energy from fossil fuels, to 48% from direct electrification alone. Residential buildings also have the largest share of indirect electrification (hydrogen or gas from electrolysis) by 2050 driven by policy support and improving economics. This means the buildings sector accounts for nearly three-quarters of indirect power demand by 2050. Increasing cost competitiveness for hydrogen use in iron & steel production means that indirect electrification accounts for a larger share of energy consumption in this sector compared with chemicals and cement.

Figure 14: Breakdown of power demand from sector coupling, 2050



Source: BloombergNEF. Note: "Indirect" electricity demand refers to power-to-X / hydrogen electrolysis to meet energy demand. Percentages for each subsector relate to their share of direct and indirect electrification demand. Assumes residential and commercial buildings still on the gas grid are fueled by hydrogen, of which 16% is produced by electrolysis.

Exactly when and where this increased power demand will manifest itself has major implications for the power system. This topic is discussed in more depth in later sections, in particular Section 7 and Section 8.

A note on hydrogen production and power demand

As mentioned earlier, a substantial share of building energy demand is met by a decarbonized gas grid by 2050 – likely to be some mix of biomethane, and hydrogen either from steam methane reforming (SMR) or electrolysis. Of these, only hydrogen (or synthetic gas) from electrolysis can be considered indirect sector coupling, since the other fuels are not produced from power. For the purposes of deriving a power demand figure, our analysis assumes that most hydrogen production uses steam methane reforming (SMR) technology (potentially with CCUS), with a limited contribution (16%) from electrolysis. This is the same assumption used by the U.K. Committee on Climate Change.² Power demand could be much higher if this share were to rise.

Impact of data centers and the ICT sector

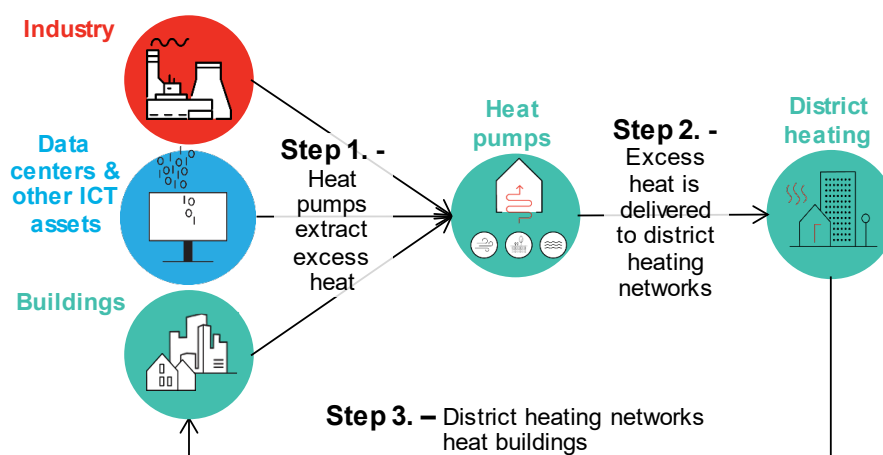
These estimates assume that at a country level, energy savings offset the anticipated increase in electricity demand from data centers and connected devices. Such savings will come from more

2 Committee on Climate Change, Net Zero – Technical Report, May 2019.

efficient processors, switching to large-scale facilities and the use of machine learning, for example. Data centers, especially hyper-scale facilities, have a relatively stable demand profile, lacking particularly high seasonal or intraday peaks. However, with the focus on building data centers and other ICT networks in clusters (Section 8.1), the impact on the power system in some locations will be large. Data centers also offer several opportunities to mitigate some of the problems for the power sector caused or exacerbated by sector coupling. These are highlighted throughout the report.

There are also potential synergies that sector coupling may unlock. For example, heat pumps could be used to cool data centers, commercial buildings such as supermarkets, or industrial processes, and the excess heat could be delivered to a district heating network and used for building heating (Figure 15).

Figure 15: Illustration of sector coupling synergy – how to reduce required capacity build



Source: BloombergNEF

3.2. Capacity build and power generation

Some 75% more generating capacity needs to be built in the Northern European archetype over 2018-50 in order to meet additional power demand under the sector coupling pathway. This estimate draws from BNEF's *New Energy Outlook 2019* – our annual long-term analysis of the future of energy, which is based on a least-cost approach.³

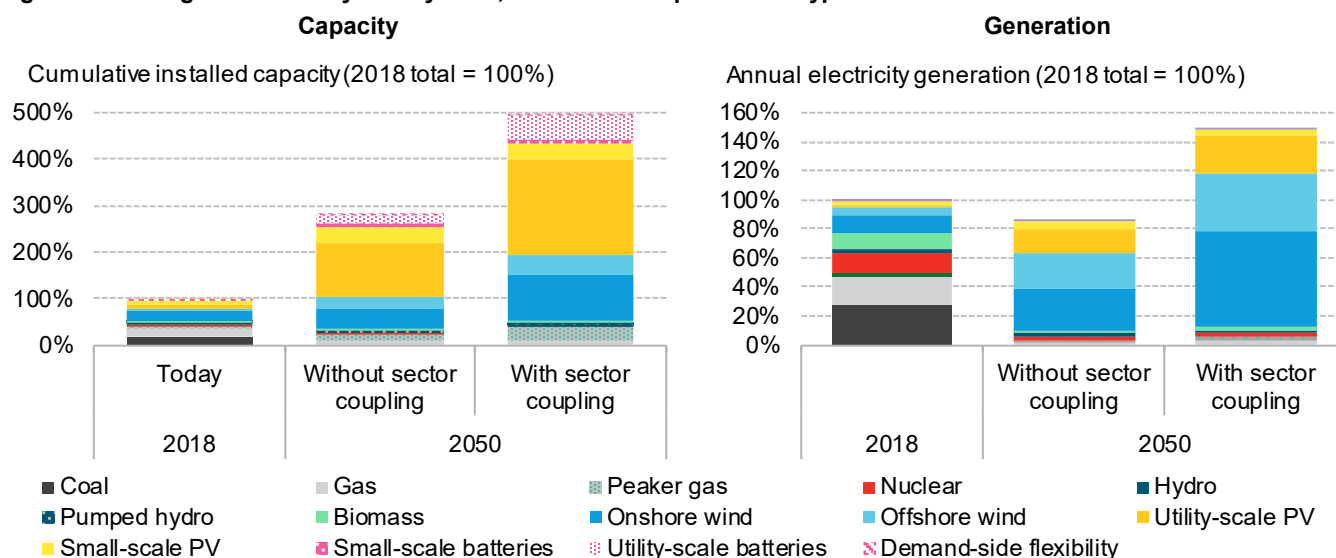
With or without sector coupling, increasingly favorable economics mean that onshore wind and utility-scale PV account for the biggest growth in generating capacity. But with sector coupling, roughly double the amount of both wind and solar build are needed. In addition, flexible resources (especially utility-scale battery storage and peaker gas plants) expand under the sector coupling scenario to balance the increased variable generation. By 2050, in both scenarios, wind and solar account for three-quarters of the capacity mix. These additions mean that total capacity with sector coupling grows nearly 400% compared with an increase of some 180% without sector coupling.

³ Read more about the *New Energy Outlook 2019* on the [BNEF website](#) and clients can access the underlying data on the [client website](#) or [Terminal](#).

The investment needed in new generating capacity by 2050 is about 64% higher than in the scenario without sector coupling. Most of the additional investment is spent on zero-carbon power plants and a further tenth on battery storage.

This estimate assumes that generating capacity is built in the required volume to meet demand. However, sector coupling offers several opportunities to reduce the potential peak demand and therefore the required build. These are discussed in Section 7.

Figure 16: Change in electricity mix by 2050, Northern European archetype



Source: BloombergNEF. Note: Includes direct electricity demand only

By 2050, wind and solar are expected to supply the vast majority of electricity demand in the Northern European archetype, with or without sector coupling. This is driven by rapid cost reductions in renewable energy technologies, and shifting fundamentals. The changing economics of electricity generation mean that zero-carbon power supplies 96% of all output by 2050, in both scenarios (Figure 16).

Wind meets the majority of electricity demand in both scenarios by 2050: with sector coupling, this technology has a slightly larger share of power generation in 2050 (at 70%) in the Northern European archetype. Meanwhile solar fulfils 24% of annual power needs without sector coupling and 21% with coupling by 2050.

Such a sizeable share of generation from variable renewables is made possible by the falling costs of energy storage. Lithium-ion batteries are getting cheaper as manufacturing scales up. As a result, storing variable generation from wind and solar (both co-located with renewables and stand-alone systems) is expected to become cost-competitive with new coal and gas. The combination of cheap renewables and storage means that the Northern European archetype's electricity mix almost fully decarbonizes on a least-cost basis by 2050.

Section 4. Pathway method and assumptions

The sector coupling pathway has as its bedrock BNEF's economic analysis of the individual technologies and sectors. However, to develop a 'plausible pathway', it was necessary to add in a view of countries' future policy ambitions, either to overcome barriers to adoption or to accelerate already economically-favorable transitions. The pathway was further shaped by a range of factors, including consumer-uptake behavior and asset lifetimes.

This section presents a brief overview of the method and assumptions behind the pathway. For a fuller description, see Appendix B.

4.1. Economics

First, we examine the economics of each of the technologies and sectors based on BNEF analysis, where possible, and reputable third-party sources. For example, we consider when heat pumps may reach cost parity with gas boilers for home heating, or when clean hydrogen may become economic for steel production. Technical feasibility and non-economic challenges are also considered. Table 2 outlines the main economic assumptions behind the pathway. See the Appendix for more detail. These represent BloombergNEF's best assessment of how these sectors will develop over the next 30 years, based on our in-depth analysis of the economic, technology, policy and investment trends. Overall, the economics for electrifying light-duty road transport are better, sooner, than for any of the other sector coupling vectors, direct or indirect.

Table 2: Overview of economic assumptions behind sector coupling pathway

Sector	Assumptions
Transport	<ul style="list-style-type: none"> • Passenger battery EVs (BEVs) become competitive with ICE vehicles on upfront cost basis in Europe over 2022-26, the exact timing depending on size. • Light-duty commercial BEVs and plug-in hybrid EVs/range extenders (PHEV/REXs) are the cheapest option from 2020 on a total cost of ownership basis, and from 2024 for medium-duty vehicles. • Heavy-duty electric vehicles for regional and long-haul transport do not become competitive with ICE vehicles within the pathway timeframe. • Electricity remains the dominant technology for rail but is limited to short-haul journeys for shipping and aviation. <p>For our more detailed forecast of electrification in the transport sector, see the free public summary of the <i>Electric Vehicle Outlook 2019</i>. BloombergNEF clients can access the full report and underlying datasets at web terminal.</p>
Buildings	<ul style="list-style-type: none"> • Existing single-family homes that are owner-occupied switch to heat pumps based on economics (when competitive) and consumer behavior. • Air-source heat pumps are already competitive with most oil heating systems but only become cheaper than gas on a total cost of ownership basis after 2040. • Hydrogen fuel cells become competitive with air-source heat pumps (but not with gas) in the 2030s.

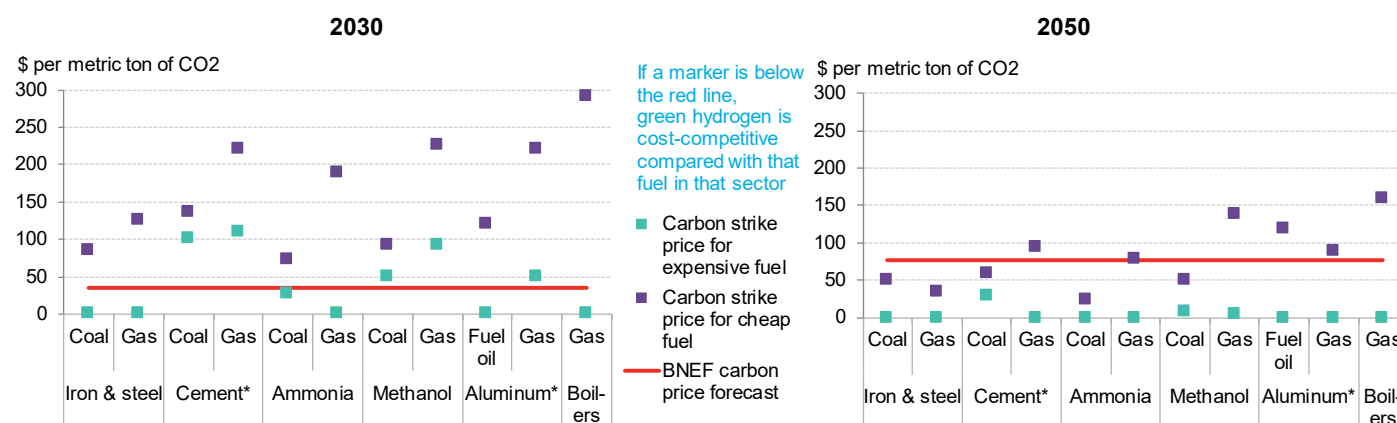
Sector	Assumptions
--------	-------------

- | | |
|-----------------|---|
| Industry | <ul style="list-style-type: none"> Based on BNEF's European carbon price forecast, green hydrogen is cost-competitive for: <ul style="list-style-type: none"> Steel and ammonia production with expensive gas or coal by 2030, and with cheap coal and gas by 2050. Cement with all fossil fuels by 2050. High-grade heat produced by coal or gas in all industry sectors by 2050. |
|-----------------|---|

Source: BloombergNEF

As an example, one of the inputs to the pathway was BloombergNEF's analysis of green hydrogen costs to 2050. Figure 17 shows the carbon price required for green hydrogen to reach cost parity with coal, gas and fuel oil (for aluminium), together with BNEF's forecast for European emission allowances in that year. If a marker is below the red line, green hydrogen is assumed to be competitive with that fuel in that sector. Clients can access our analysis of hydrogen costs on the [website](#) and [Terminal](#).

Figure 17: Carbon price required for green hydrogen to be cost-competitive with selected fuels, by industry sector



Source: BloombergNEF. Note: * For industrial heat only. Boilers are for space and water heating in buildings. The level of 'expensive' and 'cheap' fuel varies across sectors.

4.2. Policy

Next we take a view of the relevant countries' policy objectives in terms of whether they either overcome barriers to adoption (economic or otherwise) or accelerate already economically-favorable transitions. This is necessarily subjective and incorporates our carbon price forecast, which averages 26 euros per metric ton in the 2020s and increases to 76 euros in 2040. (See Appendix B.2.) We expect industrial abatement to ramp up in the 2030s, driving up the price.⁴ We assume that governments implement incentives (eg, subsidies, phase-out bans) where technologies (eg, heat pumps) have reached, or are close to reaching, cost parity with the fossil-fueled option (eg, gas boilers). Where the economics are less favorable, the pace of coupling is slower. We never assume that deeply uneconomic options are forced through by policy.

The extent of this policy intervention is based on governments' twin goals:

4 For BloombergNEF clients: 1H 2019 EU ETS Market Outlook ([web](#) | [terminal](#)).

- **To reduce greenhouse-gas emissions:** we expect the Northern European archetype to remain committed to ambitious action to promote decarbonization. For example, the U.K. legislated in June 2019 its target to reach 'net zero' by 2050 and France followed suit in September 2019. Germany's climate change bill, which came into force in December 2019, includes a plan to reach carbon neutrality also by 2050.
- **To minimize expenditure:** governments likely want to avoid the same subsidy cost burden seen to support renewable power. We therefore anticipate that they will only introduce subsidies for technologies relatively close to cost parity and may opt for a 'stick' approach (eg, phase-out bans of internal combustion engine (ICE) vehicles and gas boilers). In a similar vein, they want to avoid introducing policies that would impose a substantial cost burden on consumers or business.

The EU's stringent environmental regulations on biomass and biofuels are one reason why the pathway assumes their use is limited to the early years of the period, to sectors that have access to abundant, low-cost waste residues (eg, pulp & paper), and to certain high-priority sectors where other decarbonization options are not available. Table 3 outlines the main policy assumptions behind the sector coupling pathway and more detailed information is in Appendix A.2.

Table 3: Overview of policy assumptions behind sector coupling pathway

Sector	Northern European archetype	Southern European archetype
Transport	<ul style="list-style-type: none"> • Sales of passenger ICE vehicles are banned from 2040. • Cities meet C40 commitments regarding zero-emission public buses from 2025. 	<ul style="list-style-type: none"> • Same as for the Northern European archetype.
Buildings	<ul style="list-style-type: none"> • From 2030 no new residential or commercial buildings may connect to the gas grid or have an oil-fired boiler; and all rented single-family homes must switch to low-carbon heating. • The gas network is converted to green gas or to 100% hydrogen networks. Remaining gas homes must convert to hydrogen-compatible boilers; or to hydrogen-heat pump hybrids over 2030-50. 	<ul style="list-style-type: none"> • Same as for Northern European archetype, except it does not implement a switchover for the gas grid to hydrogen.
Industry	<ul style="list-style-type: none"> • The pathway assumes that governments introduce policies to promote decarbonization of industry (including carbon capture, use and storage – CCUS). But it is agnostic on any specific incentives or targets. • BNEF assumes government will take action to prevent carbon leakage (see box below). 	<ul style="list-style-type: none"> • Same as for the Northern European archetype, except its policy support for CCUS remains minimal.

Source: BloombergNEF

We have not incorporated the proposals included in the European Commission's Green Deal, which was published in December 2019. This high-level document proposes to increase ambition to a 50-55% reduction in emissions by 2030. Its schedule is for the EU's first climate law to be released in 1Q 2020 and to include a bloc-wide net-zero greenhouse gas emissions target for 2050.

While multiple legislative reforms would be needed in the coming years before these proposals could come into force, the Green Deal gives an indication of travel. Evidently if the target were enacted – together with measures to implement it – this would significantly accelerate sector coupling and require more urgent action by policy makers to mitigate any negative effects on the power system.

Carbon leakage

The pathway assumes government continues to protect industrial companies exposed to international competition (eg, steel and chemicals) from ambitious environmental regulation. It reflects concern that without this protection, companies would relocate to other jurisdictions with less onerous carbon regulations through the process known as 'carbon leakage'. This therefore restricts the volume of industrial decarbonization at least in the near term. Historically such vulnerable sectors have received additional free allocations of EU ETS permits (Figure 18) – a set-up due to continue at least until 2030.

The Green Deal published in December 2019 confirmed that the European Commission will put forward a border carbon adjustment mechanism. This is in line with the sector coupling pathway. Depending on how it is set up, other countries reliant on trading with the EU will be encouraged to increase their climate ambition, but they may also respond by introducing retaliatory tariffs. The tax would only include primary materials such as steel and chemicals, which leaves the door open to leakage through assembled products like mobile phones and cars. Details about the design is sparse and implementation will likely take years.

Figure 18: Industrial verified EU ETS emissions and free allocation

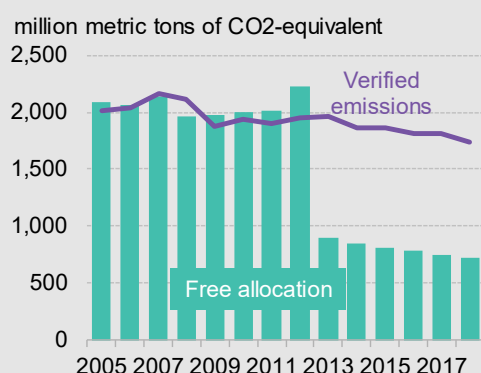
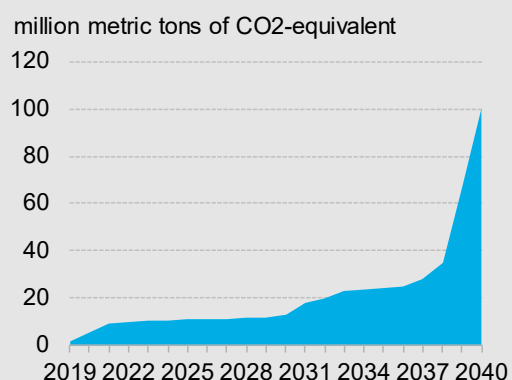


Figure 19: Cumulative industrial permanent abatement in the EU ETS



Source: BloombergNEF, EU Transaction Log.

As the European carbon price approaches 70 euros per metric ton at the end of the 2030s according to BNEF's forecast, industrial companies are expected to make sharper emission reductions (Figure 19). At this stage, the pathway assumes that governments will be willing to increase financial support to promote industrial decarbonization. (The economics will be more favorable by this stage, reducing the potential outlay from the public purse.)

4.3. Other factors

The pathway is further shaped by a range of factors:

- **Maturity and availability of technologies:** the pathway considers technologies at a range of developmental stages. The timing of market entry is based on BNEF's forecasts of cost parity (where possible) together with their technical and commercial readiness, and BNEF's experience and knowledge of energy technologies.
- **Consumer uptake behavior:** as with other consumer products, the proportion of the population that can attain and benefit from a consumer good increases as the cost of a

product falls and as public awareness of the product rises. In other cases, the pathway assumes some policy intervention. This pattern has been seen for consumer goods such as washing machines, televisions and rooftop PV, and we apply similar logic in our pathway for vehicles and heating appliances

- **Pressure from international competition:** commodities such as steel, ammonia and ethylene are traded globally and subject to significant cost pressure. We have therefore taken into account that there is a limit on how much additional cost burden these sectors would be able to assume for decarbonization, without the risk of carbon leakage.
- **Asset lifetimes and replacement rates:** new build accounts for only a small share of the building stock (less than 1% in the U.K.), domestic heating units have 20-year lifetimes and assets in industrial sectors such as a steel plants are especially long (eg, 50 years). This translates into a long turn-over cycle for some sectors, even after a decarbonization solution becomes competitive.
- **Uptake limitations:** our projections take account of technological or economic constraints on uptake, for example, the current limited volume of private EV charging points.

Part 2

Impact of sector coupling on the power system

Contents

Section 5	Overview
Section 6	Power generation
Section 7	Flexibility and demand
Section 8	Grid

[Click on the link to jump to that section](#)



Section 5. Overview

As outlined in Part 1, the sector coupling pathway nearly doubles electricity demand by 2050, compared to a case with no coupling. As well as requiring significantly more generating capacity to be added, sector coupling will have significant repercussions for the power system. This part focuses on three main areas: the implications for investment in generation (Section 6), flexibility and demand (Section 7), and the electricity and gas networks (Section 8).

Table 4 outlines the principal impact of sector coupling on the key power system problems.

Table 4: Impact of sector coupling on power system problems and implications

Key problem	Impact of sector coupling	Implications		
Generation				
7	Total electricity demand	Sector coupling substantially increases total demand in the Northern European archetype. But it does not resolve the 'missing money problem' (see Section 6.1) because realized prices will only be higher in the unlikely scenario where no additional capacity is built.	Policy makers will need to resolve the missing money problem, without jeopardizing the decarbonization of the power sector.	
1	Investment signals		Generators will seek other opportunities to increase and stabilize revenue. Examples include power purchase agreements and capacity mechanisms.	
Flexibility				
2	Need for more flexibility	The growing share of variable generation in the mix increases need for short- and long-term flexibility. This is a challenge because not all sources of flexibility are adequately valued and remunerated Sector coupling will also transform the demand profile by creating steeper peaks during the day and more seasonal variation due to heating demand.	The scale of this challenge will depend on the volume of demand-side flexibility in the system. There are very few commercially ready technologies that can provide long-run power system flexibility (without carbon emissions or other issues for sustainability) to mitigate the increased seasonal variation.	
3	Value of flexibility			
8	Demand profiles			
Grid				
7	Power flows	Rising power demand means heavier flows on the electricity grid, most likely leading to more congestion. Growth will be bumpy and non-uniform, with new demand characteristics. Capacity expansion may be needed.	In the short-to-medium term, system and network operators will have to spend more on congestion management measures. In the long term, grid investment will be required, as well as a flexible regulatory structure for network operators, more data visibility, collaboration among industry players and initiatives to boost public acceptance. Distribution utilities will come under further pressure to take on more system operator functions more quickly and develop new systems to manage the dynamic grid. Switching to a 100%-hydrogen grid (as envisaged for some regions) requires the gas network to be upgraded or replaced, together with components and appliances. Some countries may be able to reduce spending but the cost and required disruption will still be high.	
5	Geographic challenges			Grid extension may be needed where energy resources and generating capacity are far from demand centers.
8	Peak demand			Network constraints may be particularly acute at the distribution level in certain local areas, due to clusters of EVs, data centers and other loads.
4	DERs on the grid			The addition of more distributed energy resources due to sector coupling will add to the challenges for distribution utilities.
9	Hydrogen and gas			As hydrogen production grows, more of it will need to be transported via the gas grid. Green hydrogen producers need to take account of the location of the gas and electricity networks.

Source: BloombergNEF

Legend



Existing problem



New problem caused by sector coupling

Section 6. Power generation

As outlined earlier, a high-renewables power system is very likely to face a ‘missing money’ problem. Sector coupling adds substantially to power demand, but we do not expect this to remedy the missing money problem. Additional policies (or new market designs) will therefore be needed to provide revenue certainty for renewable generators, to drive the investment needed. If – as some EU countries have done – policy makers introduce a capacity mechanism, we anticipate that they will need to implement alternative measures to ensure that the required low-carbon capacity is built. If not, this could blunt the decarbonization benefits of sector coupling by favoring the construction of carbon-emitting power plants.

Table 5 outlines the most important potential problems for electricity generators.

Table 5: Key power system problems for generation

1	The power sector may fail to deliver a clean and reliable supply of electricity because the wholesale market does not offer credible signals for investment in renewable and dispatchable capacity. This is the ‘missing money’ problem.
6	A power market needs to encourage technological innovation and ensure future-proofing.
7	Sector coupling will substantially increase total electricity demand over the next 30 years even in markets where demand would otherwise flatten out or decline. This may be beneficial for some players in the electricity value chain but will require investment and planning, particularly for the grid
Legend x Existing problem x New problem caused by sector coupling	

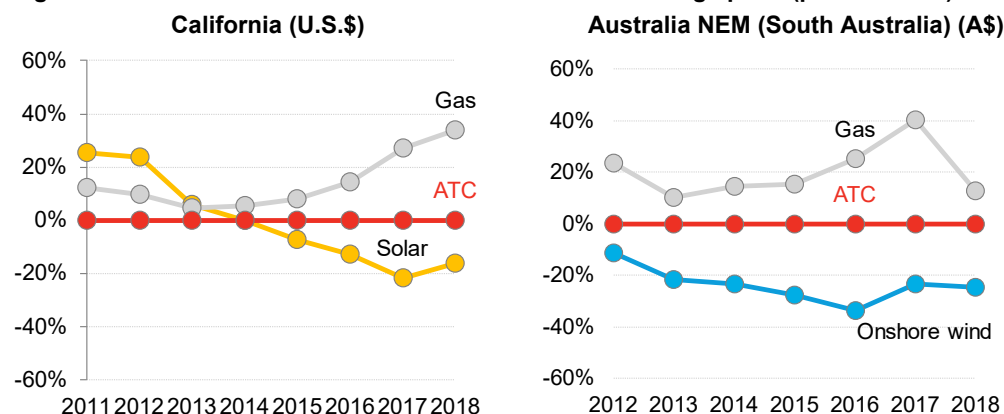
6.1. Investment signals and missing money

A successful power market provides clear and accurate signals to investors. However, generators in markets with a large share of wind and solar may face a ‘missing money’ problem whereby they will not be able to secure enough revenue on the wholesale power market to meet their target returns for investment in new capacity. This is because realized – or production-weighted – electricity prices for wind and solar plants are expected to decline due to the resulting proliferation of low marginal-cost renewables generation. This effect can already be seen in some markets with a high share of wind and solar power such as California and Australia (Figure 20).

This missing money problem implies that investors will need to rely on out-of-market contracts to support investment decisions in generation in future. At present, most operational renewables plants receive a subsidy payment, or have a long-term power-purchase agreement (PPA) that shields them from a decrease in wholesale electricity prices. However, governments are expecting to move away from subsidies as wind and solar technology costs decrease further,

increasing such plants' exposure to wholesale prices. Some 6.4GW of subsidy-free⁵ PV projects are due to come online in Europe by end-2020, according to BloombergNEF analysis.⁶ Three-quarters of the pipeline of subsidy-free solar projects are in Spain, Italy and Portugal where capacity factors are higher than in the U.K. and Germany, which together account for 10%.

Figure 20: Premium/discount on the around-the-clock average price (price scalars)



Source: CAISO, Australian Energy Market Operator, BloombergNEF: *Homage to Wholesale Power Prices* ([web](#) | [terminal](#)) and *2H 2018 Australia Power Market Outlook* ([web](#) | [terminal](#)).

As a result, renewable generators relying only on the wholesale power market may not earn enough to cover costs and make a return on equity. For example, by 2040, this shortfall could reach 42% for wind and solar plants in the U.K. according to the *2H 2019 U.K. Power Market Outlook*, available to BloombergNEF clients ([web](#) | [terminal](#)). (Figure 22).

Figure 21: Realized power price forecast, U.K.

Based on 2H 2019 U.K. Power Market Outlook

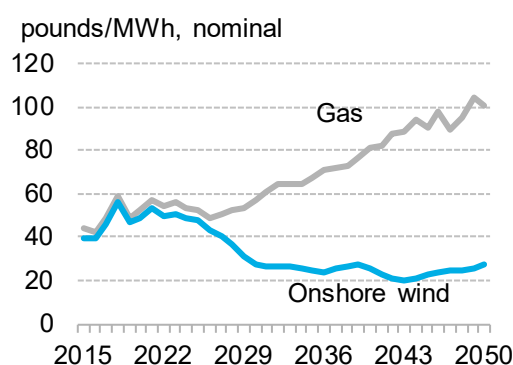
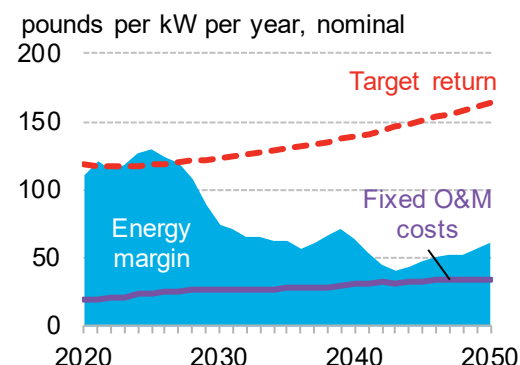


Figure 22: Energy margins and target returns for onshore wind, U.K.



Source: BloombergNEF, *2H 2019 U.K. Power Market Outlook*, available to BloombergNEF clients ([web](#) | [terminal](#)). Note: 'Energy margin' = power market revenue minus operational costs directly related to generating that energy

This is based on a least-cost scenario where wind and solar account for 80% of electricity generation in the U.K. by 2040, and excludes sector coupling other than EVs. Even projects with

⁵ BloombergNEF defines a 'subsidy-free' project to be one that does not receive government payments such as feed-in tariffs or a fixed tariff awarded by auction.

⁶ BloombergNEF clients can read the complete analysis in: *Europe's Subsidy-Free PV Market Takes Off* ([web](#) | [terminal](#))

PPAs will be affected by the declining realized prices on the wholesale market because offtakers will be less willing to pay a tariff much higher than the prevailing, low wholesale power prices.

Fossil-fueled plants will not escape unscathed: the influx of wind and solar generation will reduce the utilization, and thus capacity factors, of fossil fuel plants (Figure 23). As a result, new combined-cycle gas turbine (CCGT) plants in Germany face a shortfall averaging 154 euros/kW a year over 2022-42, in order to make a return. This estimate is based on the *2019 Germany Power Market Outlook* ([web](#) | [terminal](#)), which only includes sector coupling for transport, and expects wind and solar to comprise 74% of electricity generation by 2042.

Figure 23: Capacity factors for fossil plants, Germany

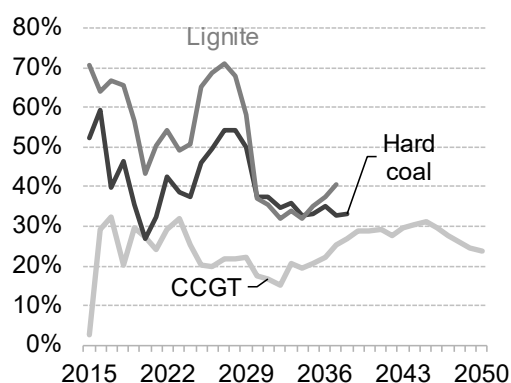
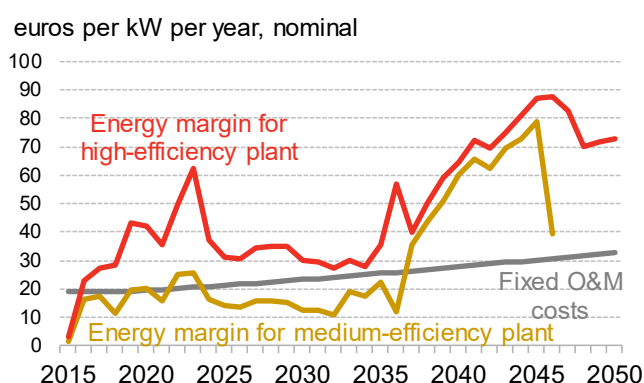


Figure 24: Energy margins and target returns for CCGTs, Germany



Source: BloombergNEF, 2019 Germany Power Market Outlook (available to clients at: [web](#) | [terminal](#)). Note: 'Energy margin' = power market revenue minus operational costs related to generating that energy.

6.2. Impact of sector coupling

Economic theory suggests that a rise in electricity demand due to sector coupling would raise realized power prices – all else being equal. However, our view is that sector coupling does not solve the missing money problem in a high-renewables power system. To gauge the impact of sector coupling on realized power prices, we raised the electricity demand forecast from the *2H 2019 U.K. Power Market Outlook* ([web](#) | [terminal](#)) by 10% and 20% over 2020-50. The 10% higher demand increases realized PV prices by 25% over 2020-50, with a 47% price increase for a 20% rise in demand (Figure 25). The boost for onshore wind revenue is even greater, averaging 41% and 72% for a 10% and 20% rise in power demand.

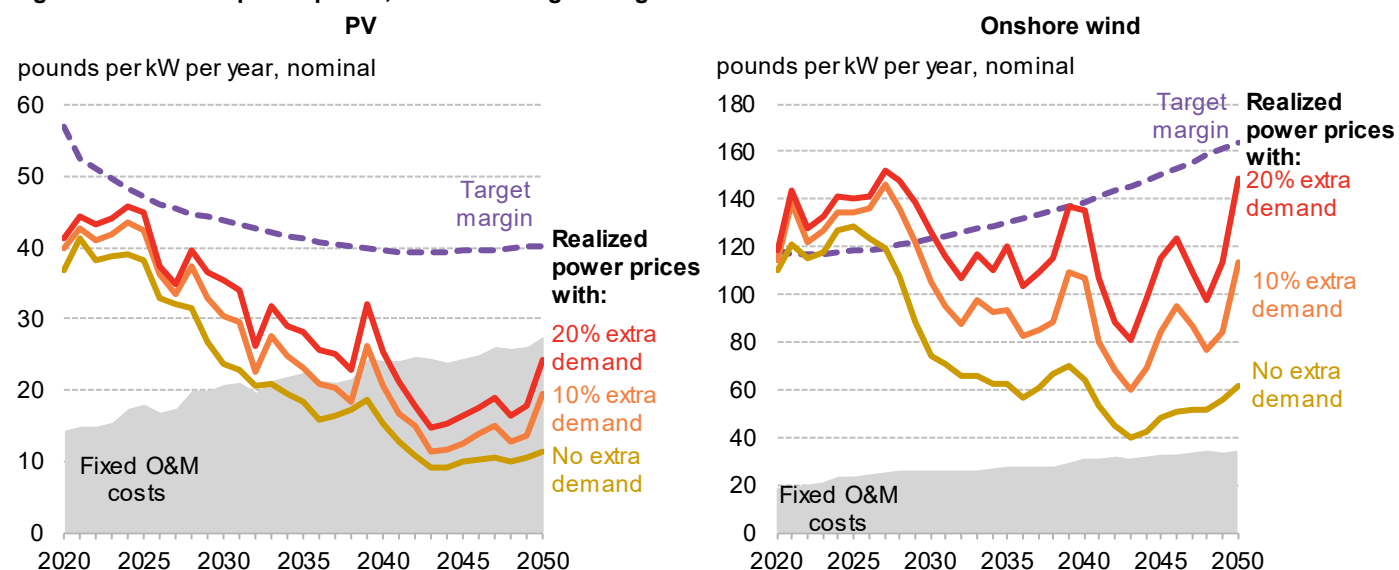
However, this additional demand would not be enough to resolve the missing money problem: the higher realized prices are not sufficiently high for generators to meet their target margins and, in the case of PV, cover their costs for the second half of the period. Therefore, the increase in electricity demand would have to be substantially more than 20% for much of the period. Furthermore, even these gains are based on an unlikely scenario where no additional generation capacity is built to meet the demand increase.

Under the sector coupling scenario, renewables technologies account for more than 90% of electricity generation by 2050. In reality, any successful power market design that achieves such high penetration of renewable power – sector coupling or not – will need to have solved the missing money problem through some other means, outside of the wholesale power market. This could be through continuing auction programs that award long-term contracts for renewable power, for example, or by obligating energy suppliers to commit to renewable power contracts, eg

through a renewable portfolio standard or emissions standard. In our modelling, the addition of power demand through sector coupling does little to change this.

Note that in practice the increase in total demand is only part of the picture. Sector coupling will change the shape of demand profiles too, and it also creates opportunities for flexible resources such as industrial demand response and dynamic EV charging. These issues are explored in Section 7.

Figure 25: Realized power prices, costs and target margins in the U.K.



Source: BloombergNEF. Note: The realized power price with 'No extra demand' is the same as in BloombergNEF, 2H 2019 U.K. Power Market Outlook, available to BloombergNEF clients ([web](#) | [terminal](#)).

Sector coupling also does little to resolve the missing money problem for gas-fired generation: capacity factors for CCGTs in the Northern European archetype are on average one percentage point higher than in the base case without sector coupling.

6.3. The risk of 'dirty' sector coupling

Several European countries have sought to ensure resource adequacy by implementing capacity mechanisms. If the missing money problem for renewables is not resolved through long-term contracts then, in markets that have a capacity mechanism, rising demand from sector coupling might in fact stimulate build of fossil-fired capacity instead. As well as keeping online large volumes of capacity, capacity mechanisms also keep online dirtier or less efficient power plants: low-capex peakers with higher emissions and lower efficiencies have tended to win support as the initial investment is lower.

The EU [internal electricity market regulation](#) passed in 2018 seeks to avoid this outcome by requiring EU countries to meet certain conditions before they can introduce a capacity mechanism, including emission thresholds. However, most such programs do not allow renewables to participate, or they pose other barriers, such as very low de-rating factors.⁷ In essence, if the Northern archetype were to opt for a capacity mechanism to remedy the missing

⁷ A de-rating factor is percentage of nameplate capacity of the fleet that the grid operator expects to have online at any given moment.

money problem, it could slow the transition towards high-renewables power systems and blunt the climate benefits of sector coupling.

For these reasons, we expect policy makers to put in place alternative measures to ensure that the required, low-carbon generating capacity is built.⁸ See Section 14 for a detailed discussion.

8 For a detailed analysis, BloombergNEF clients may go to: *Power Market Design: Investment Signals & Missing Money II* ([web](#) | [terminal](#))



Section 7. Flexibility and demand

Sector coupling brings significantly higher power demand, which is expected to be met by low-cost wind and solar. More battery storage and gas-fired generation is needed to balance the greater share of variable generation. In addition, the intraday and seasonal load profiles are higher and steeper, affecting how short- and long-run flexible resources are used.

The scale of the challenge depends principally on the uptake of the new demand-side flexibility created by sector coupling. More dynamic demand means less investment in flexible capacity, lower system costs and lower power emissions. Indeed, sector coupling increases the greenhouse-gas output for the electricity sector itself; but it means substantially lower economy-wide emissions as transport, buildings and industry switch away from fossil fuels.

The relevant challenges potentially exacerbated or caused by sector coupling are detailed in Table 6.

Table 6: Key power system problems for flexibility

2	The growing share of variable generation in the mix makes it more difficult for the system operator to balance the market and increases the need for short- and long-term flexibility.
3	Not all sources of flexibility (large-scale or distributed) are adequately valued and remunerated.
6	A power market needs to encourage technological innovation and ensure future-proofing.
8	Sector coupling will transform the demand profile by increasing and shifting the intraday and seasonal peaks. The scale of this challenge will depend on the volume of demand-side flexibility in the system.
Legend  Existing problem  New problem caused by sector coupling	

Source: BloombergNEF











7.1. Flexible technologies

Sector coupling in line with the pathway in Part 1 increases the need for more flexibility (see box) in the power system, principally due to the addition of wind and solar to meet rising electricity demand (Section 6). Flexibility is the ability of a power system to respond to changes in supply and demand over various timeframes – from seconds to years. Short-run flexibility will be needed to absorb intraday variation in wind and solar output, using options like demand response and other flexible new loads, as well as battery storage and other flexible sources of generation. By contrast, long-term flexibility requires ‘back-up’ capacity that can deliver power during the weeks of the year when wind and solar output is very low. The demand side can also affect long-term flexibility needs: the electrification of heating in particular is expected to increase the need for winter back-up.

Many technologies already provide short-run flexibility to the power sector in Europe (Table 7). On the supply side, 'dispatchable' and 'peaking' sources of generation⁹, like gas-fired power stations, provide system flexibility by being available for dispatch (potentially quickly) in response to an unexpected increase in load or fall in output (eg, caused by plant outages or reduced renewables generation). Hydropower plants can also provide flexibility to the system, although building more dams can also raise concerns over sustainability and the impact on local communities.

In addition, variable renewables can add flexibility in certain circumstances by participating in balancing markets, though their capabilities are limited. On the demand side, 'interruptible loads' such as industrial users can provide short-term flexibility by agreeing for their supply to be cut off under certain circumstances (eg, periods of high demand).

Table 7: Selected sources of power system flexibility

	Existing technologies	Emerging technologies
Supply side	 Dispatchable capacity – eg, CCGTs, hydro	 Vehicle-to-grid
	 Peaking capacity – eg, OCGTs	 Hydrogen fuel cells
Supply and demand side	 Interconnectors	 Power-to-gas (hydrogen)
	 Battery storage, pumped hydro	
Demand side	 Demand response – eg, interruptible loads	 Dynamic* EV charging
		 Smart heating, thermal storage

Source: BloombergNEF. Note: * Dynamic = responsive to market signals, eg, price.

Legend:  Short-run flexibility  Both  Long-run flexibility

New sources of flexibility

As well as increasing the need for flexible capacity, sector coupling creates the potential for more demand-side flexibility – if the right enabling policies and technologies are in place (Section 11). Examples of sources of flexible demand include:

1. **Large concentrated loads:** eg, industrial demand response, data centers, commercial EV fleet hubs.
2. **Highly distributed loads:** eg, dynamic EV chargers and heat systems.
3. **Aggregated loads:** eg, virtual power plants.¹⁰

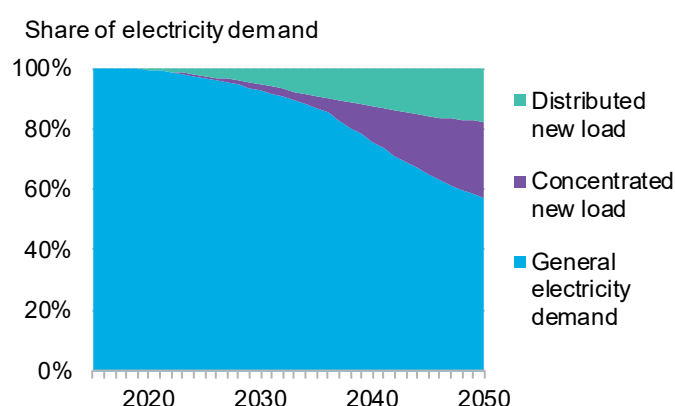
⁹ BloombergNEF defines 'dispatchable' capacity as technologies that offer bulk generation (can supply large amounts of cheap energy) but can be dispatched when needed, such as CCGTs, and 'peaking' capacity as technologies that can be dispatched in order to provide quick response when needed, such as batteries and OCGTs.

¹⁰ Virtual power plants are networks of distributed energy resources that produce or absorb electricity and are connected at the distribution level or below. Examples of these resources include PV generators, energy storage, electric vehicles, demand response. These resources are connected through a technology platform, and can operate through a variety of business models like aggregation. BloombergNEF clients may access *Virtual Power Plants 101* ([web](#) | [terminal](#)) for more detail.

Large concentrated loads

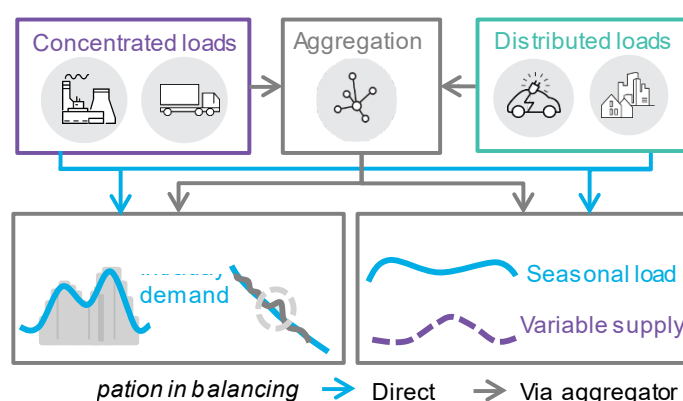
These can deliver flexibility directly to the power system through balancing and ancillary service markets, where they have access (Figure 2). Some European countries, like Spain and France, already hold demand response auctions, where large power users offer their supply as an interruptible load in exchange for preferential tariffs or other incentives. Other heavy power users like data centers can also deliver flexibility, providing upward and downward regulation in some markets like Ireland, by participating in frequency response with uninterruptible power supply sources.

Figure 26: Share of coupled demand by load type in Northern European archetype



Source: BloombergNEF. Note: Commercial buildings, industrial heat electrification and commercial EV demand are assumed to be potential sources of concentrated new demand.

Figure 27: How new loads can deliver flexibility



The sector coupling pathway implies growth in these concentrated loads, mostly in the period after 2035 as commercial and industrial end-users shift to electricity (Figure 26). Provided tariff structures and balancing mechanisms adapt, these new demand centers could also deliver flexibility services. Commercial EV fleet operators, for instance, will likely have large vehicle depots where high volumes of charging are needed. These could be interruptible or price-responsive to deliver short-run flexibility to the new load, provided adequate incentive and regulatory frameworks are in place. More broadly, electrification in industry should create opportunities for growth in industrial demand response.

Distributed loads

The electrification of buildings and transport adds more complex new loads to the system that are inherently distributed, and some mobile – in the case of EVs. These could introduce significant inflexibility to the power system if demand does not respond to market signals. However, distributed loads could offer some flexibility by using electricity at optimal times and also by participating in localized balancing services.

Some distributed sources of demand-side flexibility may be easier to unlock than others. For instance, thermal storage¹¹ can assist in delivering flexibility to the power system by converting electricity into heat at an optimal time, while storing the energy for heat delivery later on. But the flexibility of highly distributed loads for balancing and ancillary services will be challenging to

¹¹ Thermal storage relates to technologies that store heating or cooling energy for useful delivery at a later time, usually hours or days, but sometimes months.

unlock without some form of aggregation. Aggregated loads can act as an intermediary between demand and balancing markets, shifting the burden of handling power system complexity away from the consumer.

Ensuring long-run flexibility

Ensuring the long-run flexibility of the power system will be a bigger challenge. Some of the coupled sectors, especially electrified residential building heat demand, have a magnified effect on the seasonality of power demand (see the section: Impact on seasonal demand). As a result, the sector coupling pathway creates more annual variation in demand, which, in combination with more variable supply from higher volumes of wind and solar, make long-run flexibility a significant challenge.

Some technologies already provide both supply- and demand-side flexibility to some extent – eg, interconnectors between electricity networks. On the supply side, ‘dispatchable’ and ‘peaking’ sources of generation, like gas-fired power stations, provide system flexibility by being available for dispatch (potentially quickly) in response to an unexpected increase in load or fall in output (eg, caused by plant outages or reduced renewables generation). Variable renewables can also add flexibility in certain circumstances by participating in balancing markets, though their capabilities are limited. On the demand side, ‘interruptible loads’ such as industrial users can provide short-term flexibility by agreeing for their supply to be cut off under certain circumstances (eg, in periods of high demand).

Energy storage and pumped hydro also perform this dual function, as they can charge (or pump) when demand is lower than supply, and discharge when demand is higher than supply. These technologies generally improve the long-run flexibility of a system, as they integrate flexible generators over a larger region, spread the output of variable renewables resources, or reduce exposure to sources of inflexibility and extreme events like unforced plant outages. However, there are significant limits to what lithium-ion batteries can do: They become more expensive the more hours of storage they need to offer. This means that they are not good at helping to meet long-duration peaks or providing long-duration storage.

New sources of energy storage could be harnessed: for example, electricity could be converted to hydrogen when supply is abundant and cheap (ie, when renewables output is high). The hydrogen can then be stored and used at a later date (ie, when renewables output is low), helping resilience and seasonal reliability. However, the potential for power-to-gas to help with long-run flexibility is contingent on several factors, including the scale-up of the electrolyzer manufacturing industry, demand for green hydrogen, and the deployment of compatible infrastructure for transport and end-use. Today most hydrogen is produced via steam methane reforming and adjacent to the point of consumption. See Section 8.2 for discussion of the gas grid.

7.2. Impact on demand profiles

Sector coupling transforms the demand profile both on an intraday and a seasonal basis, increasing the need for flexibility in the power system. To explore this impact in more detail, we modeled three scenarios based on the pathway for direct electrification of road transport and heating of residential buildings in the Northern European archetype.¹² These sectors were selected because they are expected to be the first to electrify, and to bring more significant

¹² We modelled both the U.K. and Germany to develop a view on the pathway for the Northern European archetype and iron out some country specificities.

changes for intraday and seasonal demand profiles. In comparison, electricity consumption by industry is likely to remain reasonably flat with sector coupling, because many large industrial end-users require constant supply for their processes. In addition, electricity demand for commercial buildings will probably have a load profile more consistent with that of 'general power demand', ramping up slightly over the day and down overnight.

Approach and assumptions

Our three scenarios assume the same absolute demand inputs for direct electrification uptake by 2050, per the pathway detailed in Part 1. However, they differ in the level of demand-side flexibility (Table 8). Our modelling uses BNEF's proprietary *New Energy Outlook* modelling tools to ascertain a least-cost optimal solution for the power system. The flexible coupling scenario is our central case, while the other two highlight the impact of more extreme cases. Appendix A.3 explains the scenarios in more detail.

Table 8: Flexibility assumptions behind scenarios for sector coupling in the Northern European archetype

Scenario	Transport	Buildings	Demand response
Inflexible coupling	No uptake of dynamic EV charging.	No uptake of flexible heating.	Moderate uptake of demand response capacity.
Flexible coupling	Half of passenger EVs and a quarter of commercial EVs charge dynamically by 2050.	Well-insulated homes with a heat pump can store heat 3 hours ahead of peak demand.**	Moderate uptake of demand response capacity.
Highly flexible coupling	60% of passenger EVs and 40% of commercial EVs charge dynamically* by 2050.	Building retrofit rate doubles, allowing for higher share of flexible heating.	Demand response capacity triples compared to flexible coupling scenario.
No sector coupling	No additional direct electrification of energy demand from these sectors is assumed.		

Source: BloombergNEF. Note: *Dynamic charging assumes that power demand occurs at cheapest hour of generation. **We assume that well-insulated homes can hold heat for 3 hours, so heat pumps with this level of load shifting.

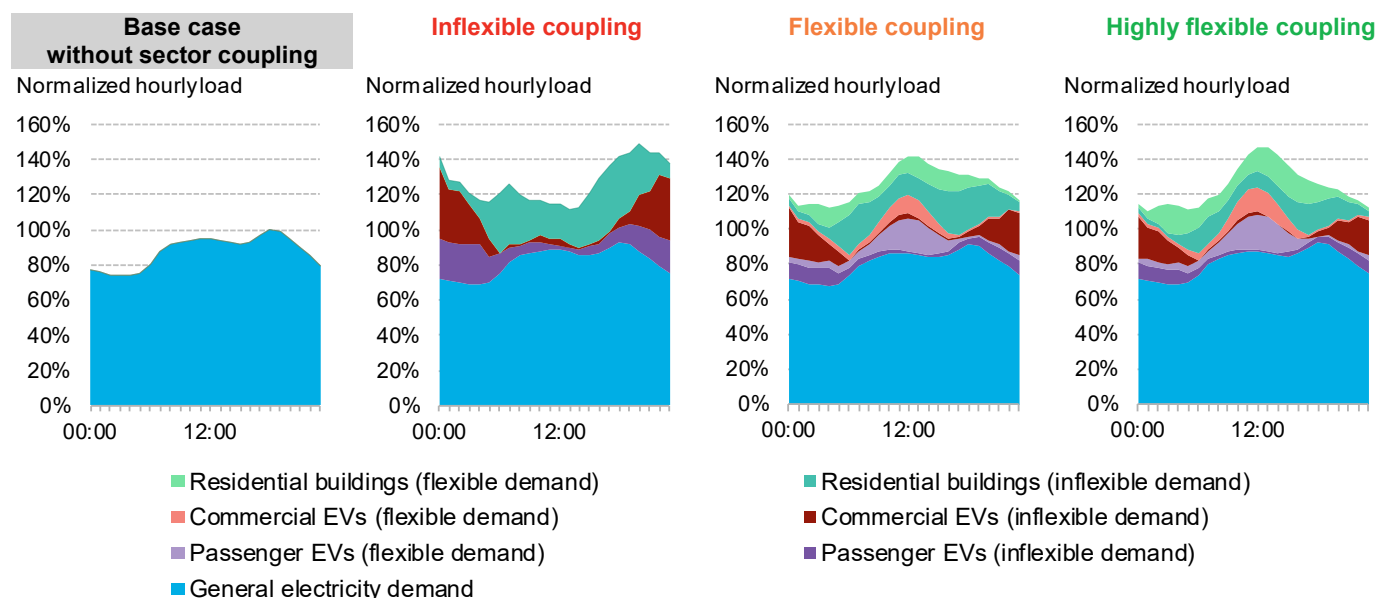
Impact on intraday demand

Sector coupling means the annual hourly peak demand in the Northern European archetype is 40-47% higher by 2050 compared with the base case, depending on the flexibility assumptions. In our analysis, less than 50% of building demand for space and water heating is electrified. With 100% electrification of heat demand by buildings, the annual hourly peak demand would be significantly higher than in our analysis.

Sector coupling also transforms the intraday profile: without it, electricity demand on a weekday in the Northern European archetype ramps up in the morning (6-9am), stabilizes and then peaks at around 5-7pm (Figure 28). However, **inflexible sector coupling** pushes up evening demand significantly compared with the no coupling scenario, with the average winter load at 8pm some 50% higher than the scenario with no coupling, and an overnight peak some 40% higher. This is because EV charging almost doubles consumption during the evening and early hours of the morning by 2050 in this scenario. In addition, the electrification of residential buildings – without

flexibility – also contributes to a peak in power demand on the shoulders of the day as people return home from work and temperatures cool.

Figure 28: Demand profiles for Northern European archetype across the scenarios (typical winter day in 2050)



Source: BloombergNEF. Note: Charts are normalized to the value of the peak load in the 'no coupling' scenario.

In contrast, increased demand-size flexibility produces a flatter intraday profile in our central **sector coupling** scenario. Demand generally ramps up for the cheapest hour of generation due to the rollout of dynamic EV charging, which also minimizes the overnight peak load. **Highly flexible coupling** produces a similar profile to flexible coupling, but allows even more electricity consumption to occur when solar (and potentially wind) output is higher (and therefore power prices are assumed to be lower).

Dynamic EV charging becomes concentrated in the middle of the day as PV dispatches during these hours at the lowest overall system cost. Overall, for these scenarios, evening demand (6p-11pm) is 20-26% lower than in the inflexible scenario and the entire demand profile of the more flexible scenarios is shifted to take advantage of solar production.

Impact on seasonal demand

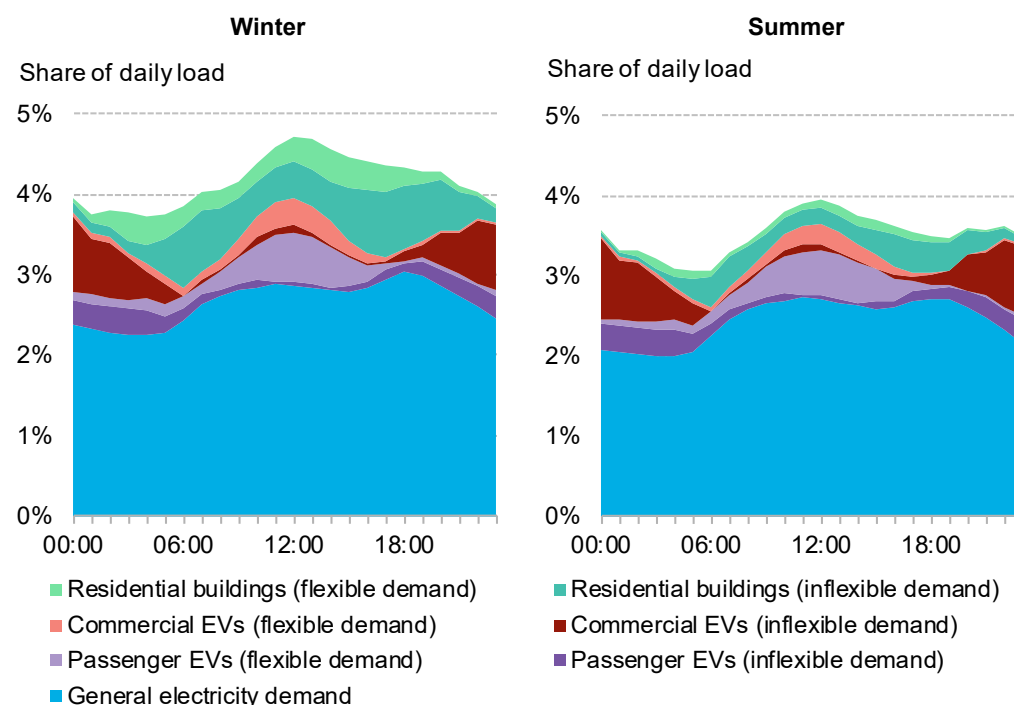
Sector coupling also affects the seasonal load profile of the Northern European archetype across all scenarios. This is driven by the strong seasonal variation in demand for space and water heating in buildings (Figure 29). The direct electrification of residential heat in the pathway almost doubles evening peak demand in winter by 2050 from 2018 levels.

This seasonality adds additional complexity to the pathway, and is likely to increase the variation in power prices between winter and summer. Power prices already have seasonal swings where significant amounts of heat demand are already electrified. In France, where 17% of heat is already delivered by electricity (compared with the European average of 12%, according to [Heat Roadmap Europe](#)), power demand is more sensitive to temperature changes, influencing prices. Average electricity prices in France in winter were almost 20 euros/MWh higher than prices in summer over 2014-18.¹³ In our pathway, the power system of the Northern European archetype

13 BloombergNEF clients may access *EU Power and Fuel Prices Tool* ([web](#) | [terminal](#)).

would face additional pressure to meet higher seasonal demand peaks in winter, and this would likely be reflected in more volatile and higher average power prices during these periods.

Figure 29: Demand profile of Northern European archetype in the flexible coupling scenario in 2050



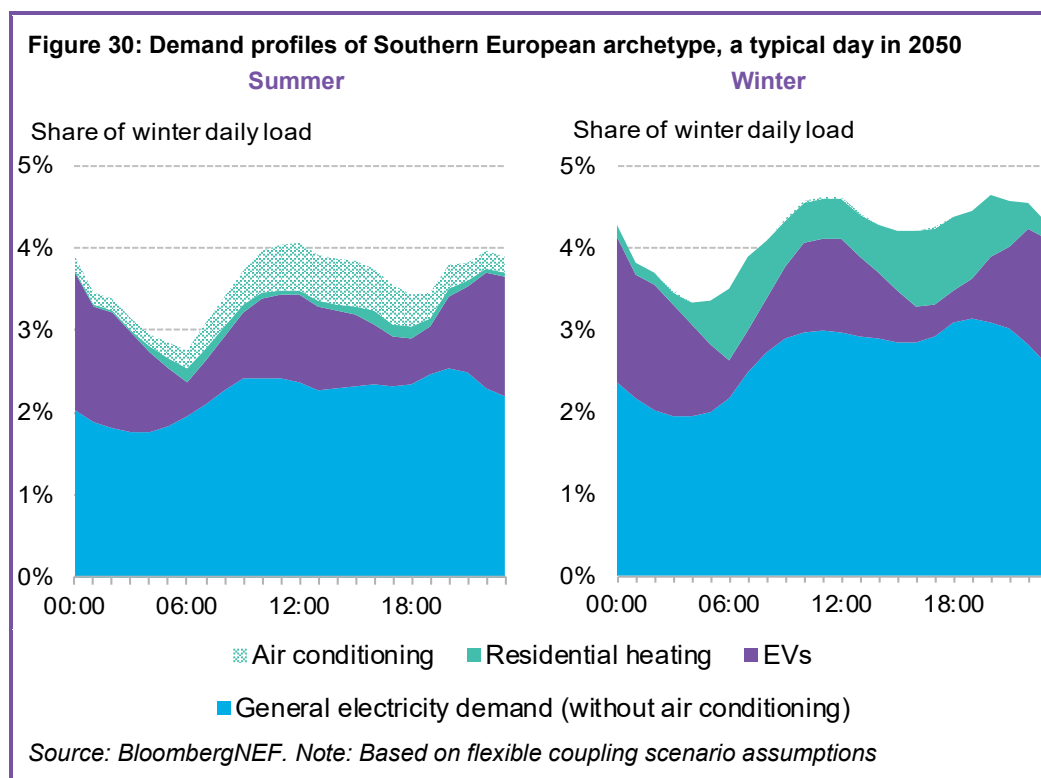
Source: BloombergNEF. Note: Normalized to value of peak load in 'no coupling' scenario.

Southern European archetype

The seasonality of power demand resulting from sector coupling in the Southern Europe archetype is less pronounced than that in the Northern archetype. This is because the Southern market is expected to increase its seasonal electricity demand for cooling in the summer and has slightly milder winters. Overall, electrified heat demand in the winter and air conditioning demand in summer are expected to have a more balanced profile in this region.

Air conditioning demand is better suited to match solar generation, as it ramps up in the middle of the day (Figure 30). However, heating demand is also needed in the morning and evening hours during winter months, meaning the Southern European archetype could also expect some additional seasonal load like in the Northern archetype.

In residential buildings, technologies such as reversible heat pump systems could deliver the seasonal heating and cooling needs in the Southern European archetype, at a more cost-effective rate than owning two separate systems.

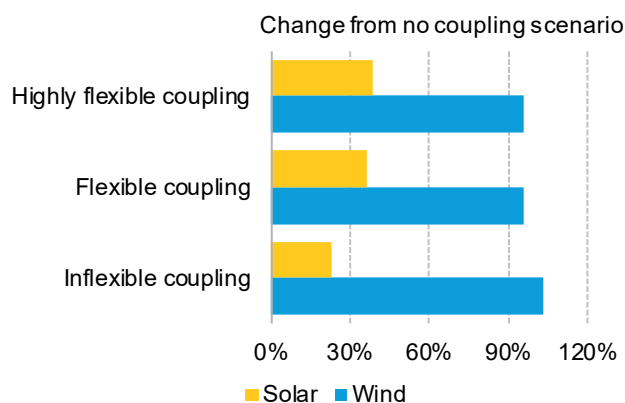


7.3. Implications

Capacity build

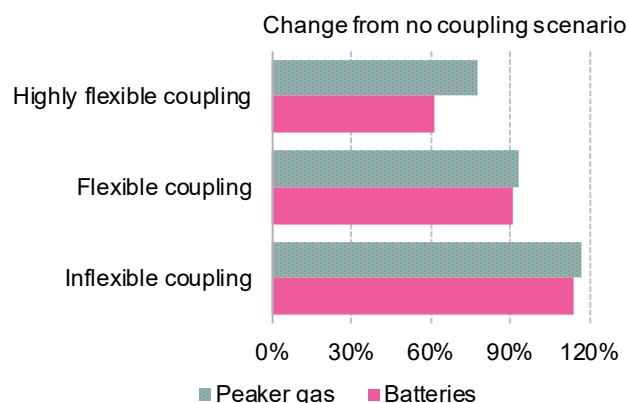
All scenarios result in significant build-out of additional renewable energy – specifically, low-cost wind and PV – compared with the base case without coupling. Twice as much wind capacity and a third more solar is built by 2050 to meet the increased demand (Figure 31). The scenarios do not integrate wind and solar to the same extent. The central flexible and highly flexible coupling scenarios enable more solar capacity to be procured: 13 and 16 percentage points by 2050 respectively more than in the inflexible coupling scenario. This is because demand-side flexibility enables the overall daily load profile to better accommodate solar generation profiles.

Figure 31: Additional wind and solar capacity build in Northern European archetype, 2050



Source: BloombergNEF

Figure 32: Additional peaking capacity build in Northern European archetype, 2050

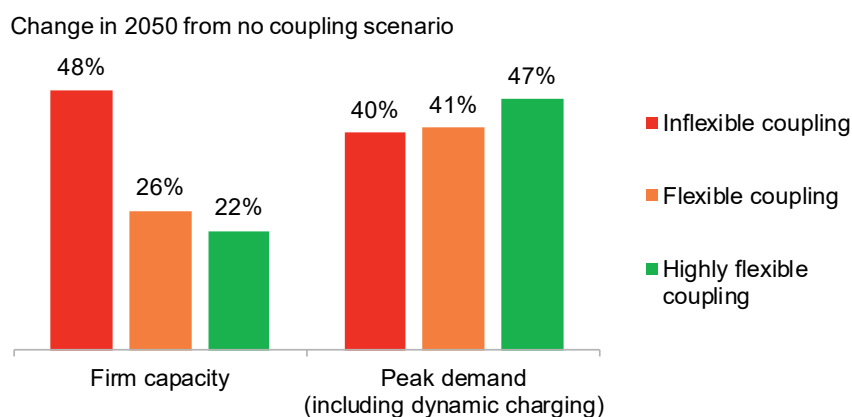


All scenarios also require more peaking capacity than the base case without coupling, in order to meet higher power demand at times when renewables aren't producing (Figure 32). The vast majority of the new flexible capacity is battery storage and peaker gas plants, principally on economic grounds. While pumped hydro is the dominant energy storage technology today, we expect limited capacity additions in Europe through 2050, due to its challenging geographic requirements, as well as local opposition and environmental impacts.

But the **flexible coupling** and **highly flexible** coupling scenarios have much less need for additional battery and peaker gas capacity than the **inflexible** coupling scenario (Figure 32). In fact, the **flexible coupling** and **highly flexible** coupling scenarios result in just *half* the firm capacity requirements by 2050, compared with the **inflexible** scenario (Figure 33). This is for two reasons:

1. **More flexible demand reduces the volume of firm capacity needed for security of supply.** This is because the seasonal winter peak in the inflexible scenario is steeper in the evening than in the other scenarios, and as a result, the power sector needs more firm capacity to deliver for the seasonal spike in electricity demand.
2. **Demand is more responsive to market signals.** Dynamic EV charging takes advantage of the cheapest hour of generation, which enables more wind and particularly solar to be used at the time of output, rather than being stored or curtailed. This minimizes the required storage capacity and optimizes the balance between wind and solar capacity build-out, because demand can better match the intraday profiles of each resource.

Figure 33: Firm capacity and peak demand in Northern European archetype in 2050 by flexibility scenario



Source: BloombergNEF.

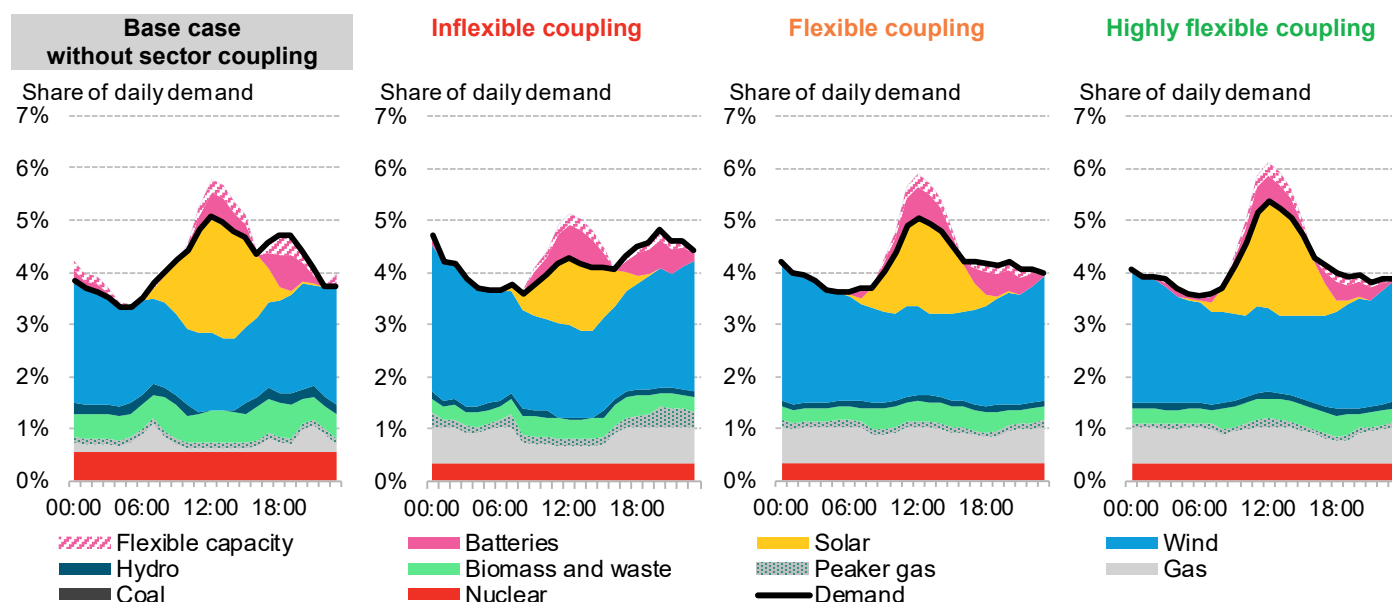
However, more responsive demand in the Northern European archetype results in higher annual peak demand by 2050. Our more aggressive **highly flexible** scenario has the highest peak of all scenarios, because more demand shifts to the cheapest hour of generation – the daytime, thanks to solar. As a result, dynamic EV charging demand could concentrate into the middle of the day – and particularly in summer this leads to a new peak. This may not be as ideal for the grid as the flexible charging assumptions in the **flexible coupling** scenario, because surges of demand in these hours could create points of local grid congestion (if charge points are geographically concentrated).

Intraday generation

The **inflexible** scenario relies on additional capacity to ramp up and deliver power in the evening and overnight. This is particularly apparent when looking at the supply mix of the evening winter peak by 2050 (Figure 34). This is when the pathway expects the highest demand from electrification of buildings and transport, and creates the steepest ramp rate to meet evening demand. In the U.K., for instance, inflexible coupling relies on batteries, flexible capacity and peaker gas to supply 8.5% of daily demand in a low-wind winter day in 2050.

The **flexible coupling** and **highly flexible** scenarios also both rely on flexible capacity to meet evening demand, but to a lesser extent than the inflexible scenario. For example, the sector coupling scenarios result in batteries, flexible capacity and peaker gas supplying 6% of daily demand in a low-wind winter day in 2050 in the U.K., while the highly flexible scenario results in these technologies supplying 5.6% of daily demand on the same day (Figure 34).

Figure 34: Generation profiles for U.K. across the scenarios: a low-wind winter day in 2050

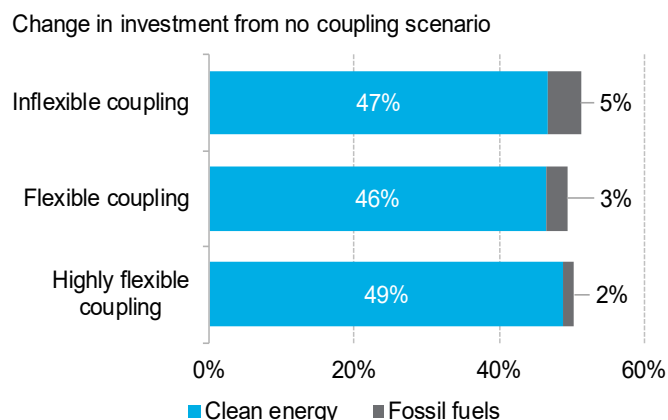


Source: BloombergNEF. Note: Demand line excludes battery charging and downward flexible capacity response.

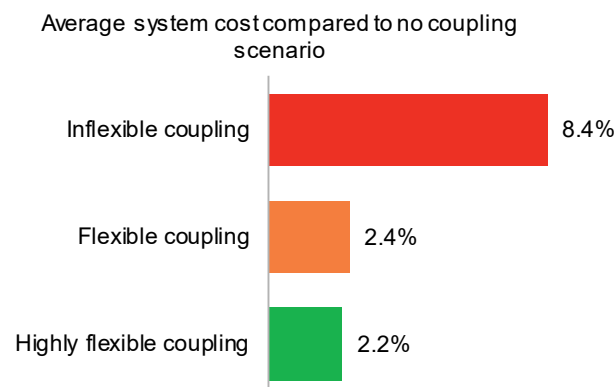
Power-sector investment and system costs

All scenarios also require higher investment in capacity additions and have overall higher system costs than the scenario with no coupling, due higher power demand in absolute terms by 2050.

Compared with the base case with no coupling, the **highly flexible coupling** scenario requires the most additional investment in new clean energy capacity – including batteries – and the least expenditure on new fossil fuel assets (Figure 35). The **inflexible coupling** and **flexible coupling** scenarios both require similar levels of investment in new clean energy capacity – but the former notably needs more fossil-fuel investment due to the greater reliance on peaking gas to deliver system flexibility. The inflexible coupling scenario, as a result, requires the most new investment of all scenarios.

Figure 35: Investment in new capacity additions by scenario in Northern European archetype

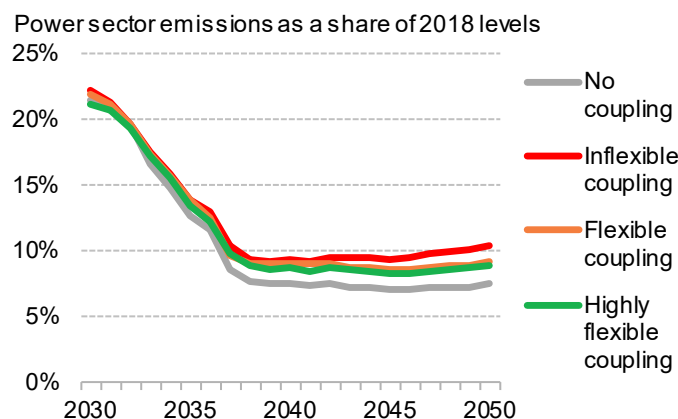
Source: BloombergNEF

Figure 36: Average system cost compared by scenario in Northern European archetype

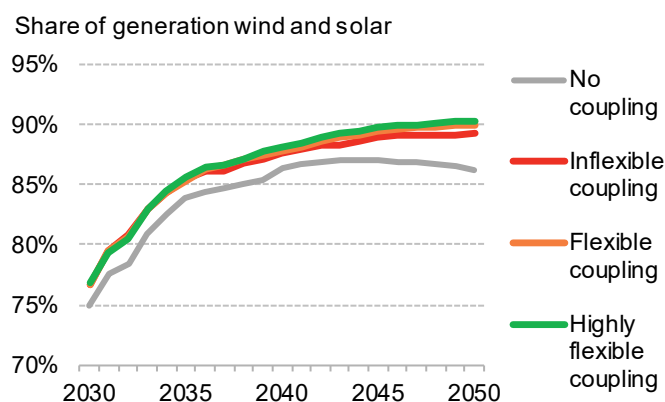
Sector coupling will not only require more investment in generating capacity, it will also increase system costs (Figure 36). Costs under the **sector coupling** and **highly flexible coupling** scenarios will be 2.4% and 2.2% higher than without sector coupling on a dollar-per-kilowatt-hour-per-year basis. However, the **inflexible coupling** scenario yields system costs 8.4% higher due to the additional strain on the supply side to balance variable renewables and the newly electrified sources of energy demand in transport and buildings.

Emissions

Power sector emissions rapidly decrease in all three sector coupling scenarios until 2035, driven by wind and solar capacity additions and the retirement of fossil fuel plants (Figure 37). By 2050, sector coupling sees around 90% of power generation delivered by wind and solar (Figure 38). However, all three scenarios yield higher power sector emissions in absolute terms than the scenario with no coupling, because the energy demand shifted to the electricity sector from previously uncoupled sectors results in higher overall power consumption in absolute terms.

Figure 37: Power sector emissions by coupling scenario: Northern European archetype

Source: BloombergNEF.

Figure 38: Share of generation supplied by wind and solar in Northern European archetype by scenario

The share of flexible demand in the system has a material impact on the extent of these additional power sector emissions in the Northern European archetype (Figure 37). More peaking gas capacity means higher power sector emissions in absolute terms compared with the base case with no sector coupling, as follows:

- The **inflexible** scenario results in 27% higher cumulative power sector emissions over 2035-50 than the scenario with no coupling over the same period. Meanwhile, the **sector coupling** and **highly flexible** scenarios yield only 18% and 15% more cumulative power sector emissions over 2035-50 than the scenario with no coupling.
- In absolute terms, for Germany the additional power sector emissions from sector coupling range from 77MtCO_{2e} in the **highly flexible** scenario to 112MtCO_{2e} in the **inflexible** scenario. Meanwhile in the U.K., the additional power sector emissions from sector coupling range from 62MtCO_{2e} to 99MtCO_{2e} in the same scenarios respectively.

Sector coupling may mean slightly higher emissions for the power sector due to higher volumes of demand. In the Northern European archetype, this is mainly due to the seasonality of power demand – necessitating dispatchable generation, delivered by peaking gas capacity. However, all sector coupling scenarios reduce *economy-wide* emissions as the alternative is for transport, buildings and industry to continue to use fossil fuels.

7.4. Investment signals and other barriers

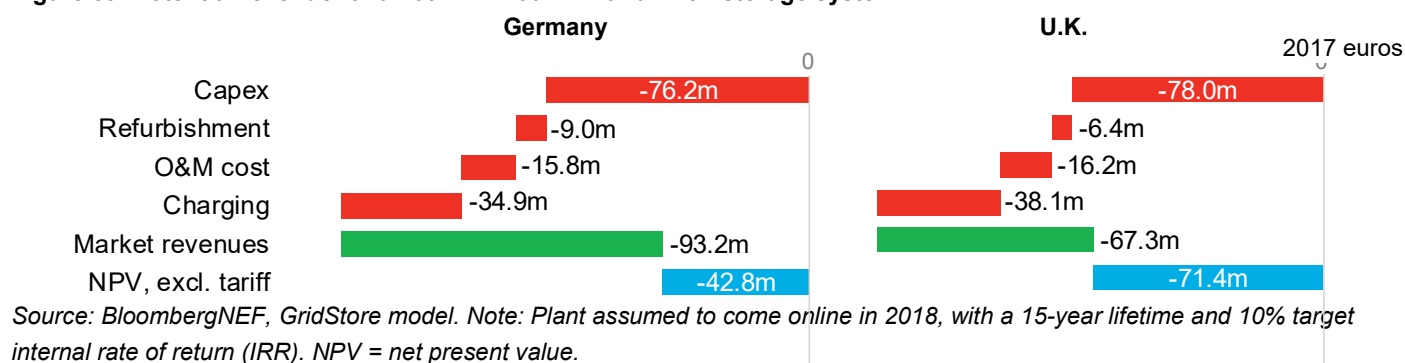
The figures above assume that the required volume of flexible capacity comes online in response to the growing share of variable generation. However, this is not a given: not all wholesale power or ancillary service markets in Europe adequately value and remunerate flexibility provision. This calls into question whether the required capacity will indeed be built.

As an example, a 200MWh/100MW storage plant that came online in 2018 would face a loss over its lifetime of 43 million euros in Germany and 71 million euros in the U.K. if its only source of revenue was the electricity market. These projections were calculated using BloombergNEF's GridStore model,¹⁴ which optimizes battery dispatch, simulating battery behavior on an hourly basis, in order to maximize project returns. Different markets offer different opportunities: In Germany, over 85% of the market revenue would be earned for frequency regulation services, while in the U.K. two-thirds would come via power-price arbitrage (using batteries to shift energy from times of cheap power to expensive peaks).

Energy storage owners, and flexibility providers more broadly, that depend on the wholesale power price face the same uncertainties as other players in the generation market (Section 5). In addition, they tend to destroy their own investment case. In theory, wholesale power price volatility will grow with the increasing share of variable renewables in the generation mix, and that favors storage.

14 BloombergNEF's GridStore model is available to clients at [web](#) | [terminal](#). This estimate assumes revenues from arbitrage and Firm Frequency Response (FFR); 5,000-cycle life for the lithium-ion battery; efficiency of 90%; depth of discharge of 80%; 15-year life; and no change in annual revenues. Costs and O&M assumptions can be found in GridStore.

Figure 39: Potential revenue for a 200MWh/100MW lithium-ion storage system



However, in practice, there may be a limit on the amount of arbitrage that can be profitable since it may dampen price fluctuations and thereby destroy these technologies' own investment case for some players at least. The strength of the dampening effect of flexible technologies will depend on the strength of the volatility-driving effect of variable renewables together with power market reform efforts. For example, shorter settlement periods would enable providers of flexibility, especially storage, to determine the value of their service more accurately and efficiently. For more on such changes, see Section 15.1.

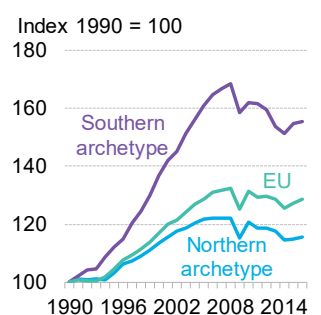
As well as concerns relating to investment signals, flexibility providers also face a raft of more practical barriers:

- **Uneven playing field:** access to electricity markets for flexible resources varies across Europe. For example, demand response assets in France may participate in the markets for frequency and reserve services, wholesale power and capacity, while in the U.K. they cannot access the wholesale market. In some cases, access is allowed on paper but is limited in practice because the rules were originally devised for traditional generators like coal and gas – or rules on connection, for example, may impede participation: in theory, demand response in Germany may provide reserve services, but restrictions on minimum bid size and aggregation, and stipulations on grid-connection sites mean that demand response providers have limited participation.
- **Conflict over balancing responsibility:** this remains a particular challenge in Europe, where energy retailers have said they are penalized for imbalances caused by demand response activated by third parties. If a supplier is responsible for balancing, it must reach an agreement with any aggregators, giving the retailer control over a customer's access to demand-response services. In such markets, these rules effectively preclude third-party aggregators from entering the market even though they play a vital role in flexibility deployment.
- **Ownership issues:** energy storage for grid investment deferral and congestion relief is contentious. Grid operators in some European markets argue that they should be allowed to own and operate storage assets and should not have to contract out these services. However, many regulators and independent generators fear such projects would distort market signals and blur the line between regulated investments and market-based competition.

Section 8. Grid

Electricity network operators will face significantly increased flows due to sector coupling, in particular at the distribution level. In addition, this upward trend will likely be bumpy and unevenly spread across the grid, while demand characteristics change. This will increase spending on congestion management measures in the short-to-medium term, and investment in grid reinforcement and extension in the longer term. Gas network operators will also be affected by sector coupling, in particular driven by the increasing use of hydrogen.

Figure 40: Power demand



Source: Eurostat. Note: EU = EU-28.

Table 9 shows the principal network-related problems potentially exacerbated or caused by sector coupling.

Table 9: Key power system problems for the electricity and gas grids

4	The increase in distributed energy resources on both demand and supply side creates challenges for grid management.
5	The grid already faces challenges due to the geographic mismatch between the location of energy resources or generating capacity, and demand centers. Such challenges are due to worsen at a local level with the growth in ICT or other industrial clusters.
6	A power market needs to encourage technological innovation and ensure future-proofing.
7	Sector coupling will substantially increase total electricity demand over the next 30 years even in markets where demand would otherwise flatten out or decline. This may be beneficial for some players in the electricity value chain but will require investment and planning, particularly for the grid
8	It will also transform the demand profile by creating steeper peaks during the day together with more seasonal variation. The scale of this challenge will depend on the volume of demand-side flexibility in the system.
9	An increase in the use of green hydrogen will raise the question of production location and transport, with repercussions for both the power and gas network.

Legend

x Existing problem

x New problem caused by sector coupling

8.1. Electricity grid

Electricity grid operators in Europe already face a growing list of challenges, including the rapid deployment of variable renewables, integration of power markets across national borders, and growing consumer engagement. Sector coupling will increase these challenges and create new ones as the electricity value chain becomes increasingly bound up with gas and hydrogen as well as more end-use sectors (Figure 43).

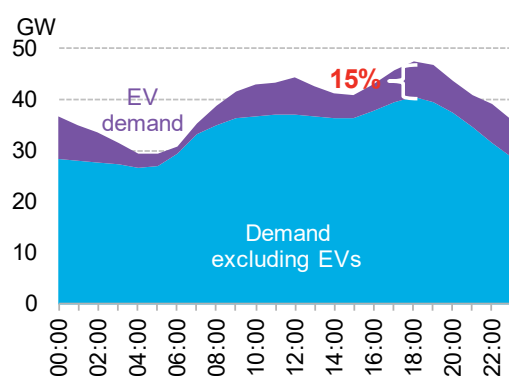
Increased power flows

The most obvious implication of sector coupling for the electricity grid is that it will increase flows on the network: over 2018-50 power demand in the transport, industry and buildings sectors in the Northern European archetype grows by some 65% (Figure 40). The primary risk is that grid reinforcement cannot keep up with demand growth and insufficient network capacity leads to

overloaded network elements and power outages. A 65% net increase in demand over 2018-50 would indeed be substantial especially given that – without sector coupling – demand would be expected to decline 15%. Of equal concern as the increase in total demand is the resulting increase in peak demand and faster ramping, as outlined in Section 7. Grid expansion will therefore need to be carefully planned but operators face a number of hurdles:

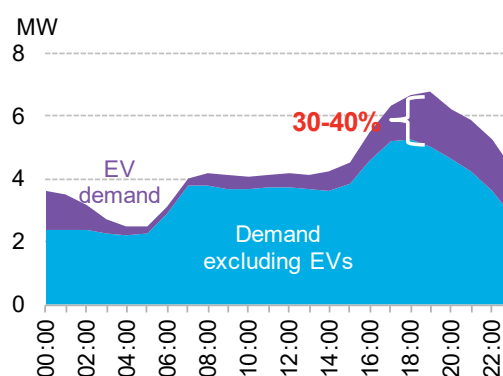
- **Bumpy path:** if the upward trend is relatively smooth, compound annual growth would equal 1.3%, which is within the historical range of electricity demand growth. The EU saw an increase of 1.4% a year between 1990 and 2010, for example (Figure 40). This would suggest that it would be practically feasible to ensure the electricity network can cope with the increased volumes in principle. However, in practice the upward trend may be bumpier and particularly steep in the second half of the period as the policy-determined deadlines approach for ICE vehicles and gas-fired heating, new technologies such as industrial-scale electric furnaces and heat pumps for higher temperatures come to market, and others reach cost parity with fossil fuels (eg, green hydrogen). The success of sector coupling is particularly dependent on how grid-related issues are managed: if increased electrification results in network outages or other grid-related challenges, this may create political backlash and consumers may be less likely to switch to electricity.
- **Non-uniform growth:** demand growth will be unevenly spread across a network as certain areas (regions, feeder sections, etc.) connect EVs or heat pumps before others, for example. Indeed, most of the additional demand will be from existing consumer sites but some will be large spot loads – eg, hydrogen electrolyzers and factories switching to power. At the distribution level, in certain areas, the increase in peak demand could be significantly higher than the increase at system level. For example, left unmanaged, U.K. peak demand would be expected to rise by 15% with EV adoption at 50%, based on a BloombergNEF report published in November 2019 (Figure 41).¹⁵ At the local distribution level, this increase could be 30-40% (Figure 42).

Figure 41: EV impact on U.K. national power demand at 50% EV adoption



Source: BloombergNEF. Note: EV charging curve = combination of passenger and commercial EVs

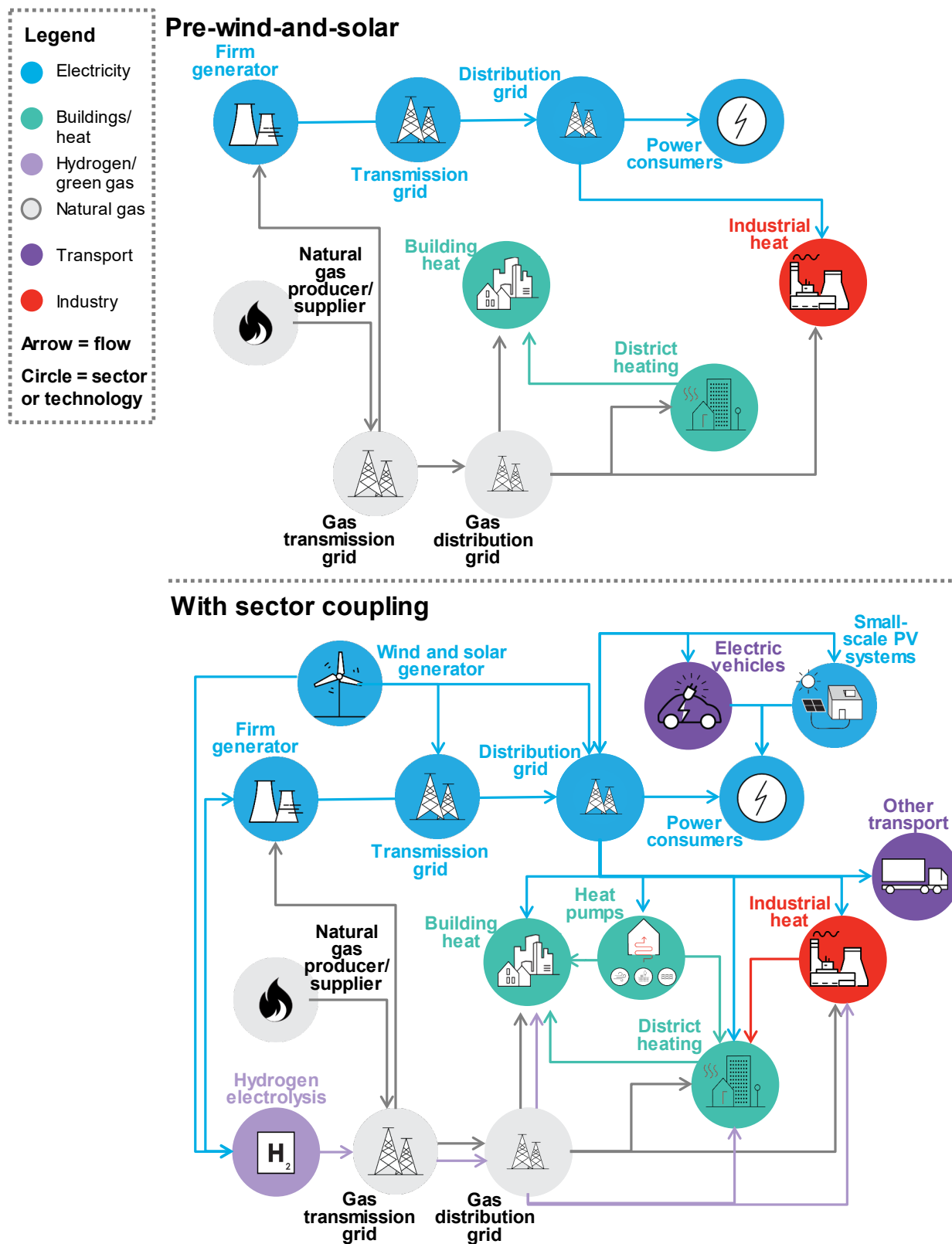
Figure 42: EV impact on typical 11kV feeder in the U.K., with 50% of houses owning an EV



Source: BloombergNEF, Western Power Distribution. Note: Winter day. Assumes all EVs are BEVs charging at 7kW.

¹⁵ BloombergNEF clients can read more in: *Gearing Up: Getting the Grid Ready for EVs* ([web](#) | [terminal](#)).

Figure 43: Evolution of the power and gas value chain



Source: BloombergNEF.

- **Lack of visibility and control:** under current rules in Europe, grid operators have little control, and relatively limited visibility, on the uptake of EVs, heat pumps and other electricity-using devices. They are also subject to regulated planning and investment cycles. If grid bottlenecks materialize, more visibility and regulatory agility may be needed to ensure system reliability.
- **Changing demand characteristics:** for the first time, a substantial component of the demand will be able to move around on the grid (ie, EVs). This may be less of an issue if – as we expect – most charging of passenger cars occurs at home for the foreseeable future. That said, public and workplace charging will become more important as those without the ability to charge at home adopt EVs. As this trend grows, the grid may need to be reinforced in multiple spots for the same load, meaning that a 1MW increase in EV demand, for example, may need 2-3MW of grid reinforcement. Grid operators are optimistic about being able to use smart charging to move the load, but there are still many hurdles to implementation that will determine its effectiveness and reach. These include the commercial viability for workplaces to make charging hardware available at scale, and drivers' appetite to plug in at times of day suitable for the electricity network. There is also much debate about the communications and ownership of the smart charging platform which will take some years to reach a conclusion. Similarly, we expect uptake of vehicle-to-grid (V2G) services to be limited, at least in the near future. If not, the distribution network will need to be upgraded because it was planned and designed on the assumption of radial supply.

Increasing burden on distribution utilities

These hurdles are easier to manage at the system level for several reasons. First, demand from EV charging is more spread throughout the day because commercial EVs, fleets and those using public charging will have different patterns from those charging at home. This will lessen the impact on the transmission network: the higher-voltage grid is generally planned with more reserve capacity than the lower-voltage grid. Second, medium- and low-voltage distribution networks serve smaller local areas, and are therefore more susceptible to a local influx of EVs, say in a particular neighbourhood or commercial cluster where EV uptake happens to be faster than at the national level.

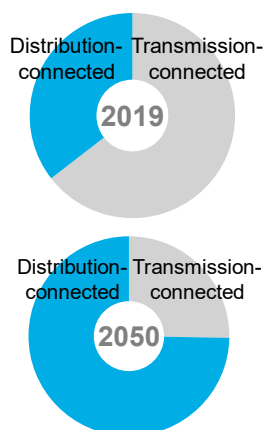
Other issues for the distribution network include overloading of low-voltage feeders and secondary transformers, and the violation of voltage operating limits. With regard to when such issues could arise, the deployment of electrified transport by itself is not expected to spark problems in the near term, with estimates suggesting a tipping point will be when EVs exceed 10% of the fleet – a point the Northern European archetype is due to reach at the end of the 2020s. An increase in electrification for heat or industrial processes will add to this challenge, although much of the growth occurs from 2030. Charging behavior (uncontrolled versus smart), simultaneity factor, generation assets connected to the low-voltage grid, network design and local grid regulations will determine which areas will face problems, as will the presence of local clusters of EV sales. These develop based on wealth, charging infrastructure density and exposure to current uptake.

Other types of geographic cluster are expected to develop over the next 30 years, with further implications for the local grid. For example, cloud providers often site many data centers within 'availability zones' in order to improve their service reliability. The location tends to be determined by the location of critical infrastructure, which includes fiber optic cables, substations, transmission lines and other data centers. Other important factors are electricity supply reliability

and prices, real-estate costs and the availability of skilled labor. Several large technology companies that run data centers – eg, Google and Amazon – also have ambitious sustainability mandates, meaning that a potential cluster site should also have access to renewable power supply (whether via the grid, private wire or on-site generation). In Europe, some countries are seeking to become a regional hub for data centers, including Ireland and Denmark.

More broadly, in addition to changes in peak demand, the growth in renewable power and distributed energy resources (DERs) (Section 7) will mean more generation assets are connected to the distribution grid, as its share of installed capacity expands (Figure 44). We therefore expect sector coupling to enhance existing pressure on distribution utilities to take on more system operator functions more quickly, and develop new systems to manage the dynamic grid, especially as they generally do not have access to the same tools for managing variability as transmission system operators (TSOs).

Figure 44: Estimated split of generating capacity connected to each grid, Europe



Source: BloombergNEF, New Energy Outlook 2019.
Note: As a share of peak demand

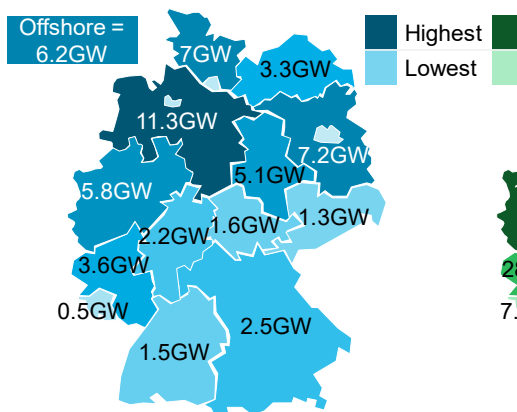
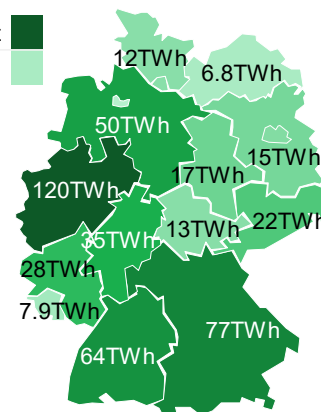
More congestion

Sector coupling is likely to exacerbate existing areas of grid congestion because it will create more demand. At the very least, the additional power demand as under the pathway would require a further 28GW of new offshore wind requiring additional transmission capacity. More renewables will lead to more network congestion and the need for more transmission capacity to connect wind and solar resources located further away from demand centers. All of this will increase the investment requirement.

An example of a grid already under pressure is the network in the Netherlands – due to the recent influx of wind and solar plants, in particular in the north-east where land prices are relatively low. As a result, distribution network operators (DNOs) Liander and Enexis have restricted connections or new projects: Liander said its “temporary” system meant that large-scale solar plants, data centers and other applicants would have to wait until network expansion had been implemented. The autumn round of the renewables auction program (SDE+) was the first time when participants had to submit a ‘transportindicatie’ (‘a transmission capacity indication’), showing there was sufficient grid capacity in the proposed project location.

In practical terms, major new demand centers that arise due to sector coupling, such as industrial facilities looking to electrify their operations, or hydrogen electrolysis projects, could experience similar challenges or delays due to insufficient network capacity, if they are sited in congested regions.

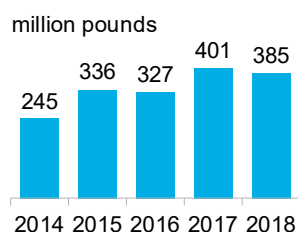
Not only will sector coupling further complicate the task of managing the electricity network as a whole, but it will also exacerbate any geographic imbalances in the system and potentially create new ones. Germany is a clear example of an existing imbalance in Europe: over two-thirds of the country’s onshore wind capacity is installed in the northern and north-eastern states (Figure 45), while the biggest demand centers are in the south and west (Figure 46). However, its north-south transmission lines were not built to carry so much load, and this has resulted in grid constraints and higher system costs. Managing the existing transmission bottlenecks costs over a billion euros a year, mostly due to redispatching, curtailment compensation and loop flows. This sum is already set to grow when Germany’s remaining nuclear power stations (many of which are sited in the south) close in 2022 and when the pipeline of just under 22GW of offshore wind farms come online by 2030. Grid expansion will cost 52 billion euros by 2030, according to the country’s four TSOs, on top of the 18-24 billion euros required for cables to the offshore wind plants.

Figure 45: Commissioned wind capacity, Germany**Figure 46: Electricity consumption, Germany**

Source: BloombergNEF, Länderbeitskreis Energiebilanzen. Note: Wind capacity as at end-2018. Electricity consumption – latest year available (2015-17).

As well as potentially posing challenges, sector coupling may also result in ways that congestion is alleviated through increased flexibility in the power system. See Section 7 for more discussion.

More power grid investment?

Figure 47: Redispatching costs, U.K. (Great Britain)

Source: National Grid

In the short-to-medium term, system and network operators will have to spend more on congestion management measures such as 'redispatching' – ie, where power plants upstream of the constraint are ordered to reduce output while those downstream are ordered to ramp up. Generators receive compensation for cost and foregone profits due to regulatory (rather than market-based, voluntary) redispatch. The U.K. has seen redispatching costs climb in recent years, reaching 787 million pounds over 2017-18 – nearly a fifth more than in the preceding two years (Figure 47). Most redispatching in the U.K. occurs when wind output in the north is high, and transmission lines to the south become congested. In the Netherlands, Tennet has said it is exploring the use of curtailment or connecting solar plants without a back-up connection, to create more capacity on the grid.

Thankfully, the impacts of sector coupling are mainly felt over a longer horizon. In the long term, network operators will have to build more grid capacity and other infrastructure at the distribution level, and to a lesser extent the transmission level. This process will require substantial investment and take many years, and some new capacity may only be used at irregular times when peak demand is especially high.

It will be challenging for grid operators to ensure their investment plans are based on an accurate picture over a sufficiently long timeframe. For example, some industry players are concerned that current plans may be based on increased uptake of EVs but fail to account for more electrification beyond the transport sector. As a result, upgrades may not be done in time or additional works may be required, thereby increasing the cost and disruption of network reinforcement, in particular in highly populated areas. This short-sightedness may be influenced by lack of data and other factors. See Section 12 for discussion of these issues.

8.2. Gas grid

Today, the networks for transporting electricity and natural gas are largely separate, apart from cases where gas is used for power generation. However, the sector coupling pathway expects interaction between grids to increase – whether through power-to-gas, gas-to-power or a hybrid. Hydrogen from electrolysis, for example, is seen playing a substantial role in the buildings and industry sectors by 2050. This raises the question of how and where the hydrogen will be produced – a question that would have repercussions for the electricity and gas networks.

Captive versus merchant hydrogen production

Nearly all of the hydrogen used today is ‘captive’ – ie, it is produced adjacent to the point of consumption – and we expect this option to be taken up by some industrial users over the next 30 years, in particular those that already use or produce hydrogen as by-product. (It is important to note that most of this hydrogen is produced from methane and is therefore not ‘clean’ unless CCUS is also used.)

Green gas

We focus on the implications of hydrogen for the gas grid below and in Section 13 for a couple of reasons. First, it is the more significant in terms of impact on the gas infrastructure. While green gas can refer to both hydrogen and biomethane, only hydrogen requires existing infrastructure to be modified/adapted for compatibility. Second, hydrogen has the more interesting ramifications for power networks, as its production can rely on electrolyzers and is a form of indirect electrification

For ‘green’ hydrogen, the economics are generally slightly in favor of on-site or at least close-by production. However, the cost difference would only be some 10% since hydrogen flows much faster through a pipe because it is significantly lighter, meaning the difference in energy flow is between 2% and 20%. In terms of transport costs, high-capacity pipelines will likely remain the cheapest option for the foreseeable future, according to BloombergNEF analysis.¹⁶ Trucks can be economic for transporting low volumes of hydrogen over a short distance, while ships can be used for long-haul trips but are very expensive.

While some industrial companies are likely to opt for captive production, this is not feasible for heating most residential and commercial buildings. A growing share of hydrogen will therefore need to be ‘merchant’ – ie, manufactured off site and then transported to the point of consumption. More merchant production will increase the need for hydrogen transport capacity and thus the burden on the gas transmission and distribution network. It may also create demand for dedicated hydrogen pipelines to connect producers and consumers. At the same time, greater use of hydrogen could reduce electricity demand and thus the burden on the electricity network.

We expect countries to favor using the existing gas grid: not only would this reduce the investment required for upgrade of the electricity network but it would also defer decommissioning costs for the gas infrastructure and potential stranded assets. Such savings in Germany would amount to some 12 billion euros a year by 2050 compared with a scenario where gas networks are not used, according to research by Frontier Economics.¹⁷ Indeed, the successful coupling of the power and gas networks is likely to require careful locational planning. Because transport will

¹⁶ BloombergNEF clients can access *Hydrogen: The Economics of Transport & Delivery*, 2019 ([web](#) | [terminal](#)).

¹⁷ Frontier Economics, *The Importance of the Gas Infrastructure for Germany's Energy Transition*, 2017. Cost saving estimate in real terms expressed in 2015 values.

be primarily via the gas network at least initially, companies choosing where to site hydrogen production will need to take account of the location of suitable feed-in points to the gas grid. Producers of green hydrogen will also have to account for the availability of a connection to the electricity network or access to nearby renewables.

Upgrade requirement

As explained in Section 2, the Northern European archetype begins to convert the gas network from the 2020s, to either green gas (a combination of synthetic gas, biogas and renewable hydrogen) or to 100% hydrogen networks. At low levels, blending hydrogen into the existing gas grid would require some relatively minor upgrades to the network and possibly some older appliances. Most studies find that 5-20% blending by volume is achievable in a typical, existing gas network. Blending delays the substantial capital costs in developing the required new infrastructure. However, it would pose various hurdles, as follows:

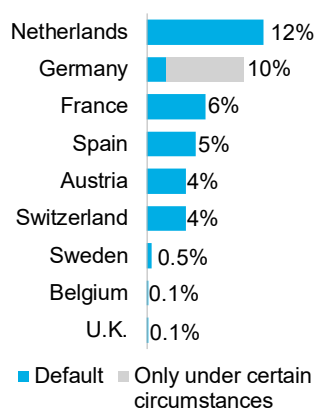
- Hydrogen has lower energy density, requiring higher volumes of gas to deliver the same amount of energy, although this is partly offset by higher flow velocity.
- The variability in the volume of hydrogen blending into the gas stream could damage the operation of equipment designed to accommodate only a narrow range of gas mixtures, and the product quality of some industrial processes.
- Hydrogen blending limits for the gas grid vary across jurisdictions (Figure 48) and depend on the pipelines and appliances connected to it, meaning each network might need to be evaluated on a case-by-case basis. Another challenge would be industry, where some applications have not been certified or assessed in detail for hydrogen blending.

In the longer term, the areas that switch to biomethane or biogas will not require network modifications. However, for the 100%-hydrogen areas, new transmission pipelines will likely be required because most of the existing stock are composed of high-carbon steel, making them susceptible to hydrogen embrittlement at high operating pressures. New hydrogen-compatible components will also be needed – eg, compressor stations, metering and valves.

The existing distribution grid will also need to be made hydrogen-compatible. Some countries such as the U.K. face lower costs because they have already replaced most steel pipes with pipes using polyethylene (PET), which is compatible with hydrogen. However, they will still need to build large-scale hydrogen storage within the gas network to deal with fluctuations in supply and demand. In addition, all heating and gas-fueled appliances will need to be replaced. Using the gas grid for hydrogen should also avoid or at least reduce decommissioning costs: for example, it would cost some 23.1 billion euros to dismantle and secure pipelines in Germany's gas distribution and transmission grid.¹⁸ Overall, we expect gas networks to transport less gas in a coupled future because much of the increase in direct electrification takes away demand from gas. This will outweigh any demand for transporting clean gas.

Such a switchover would be time-consuming and disruptive but it has some precedent: between 1967 and 1977, Great Britain converted from town gas¹⁹ to natural gas, which had been discovered in the North Sea. At a cost of 600 million pounds in 1977 (c.10.6 billion euros in 2018 prices), this process required some 40 million appliances belonging to 14 million customers to be modified or exchanged.

Figure 48: Hydrogen blending limits for natural gas networks in selected European countries



Source: Fuel Cells and Hydrogen Joint Undertaking, BloombergNEF

¹⁸ ibid.

¹⁹ Town gas was produced from coal and comprised some 50% hydrogen, with the remainder being methane and carbon monoxide.

Part 3

Implications for policy and regulation

Contents

[Click on the link to jump to that section](#)

Section 9	Overview
Section 10	Enabling sector coupling
Section 11	Unlocking demand-side flexibility
Section 12	Making the best use of power networks
Section 13	Facilitating power-gas integration
Section 14	Ensuring investment signals in generation and flexibility



Section 9. Overview

This part of the report seeks to highlight how policy makers and regulators could address some of the biggest challenges to help enable a successful sector coupling. As before, we focus on the Northern European archetype but the approaches discussed could well be applied elsewhere.

Sector coupling is a massive undertaking with policy implications in every sector: power, gas, transport, buildings and industry. Our aim here is not to be comprehensive, nor to address all of the challenges in decarbonizing all of these sectors. Instead, we offer some thematic ideas on the policy implications of sector coupling, with a center of gravity around the power sector and market design. It is still very early days for the sector coupling discussion, with much yet to be learned, and we hope that these sections offer some stimulus for further discussion.

Brexit and sector coupling

Although the U.K. left the EU on January 31, 2020, BNEF expects the country to maintain its commitment to decarbonization and keep its regulatory framework broadly aligned with the bloc. The U.K. has legislated a target to achieve net-zero greenhouse gas emissions by 2050 and – like other European governments – it has a strong incentive to pursue the electrification of other areas of the economy given the rapid emission reductions already achieved in the power sector. In the short-to-medium term, we anticipate that the U.K. will remain part of the European Emission Trading System while it sets up its own equivalent program. While Brexit may result in a period of uncertainty over trade, in the medium term the U.K. will have a strong incentive toward regulatory harmonization due to the significant interaction between its electricity and gas markets and those in the EU.

The table below outlines potential actions for policy makers and regulators to address the most important problems for the power system exacerbated or created by sector coupling.

Table 10: Policy actions for successful sector coupling

Action	Priority level
Enabling sector coupling	
Ensure that the coupled sectors are incentivized to reduce emissions, with particular focus on buildings and heat	High
Support early efforts to demonstrate the viability of integrated energy systems and support their roll-out	High
Boost public acceptance of wind and solar power build, and incentivize communities and companies willing to be early starters for sector coupling	High
Accelerate efforts to revise the EU rules on energy taxes in favor of renewable power and gases, and electricity for sector coupling technologies and for hydrogen electrolysis – eg, a tax exemption for power purchased for green hydrogen production	Medium
Promote energy efficiency to reduce impact of sector coupling, particularly in existing building stock and rental properties	Low
Iron out regulatory barriers to green hydrogen production and injection into the gas grid	High
Introduce incentives to support the development of a market for green hydrogen to drive investment and reduce electrolyzer costs	High
Unlocking demand-side flexibility	
Ensure flexible tariffs are available to all end-users	High
Implement incentives and raise consumer awareness to maximize the deployment of flexible tariffs	High
Avoid being too prescriptive on flexible tariff structures, to enable retailers to adapt to changing market and consumer needs	Medium
Ensure network charge structures deliver accurate signals to alleviate grid constraints and make best use of distributed energy resources	High
Consider how to best protect vulnerable consumers	High
Standardize new appliances and roll out smart meters to provide the infrastructure needed for flexible coupling	High
Create a level playing field for flexible resources to enable their full participation in the market	High
Refine ancillary service products and arrangements to better reflect the value provided by flexible resources	High
Facilitating power-gas integration	
Finance detailed study into the optimal location for electrolyzers, taking account of the location of demand, the power and gas grids, and renewables resources	Medium
As the hydrogen sector matures, facilitate the planning process by publishing a list of favorable potential sites for electrolyzers, taking account of the nearby gas and electricity grids as well as the location of demand and renewables resources	Low
Fund large-scale projects to demonstrate the safety of the full hydrogen process chain from end to end	High
Begin awareness-raising campaigns in favor of power-to-gas well before work begins, highlighting why low-carbon heating is required, and consider offering incentives to early switchers	High
Support research and pilots on how to address technical and legal barriers to increase hydrogen usage	High
Harmonize and then raise hydrogen blending limits, and address ownership constraints of power-to-gas assets	High
Encourage collaboration between the gas and electricity sectors at all levels of government	Medium

Action

Priority level

Making the best use of power networks

Advocate the use of transparent, collaborative planning processes for large network projects and implement incentives to boost public support	High
Promote additional power market integration to reduce the required investment in electricity grid extension	Low
Fund pilots for local flexibility markets and consider how to incentivize DSOs and energy retailers to take on more responsibilities	Medium
Strengthen locational pricing signals to ensure that the electricity network capacity – needed due to sector coupling – is built where it is most needed, and new sources of supply and demand taking of power grid constraints in siting decisions	High
Strengthen data visibility and communication channels among grid operators, and with the newly coupled sectors	High

Strengthening investment signals in generation and flexibility

Implement measures to give renewables developers more revenue certainty and ensure sector coupling does not result in higher emissions due to capacity mechanisms	High
Encourage large power users in the newly coupled sectors to sign renewable energy PPAs, also helping to mitigate the missing money problem for renewables	Medium
Support other sources of revenue certainty for flexibility providers – eg, capacity markets and firming requirements. Otherwise there may be insufficient flexible capacity to mitigate the increase in variation generation due to sector coupling	High
To ensure the flexible resources needed for sector coupling are fully remunerated, strengthen pricing signals on the wholesale markets through shorter and aligned dispatch intervals and financial settlement periods, and shifting gate closure closer to the real-time delivery of power	Medium

Source: BloombergNEF

Section 10. Enabling sector coupling

As outlined in Section 4.2, the sector coupling pathway assumes a range of policy measures to kickstart the transformation in energy use. These include sector-specific measures that are already in place or under serious discussion in various countries, such as an end to sales of internal combustion vehicles, and limitations on gas grid connections for new buildings.

In addition, there are various high-level actions that policy makers and regulators could take if they wish to facilitate the overall process of sector coupling. That is the focus of this section. First, they should ensure the coupled sectors are subject to a carbon price, and that energy taxes promote the switch away from fossil fuels. Energy-efficiency gains must be pursued, to reduce the additional power demand needed to meet sector coupling, while policies are needed to appease public opposition to wind and solar build. For gas, government should implement incentives to support the development of a market for green hydrogen and iron out regulatory barriers to its use.

Sector coupling will mean changes for the entire electricity value chain together with the coupled sectors, the gas system, all levels of government and consumers. It will therefore be important for policy makers to be transparent and to communicate effectively and in good time the need for electrification, how it will be implemented and how each party will be affected. This will be particularly important for consumers: they have been relatively unaffected by the energy transition to date but would be more affected by sector coupling (such as changes to gas-fired appliances in order to switch to 100% hydrogen).

This section discusses the most important cross-cutting policy changes needed to make possible sector coupling in line with the pathway. The pathway itself is based on additional policy assumptions not described here – see Section 4 and Table 3.

10.1. Emission policy

Recommendation:

Ensure that coupled sectors (in particular buildings) are incentivized to reduce emissions – whether through a carbon price, regulation or incentives

To achieve decarbonization through sector coupling, the transport, buildings and industrial sectors must be incentivized to reduce greenhouse-gas emissions. For some sectors, government policies are already in place to enable the scale of electrification envisaged in the sector coupling pathway as outlined in Part 1. For example, much of industry is covered by the EU ETS, although some participants continue to receive generous free allocation of emission allowances. (Section 4.2 outlines our carbon price forecast and Appendix A.3 explains our assumptions regarding carbon leakage.)

In transport, EV sales in the Northern European archetype are buoyed by the CO₂ targets that were finalized in 2019. These require emission reductions of 15% and 37.5% by 2025 and 2030,

with respect to the 2021 levels.²⁰ Ultimately to 2050, ETS targets will need to be raised, free allocation to industry reduced and carbon leakage concerns addressed so that the impact of free allowances can be removed. While EVs reach cost parity during this period and start to grow quickly, this may not be enough on its own to make the full switchover for all road users: policy action may be needed to address challenges such as availability of charging infrastructure.

However, policy action is needed to spur the coupling, and thus decarbonization, of the buildings sector. This is principally because we do not expect the economics to be sufficiently favorable by themselves to spur space and water heating systems to switch to electrification technologies. The pathway outlined in Part 1 assumes that government opts for command-and-control regulation by banning the connection of new residential and commercial buildings to the gas grid from 2030, for example. This is not the only available approach: alternatives would be to require heating suppliers to pay a carbon tax such as those in the Nordics, or participate in an emission-trading scheme like that planned in Germany.

10.2. Energy taxes

National governments should support and accelerate efforts to revise the EU rules on energy taxation to facilitate sector coupling. Without this reform, the increased use of hydrogen and renewable power envisaged by the sector coupling pathway will not be possible. Because the EU energy tax directive has not changed since it came into force in 2003, it does not reflect technological advances in areas such as renewable energy, EVs, battery storage and renewable gases like hydrogen.

Recommendation:

Support and accelerate efforts to revise the EU rules on energy taxes in favor of renewable power and gases, and electricity for sector coupling technologies

As a result, the European Commission initiated in 2019 a process to reform the directive, and has asked the Parliament and Council to use qualified majority voting to make decisions, rather than unanimity.²¹ Such a move would streamline the process but will be controversial. A revised version of the directive is due to be released by June 2021, according to the European Green Deal announced in December 2019.

Policy makers should pay attention to five main areas to enable sector coupling to happen:

- **Higher rates for all energy products:** the minimum rates are set so low they barely have an effect. Governments could incentivize energy efficiency by increasing these tax rates as a way to lessen the impact of sector coupling. Rebates or other measures could be offered to low-income households or industrial sectors at risk of carbon leakage.
- **Higher rates for fossil fuels than for electricity:** taxes and levies account for a growing share of retail power prices – 33% in the EU in 2018 compared with 23% a decade earlier. In addition, despite increasing renewable power generation, taxes comprise a smaller share of natural gas prices for heating and electricity across the majority of member states (Figure 49). EU governments are unlikely to agree to implement a mandatory higher tax rate for fossil fuels. But this could be made optional.
- **Lower rates for renewable power and gases:** current rules allow member states to offer tax exemptions and reductions for renewable power and combined heat-and-power (CHP). These could be made mandatory as a way to incentivize deployment. Similarly, governments could offer preferential treatment to low-carbon alternatives to natural gas, such as hydrogen,

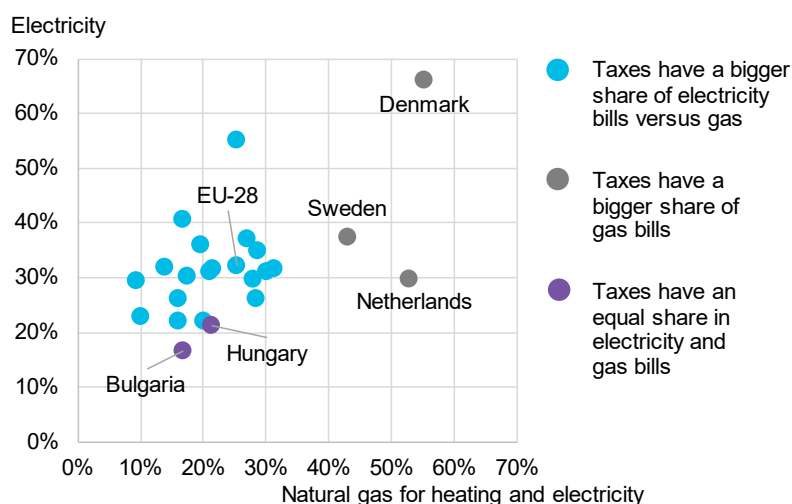
²⁰ We do not assume these targets are met – our analysis is based on planned vehicle launches and current EV support policies in the short term and increasingly economics from the latter half of the 2020s.

²¹ For a proposal to be approved under qualified majority voting, at least 55% of member states must vote in favor and those countries must represent at least 65% of the total EU population.

biomethane and renewable fuels of non-biological origin. Given that hydrogen plays such a crucial role in the sector coupling pathway, government could consider scrapping taxes on power purchased for green hydrogen production.

- **Lower rates for electricity for sector coupling technologies** such as EVs and heat pumps: rules could be amended to include a lower minimum level of taxation for power used in the coupled sectors. Government could also consider introducing favorable treatment for power when purchased for hydrogen electrolysis.
- **Electricity for storage:** to ensure that the power system incorporates sufficient flexibility to complement the increased wind and solar generation, governments should harmonize rules on how to treat energy storage and ensure that the same megawatt-hours of power are not taxed twice – when it is stored and re-sold.

Figure 49: Share of retail household energy bills comprising taxes and levies (2018)



Source: Eurostat, BloombergNEF. Note: Gas = all household consumption bands. Electricity = consumption bands DA and DB.

National governments should also look to ensure the country-level tax framework supports sector coupling and takes account of technological advances. For example, in Germany power-to-gas plants are classified as electricity end-users and therefore pay various taxes and charges, increasing green hydrogen prices. In addition, government should consider how to incentivize the newly coupled sectors to sign power purchase agreements.

10.3. Public acceptance of wind and solar build

As explained in Section 3, sector coupling doubles the additions of wind and solar generating capacity over 2018-50, according to our economics-driven analysis.

However, it may not be possible in practice to add this volume of new wind and solar power plants, given the level of public opposition against local renewable energy deployment in various European countries. Taking Germany as an example, some 1.2GW of onshore wind projects were blocked by legal objections based on the alleged threat to endangered birds and bats as of 4Q 2019, according to industry association Bundesverband Windenergie. A survey published in July 2019 found that the top five grounds for legal action against onshore wind in Germany were

Recommendation:

Boost public acceptance of wind and solar power build, and incentivize communities and companies willing to be early starters for sector coupling

species protection, procedural errors, noise protection and planning laws.²² Such public opposition has also been seen in the U.K., the Netherlands, Ireland, France and Poland.

These cases may not reflect the opinion of most EU citizens: it is important for national governments to set ambitious targets to increase the amount of renewable energy used, according to 92% of respondents to a survey published in April 2019.²³ But they can have a material impact on new build: environmental litigation – together with land shortages and drawn-out lead times for projects – meant that additions of onshore wind capacity in Germany in 2019 were at their lowest level for at least a decade. With many of the best wind sites already used by existing plants, the issue relating to suitable land has been compounded by state-level regulations governing the distance between wind farms and residential areas. These have now been reinforced by national-level restrictions that were passed by the Parliament in November 2019. Several states have now imposed limits on wind-farm permits, as growing support for far-right parties in some regions has further reined in construction. Germany is not alone in hindering wind deployment: In the U.K., onshore wind developers face a raft of planning restrictions and policy uncertainty, while projects in France are hindered by red tape and legal challenges.

It will therefore be important for policy makers to take steps to boost public acceptance of renewables. For example, in Denmark if a house value declines due to a nearby onshore wind farm, the operator must award compensation. In addition, at least a 20% share in the project must be offered to local residents, and the community receives a direct allocation per megawatt of power generated. For Ireland's new auction scheme, each winning developer has to contribute to a community benefit fund at a rate of 2 euros per MWh per year. This should result in at least 6 million euros each year for communities living close to renewables projects. These will also have the chance to invest in projects.

As well as incentives to increase public support for wind and solar, policy makers could incentivize communities and companies to be early switchers away from fossil fuels.

The U.K. 'Freedom' project involved finding 75 homes in which a hybrid heating system was installed: of this total, 40 were provided by the local social housing association and the remainder were secured through the support of a local member of parliament, council and organizations (eg, a college, utility and local employer). As well as undertaking an awareness-raising campaign among the local community, companies undertaking similar projects have recruited participants using the following incentives:

- Installation and service of new appliances – in some cases, the project covered all upfront costs and in others it financed the additional cost on top of the price for a conventional equivalent appliance (eg, a gas boiler for a heat pump)
- Reduced electricity and gas bills
- Financial payments and vouchers – as a one-off or in regular instalments after a certain stage was completed or for continued participation
- Collaboration with a recognized university (to boost credibility).

22 Fachagentur Windenergie an Land, Hemmnisse beim Ausbau der Windenergie in Deutschland, July 2019.

23 Eurobarometer, Citizen Support for Climate Action, April 2019.

10.4. Hydrogen

Incentives

Recommendation:

Introduce incentives to support the development of a market for green hydrogen to drive investment and reduce electrolyzer costs

Hydrogen plays a key role in the sector coupling pathway for the Northern European archetype. For this to become a reality, government should focus on how to create and then support a market for green hydrogen in order to drive investment and reduce electrolyzer costs. Indeed, the sector coupling pathway assumes that a 'hydrogen economy' develops and demand for green hydrogen expands substantially.

There are signs that policy makers are focusing more seriously on the potential of green hydrogen: it is a priority area in the European Green Deal, in particular for transport and industry. In addition, three-quarters of EU member states include the gas in their national energy and climate plans (NECPs), for example France which aims for 10% of gas consumption to be renewable by 2030. However, most plans lack clear goals and concrete actions.

Binding targets for green hydrogen or blending mandates would help to give the sector long-term visibility on future demand. They could be based on the share of gas injection or consumption, or all current grey hydrogen²⁴ production for industry should have to switch to green (or blue).

In addition, policy makers should introduce measures to achieve these targets. Few countries offer hydrogen subsidies, with most of those that do exist applying to the transport sector. Temporary support schemes could be set up, such as grants, auctions for contracts-for-difference or feed-in tariffs. Policy makers could also incentivize the use of excess wind and solar power for hydrogen electrolysis. This would reduce the volume of new generating capacity needed to meet rising power demand and cut the cost of sector coupling.

Measures to disincentivize natural gas would also help create demand for hydrogen: for example, the emission threshold for capacity markets in the EU could be lowered, reducing potential participation by fossil fuel plants. In addition, government could fund further research and demonstration of hydrogen use in buildings and industry (Section 13).

Regulation

Recommendation:

Iron out regulatory barriers to green hydrogen production and injection into the gas grid

Policy makers should put in place a harmonized regulatory framework adapted to the needs of hydrogen (and green gas), as well as addressing barriers to uptake (Section 13). At least some of these issues should be addressed in the forthcoming EU legislative package on the role of gas in decarbonization. Example issues requiring policy intervention are as follows:

- There is **no agreed EU definition** of renewable gases, green or low-carbon hydrogen, and power-to-gas. The lack of such a bloc-wide definition has resulted in a patchwork of rules across member states relating to trading, gas-grid connection and injection, and tax treatment.
- It will also be important to ensure that all users – whether producers or consumers – can **access the gas grid** on a non-discriminatory basis. See Section 13.3 for discussion on the issue regarding ownership.
- The **state aid rules** for environmental protection and energy should be amended to include green hydrogen in the list of electro-intensive sectors. This would mean such projects would be eligible for renewables government support.

24 Grey hydrogen is defined here as steam methane reforming without CCUS or non-renewable electrolysis.

- To facilitate the creation of a hydrogen market, policy makers should iron out barriers to the use of **guarantees of origin** (GOs) for this technology. These certificates enable countries to fulfil fuel-mix disclosure requirements, and corporates to track the origin of their energy purchases, making them key to the PPA market. An example of a barrier is the lack of harmonization across the national schemes so GOs are not necessarily interchangeable.

A remaining challenge is timing: even if the European Commission releases the legislative package in 2020, it could be several years before it is passed and then implemented by member states.

10.5. Energy efficiency

Government and the energy sector could reduce the impact of sector coupling (and reduce emissions) by incentivizing a reduction in energy consumption by the coupled sectors. As a first step, energy subsidies could be scrapped, except for very low-income households. Not only should this strengthen pricing signals but it would also reduce government spending, which could be allocated to energy efficiency initiatives. Some countries have implemented targets but these are often ineffective without measures to implement them. The EU is broadly on track to achieve its non-binding 20% efficiency target, although a third of the demand reduction has been due to the economic crisis that unfolded in the years after 2008.

Recommendation:

Promote energy efficiency to reduce impact of sector coupling, particular in existing building stock and rental properties

In addition, under the EU energy efficiency directive, energy distributors and retailers have to achieve annual energy savings equivalent to 1.5% of annual sales to final consumers. These can be realized through obligation schemes requiring companies to implement energy-saving measures (eg, insulating roofs). Or governments can implement 'alternative measures'. However, this flexibility on compliance method has meant that countries have only achieved around a half of the energy savings obligation. The revised Energy Efficiency Directive, which was amended in 2018, includes an obligation for new energy savings over 2021-30 of 0.8% a year. If achieved, this would mark a continuation – rather than a ramp-up – in the current trend.

Policy makers have introduced a range of measures to encourage energy efficiency, including

- Targets on energy consumption
- Technical or performance standards on appliances
- Energy performance standards for appliances and new build
- Reduced tax rates for more efficient equipment
- Energy-saving obligations on energy suppliers
- White certificate schemes – these work like green or renewable energy certificate schemes but for energy efficiency
- 'Soft' policies such as information and awareness-raising campaigns, and mandatory energy audits for companies.

There are two key challenges impeding energy efficiency: the first is how to overcome the split incentive that arises with the tenant paying the energy bills and the landlord being responsible for the capital investment decisions. In such circumstances, the landlord may not be incentivized to implement potentially expensive works if the resulting benefits (eg, lower energy bills) will accrue to the tenant.

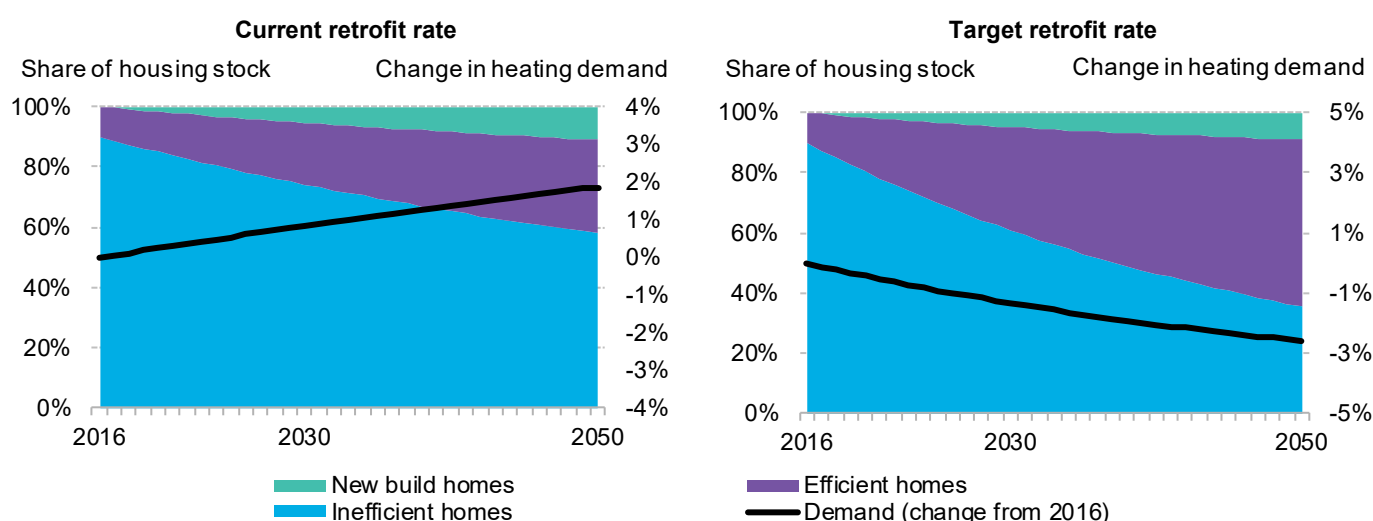
The second challenge concerns how to spur retrofits of existing buildings given the long payback periods. Slightly more than a third of buildings in the EU are over 50 years old and almost three-

quarters are energy-inefficient. The sector coupling pathway is based on an annual rate for retrofits of 1%. However, the rates of renovation of public and private buildings should be at least double this, according to the European Green Deal. Better building efficiency can also make the transition to low-carbon heating easier, for instance by allowing for smaller and cheaper heat pump units by reducing the overall heating demand.

BNEF analysis suggests that an annual retrofit rate of 2.4% in residential buildings (targeted by the EU) would increase the share of efficient homes in the EU housing stock by 24 percentage points by 2050 compared with the current retrofit rate (Figure 50). This in turn leads to a net reduction in heating demand in residential buildings of almost 3 percentage points compared to today's demand. However, the current retrofit rate is insufficient to drive a reduction in demand while the housing stock grows. To achieve these retrofit rates, the EU intends to encourage innovative financing mechanisms to channel private sector funding for energy efficiency.

Energy efficiency improvements for the housing stock are therefore likely to have a marginal impact on reducing total heating demand, without deep building retrofits beyond the scope of current EU targets. As a result, the expected volume of electricity demand for heating by 2050 with sector coupling is still significant, even in a scenario with double the retrofit rate of the housing stock from today's levels (for more, see Section 11).

Figure 50: Change in housing stock and energy consumption for homes heating demand by 2050



Source: BloombergNEF. Note: Data for 15 EU member states used for calculations. Assumes on average a 1% retrofit rate for the current scenario. New build rate is assumed to be 0.4% and a demolition rate of 0.2%.

The efficiency of the building stock may not have a substantial impact on reducing the scale of the heat demand challenge – but it does have a meaningful impact on the potential pool of buildings that can deliver demand-side flexibility in electrified heating demand in the sector coupling pathway. Prioritizing retrofits in homes that are most suitable for heat pump installations and other direct electric systems will therefore be an essential component of optimizing a power system in the period until 2050. But equally, prioritizing retrofits in homes that are highly inefficient and are less able to electrify or decarbonize from fossil-based heating systems in this timeframe will be an essential part of reducing building sector greenhouse gas emissions in the shorter term.

Section 11. Unlocking demand-side flexibility

Maximizing the volume of demand-side flexibility in the power system will be crucial to a successful sector coupling. Policy makers need to ensure the availability and uptake of flexible electricity tariffs, with strong incentives for all consumers to minimize net peak demand. As such, future tariffs will need to encourage users to shift consumption to times of renewables availability and to alleviate network constraints. Priority should also be given to the standardization and interoperability of the smart systems that are rolled out with sector coupling to provide the billing infrastructure for these tariffs.

This section outlines policy recommendations to resolve the potential problems due to sector coupling shown in the table below.

Table 11: Key power system problems

2	The growing share of variable generation in the mix makes it more difficult for the system operator to balance the market, and increases the need for short- and long-term flexibility.
3	Not all sources of flexibility (large-scale or distributed) are adequately valued and remunerated.
6	A power market needs to encourage technological innovation and ensure future-proofing.
8	Sector coupling will transform the demand profile by increasing and shifting the intraday and seasonal peaks. The scale of this challenge will depend on the volume of demand-side flexibility in the system.

Legend



Existing problem



New problem caused by sector coupling

11.1. Flexible tariffs

The way in which the cost of electricity is passed on to the end-user is a key challenge for sector coupling. To drive initial uptake of electrification and then sustain the flexible use of electricity across different consumer types in the long term, tariffs will need to be designed to give the right signal to the end-user, and accommodate the changing needs of the power system.

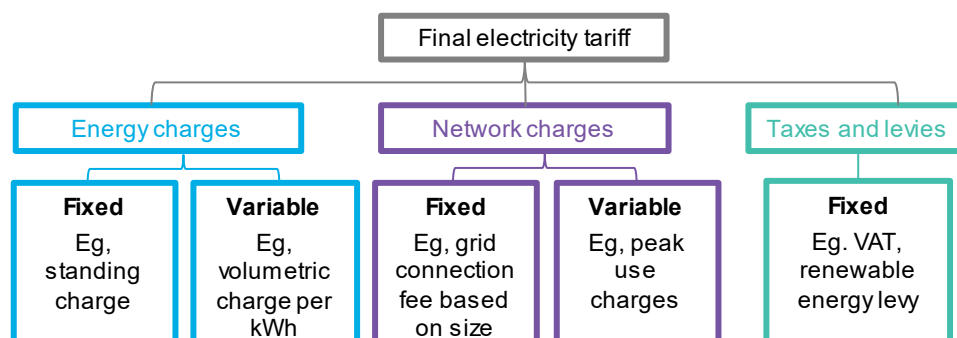
Tariff innovation is well underway in markets with accommodating regulatory environments, but consensus on the optimal tariff design to unlock flexible demand has not yet been reached. There is also still significant uncertainty over the extent to which wholesale price exposure should be passed on to the end-user to incentivize demand response, especially as power markets become more complex and potentially more volatile with the growth of variable renewable generation.

Recommendation:

Implement incentives to maximize use of flexible electricity tariffs

Electricity tariffs are split into three components (Figure 51), of which energy and network charges have both fixed and variable components. Here 'fixed' means the baseline fees that do not vary by kilowatt-hour usage. Variable, meanwhile, can be volumetric, where the rate is charged on a static kilowatt-hour basis, and time-varying volumetric, where the rate per kilowatt-hour is determined by the time of consumption.

Figure 51: Typical components of an electricity tariff



Source: BloombergNEF.

As discussed in Section 7, it will be cheaper and result in lower emissions if new loads added through sector coupling are more responsive to price signals, where it is cost-effective to do so. The benefits of more responsive demand include reduced pressure on the supply side to balance variable wind and solar generation, and therefore less additional firm and peaking capacity needs to be built. As a result, it will be important for retailers and policy makers to promote consumers' uptake of flexible tariffs.

Energy charges for flexible coupling

Recommendation:

Ensure flexible tariffs are available to all end-users

Table 12 breaks down the vast array of retail energy tariff structures into five broad types, of which time-of-use and dynamic pricing are classified as 'flexible' as they can incentivize demand response.

Table 12: Simplified overview of energy retail tariff types

Tariff type	Static pricing (fixed in advance)		Dynamic pricing (variable depending on market conditions)		
	Flat-fee	Time-of-use	Variable peak	Critical peak	Real-time*
Description	Energy price is fixed constantly	Energy price is fixed for set periods over the day, usually in three blocks: peak, mid-peak, and off-peak. These can also vary from winter to summer	Same as time-of-use, but price of peak block can vary based on system conditions	Consumer is alerted or incentivized (eg, awarded credit) to reduce demand at or ahead of a specific time	Energy price reflects wholesale electricity prices all the time, or during certain intervals
Flexible tariffs					
Illustrative tariff price over 24 hours (euros per kWh)					

Source: BloombergNEF. Note: * Also known as wholesale pass-through tariffs.

The EU internal electricity market directive legislated in 2019 mandates member states to ensure that all suppliers with a certain size of customer base offer a dynamic price contract,²⁵ although not all EU countries have transposed this requirement into national legislation.

Given the scale of demand-side flexibility required for a smooth sector coupling, governments should consider measures to promote flexible tariffs more strongly. For example, they could mandate retailers of all sizes to offer at least one dynamic tariff for each segment of consumers (residential, commercial and industrial). Any such mandate or policy should be designed carefully to ensure that retailers continue to have freedom to innovate and compete.

Recommendation:

Avoid being too prescriptive on dynamic tariff structures, to enable retailers to adapt to changing market and consumer needs

Retailers in most liberalized European countries already offer many tariff options with time-of-use or variable-peak pricing, giving end-users some exposure to price risk in order to incentivize load shifting to cheaper hours of the day and reduce peak load. However, policy makers could also encourage suppliers to roll out more innovative tariff structures tailored to the needs of sector coupling. For instance, several utilities, including E.ON, OVO, Scottish Power, and SSE Energy, have flexible tariffs for EV drivers in the U.K. SSE offers a static time-of-use tariff for EV drivers to charge their car for free between 12pm and 7am, when power prices are generally lowest in today's rates.

Flexible tariffs could help to minimize net peak demand and better integrate higher volumes of electrified building demand for heating, for example, by incentivizing thermal storage and load shifting as a source of demand-side flexibility. Tariff structures to unlock this would require more granular price signals, to encourage the conversion of electricity to heat in hours outside of peak demand or when renewables are producing.

Successful sector coupling will need consumers to switch to flexible tariffs – but also stay on them as the need for demand-side flexibility ratchets up toward 2050. Flexible tariff offerings by retailers will therefore need to be agile, to sustain consumer engagement and future-proof the flexibility of demand – that is, retain demand-side flexibility over time even as 'optimal' times of use shift and evolve.

Figure 52: Illustrative intraday wind and solar generation in Northern European archetype, 2050

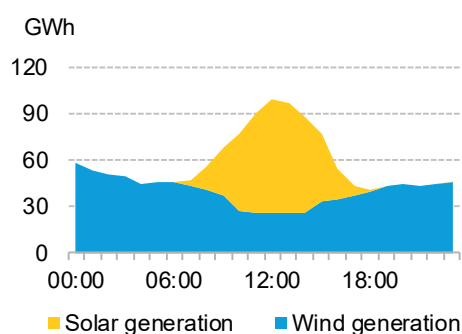
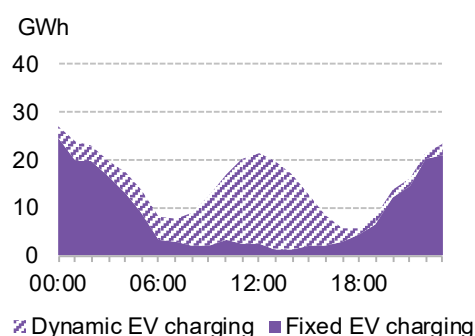


Figure 53: Illustrative intraday EV charging in Northern European archetype, 2050



Source: BloombergNEF.

25 The directive defines a dynamic electricity price contract as: "an electricity supply contract between a supplier and a final customer that reflects the price variation in the spot markets, including in the day-ahead and intraday markets, at intervals at least equal to the market settlement frequency"

This agility will be particularly important in some coupled sectors, such as transport. By 2050, the cheapest hour of generation in the Northern and Southern European archetypes alike is expected to be delivered by solar output (Figure 52). To ensure that dynamic EV charging and other coupled sectors, like flexible electrified heat demand, can take advantage of these hours of generation (Figure 53), adequate planning will be needed on the location, distribution and accessibility of infrastructure, like public EV chargers. Regulators must therefore ensure that the price signal is sufficiently passed on to incentivize the optimal use of electricity, even as the relevant time to do so shifts.

Consumer engagement

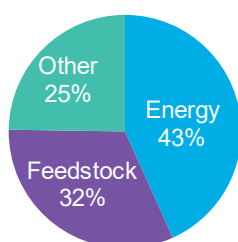
It will not be enough that tariffs are available to spur demand-side flexibility; consumers need to sign up and then stay on them. Most consumers today have limited engagement, and take-up of flexible tariff offerings has been very low. These offerings are anyway still contingent on the availability of smart meters and appliances.

Recommendation:

Consider measures to promote uptake of dynamic tariffs to drive consumer engagement

As such, policy makers should consider how to encourage uptake of dynamic tariffs over time as sector coupling proceeds, as well as improving price transparency and raising awareness. Sector coupling could create more opportunities to improve consumer engagement, particularly among households. Flexible tariff offerings for new demand sources, like EVs and heat pumps, might act as a sweetener to encourage consumers to become more active and engaged in their energy use as their electricity consumption ramps up. But given the myriad of electricity tariffs offered even by each retailer, policy makers could also take steps to improve consumers' understanding of pricing structures and the relative pros and cons. This could also offer opportunities for 'auto switchers' that offer the service of switching a consumer's tariff on their behalf.

Figure 54: Breakdown of steel producers' operating costs in Europe, 2019



Source: Bloomberg Intelligence, BloombergNEF.
Note: For blast furnace-basic oxygen furnace (BF-BOF) plants

Consumer engagement is generally better among large commercial and industrial end-users, but they may be more resistant to taking on additional wholesale price risk. For large companies, the energy component of a tariff is typically a flat-fee charge, often secured through a direct power purchase agreement (PPA)²⁶ with retailers. But energy costs on this basis can comprise a substantial share of operating costs. For instance, energy was 43% of total opex for European steel production in 2019 (Figure 54). Dynamic tariffs can therefore offer a way to reduce these costs, but only if the end-user is willing to operate more flexibly.

Network charges for flexible coupling

Electricity grid operators recoup their costs for building, maintaining and operating infrastructure through regulated network charges. These charges are typically based on the size of a customer's connection or their peak demand during critical times of the year.

Sector coupling introduces new considerations, increasing the need for these charges to accurately reflect network constraints. Constraints at both the transmission and distribution level are likely to occur with greater frequency or at different times of the day and year, as the power system changes with sector coupling. Rising demand also means grid reinforcement will likely be needed (and need to be paid for). For these reasons, the design of network charges can be another regulatory tool for supporting successful sector coupling.

Network charges can encourage demand-side flexibility, and are already widely used to manage peak demand. With sector coupling, grid operators and regulators are likely to retain variable network charges because of the substantial need for demand-side flexibility and constraint

26 Some heavy end-users are opting to secure corporate PPAs for renewable energy use.

Recommendation:

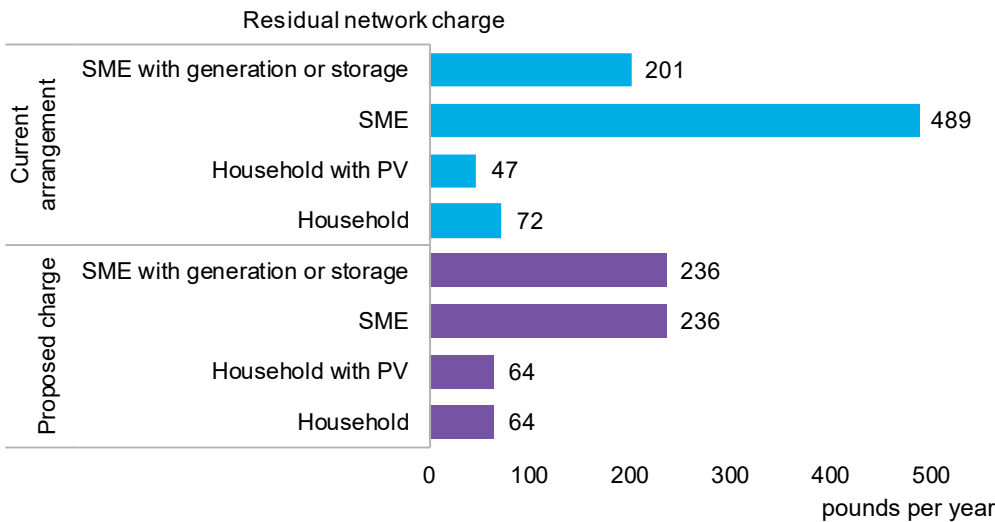
Ensure network charge structures deliver accurate signals to alleviate grid constraints and make best use of distributed energy resources

management, and to minimize the grid investment required due to sector coupling. Network charges will therefore need to work with dynamic energy pricing to shift demand to times that minimize system costs and network constraints.

Regulators could consider introducing more granularity into network charges, to better reflect the times of day and year when network constraints occur – as well as the locations in which they occur. These changes might also support system-level flexibility, as it is likely that local network constraints and system-level constraints occur at similar times. However, this is not a given – and better TSO-DSO cooperation will be needed to ensure that these differences are managed.

Our pathway also envisages an increase in behind-the-meter assets such as rooftop PV. Owners of such systems often pay less in network charges because they consume less electricity from the grid, even though they still benefit from the infrastructure for the hours when they are not self-generating. This results in lower revenues for grid operators, which increases the incentive to implement flat network charges only, meaning all end-users pay the same rate for grid access depending on their connection size and regardless of consumption. Alternatively the fixed proportion of network charges could be increased. In the U.K., residual network charges are being revised to ensure that those with behind-the-meter assets still contribute to grid costs (Figure 55). On the downside, the government has yet to announce measures to replace the lost revenue for behind-the-meter flexibility assets, creating more uncertainty and weakening investment signals.

Figure 55: Proposed changes to U.K. residual network charges



Source: Ofgem. Note: SME refers to small to medium enterprise, high energy consumption scenario. Residual charges form just one component of network fees in the U.K.

Overall, regulators need to ensure that the structure of network charges complement the market signals they wish to send via dynamic energy pricing. In principle, all consumers should have some exposure to variable network fees and variable energy charges. In a market with a substantial share of behind-the-meter generation assets, the fixed component of network charges could be larger for residential consumers (as these tend to have relatively low electricity demand). The variable component could then be bigger for large energy users as the charges would then help grid operators to incentivize flexibility in these loads.

11.2. Allocation of wholesale price risk and granularity of price signal

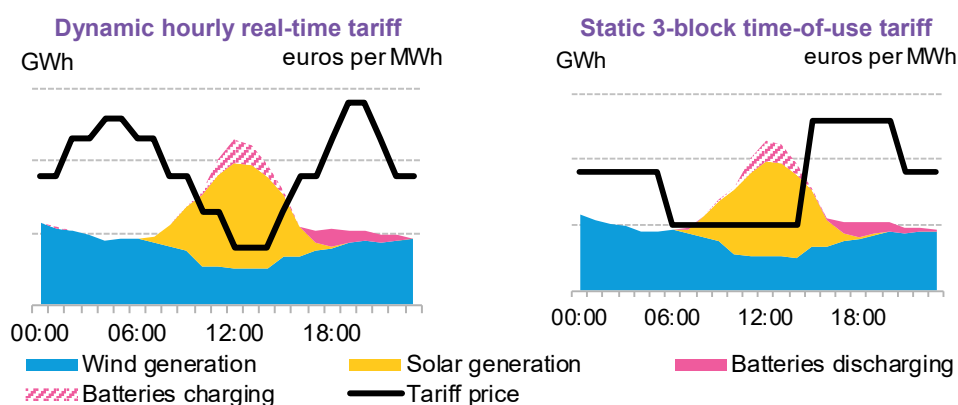
Recommendation:

Consider how to best protect vulnerable consumers

Different dynamic tariffs expose customers to different levels of wholesale power price risk. This is an important issue with sector coupling because wholesale prices are expected to become more volatile as more variable generation comes online. To give two examples: the variable energy component can be structured as a dynamic real-time tariff or a static block time-of-use tariff (Figure 56). These two options create two very different price profiles and risk profiles for the end user.

There is little consensus on the optimal granularity of price signals to instigate a demand response by the end user. Therefore regulators should aim to ensure that innovation, monitoring and evaluation of flexible tariff design enables retailers to react to the changing needs of the power sector. Retailers should also be able to adapt pricing granularly to balance between the allocation of risk and incentivizing flexible end-use.

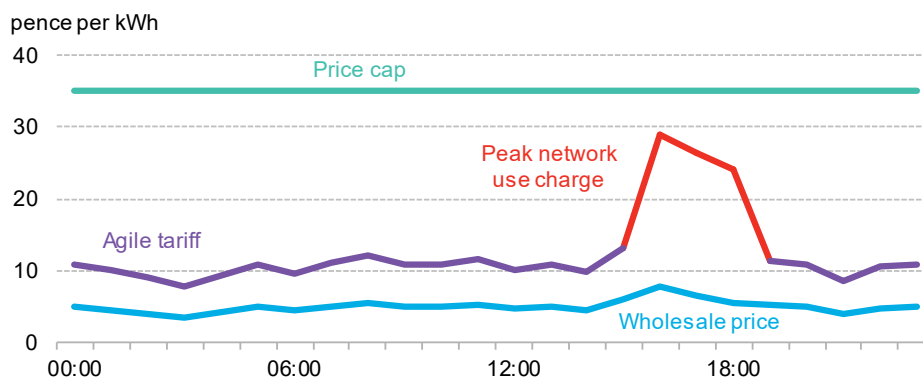
Figure 56: Illustrative flexible tariffs in 2050 with wind, solar and storage output



Source: BloombergNEF. Note: Tariff prices are illustrative only.

When considering how much wholesale risk to pass on to consumers, regulators must segment the customer base and pay particular attention to vulnerable users. A price cap could be implemented for vulnerable consumers, particularly to buffer against seasonal swings in electricity prices. In some markets, retailers introduce price caps to attract customers. Octopus Energy, for instance, launched a dynamic real-time tariff in 2019 for residential customers with a smart meter. This has a cap to limit exposure to price spikes (Figure 57).

However, regulators and policy makers will likely need to avoid dampening important signals to deal with the long-term flexibility gap. Seasonal power price variability is expected to become a more prominent feature of a future power system with sector coupling, and so some level of price exposure to this seasonal volatility may be necessary to incentivize the rollout of indirect electrification. For instance, buildings might opt for a hybrid electric and hydrogen heating system in the Northern European archetype, to optimize the balance between direct and indirect electrification of this sector.

Figure 57: Octopus Energy's 'Agile' tariff for U.K. residential customers

Source: Octopus Energy, BloombergNEF. Note: Agile tariff is a multiplier of the half-hourly day ahead wholesale power price to account for network charges and Octopus' own opex. Price spikes are managed by a 35p/kWh price cap. BloombergNEF clients may access: Company Profiles: New Residential Retail Models ([web](#) | [terminal](#)) for more.

11.3. Technological readiness

The availability and cost-competitiveness of appliances to deliver demand-side flexibility is also crucial to sector coupling. Such appliances include dynamic EV chargers, 'smart' heating systems, and smart meters or hubs that are able to operate together and flexibly with the power system. EV chargers and electric heating appliances demand special attention as they will create significant flexible demand if addressed properly.

Recommendation:

Standardize new appliances and roll out smart meters to provide the infrastructure needed for flexible coupling

The rollout of smart meters is already underway in most places. They will be crucial to unlocking flexible demand with sector coupling, as they provide the billing infrastructure needed for dynamic tariffs. In markets where smart meter penetration is still low (such as the U.K. and Germany), this will be a barrier to successful, flexible sector coupling.

In addition, priority should be given to the standardization of smart systems, particularly for highly distributed but large loads like EV chargers and electric heating appliances. These devices will need to be connected and digitalized, to be able to respond to price signals (and potentially other external signals too) in future. Given that the rollout of these appliances is already underway, policy makers should ensure that all new appliances are 'smart' and connected so that they can respond to market signals, and avoid being stranded.

11.4. Market access

Barriers to entry

Ensuring there are adequate flexible resources in place will not only be about implementing sufficient incentives – they also need a level playing field to compete. With that in mind, flexible technologies such as demand response and storage should be able to participate in the wholesale energy and ancillary service markets as well as any capacity mechanisms. Such an increase in potential revenue streams would better shield flexibility providers from policy and regulatory uncertainty.

Policy makers should also address other barriers that impede flexible resources' participation in such markets in practice. These include the following:

- **Germany:** limits on aggregation as well as stipulations on grid connection locations
- **The U.K.:** shorter contract lengths for some technologies (eg, demand response)
- **The Netherlands:** ban on independent aggregation, meaning suppliers control the access of flexible resources to the market.

Recommendation:

Create a level playing field for flexible resources to enable their full participation in the market

In general, performance requirements, 'shapes' of products and timing and frequency of bidding should be adjusted to create a level playing field for new flexibility sources.

These barriers may have arisen because the arrangements were set before the commercialization of newer flexible technologies such as batteries. Because the system seems to be working relatively well at present, there may be some resistance to changing arrangements, in particular from more traditional market players such as thermal generators.

The U.S. has made notable progress in this area for energy storage with the Federal Energy Regulatory Commission's (FERC) Order 841. This came into effect in May 2018, and covers six power markets. It required wholesale market rules to be changed to allow storage to take part in all services and the technology's physical and technical characteristics to be considered in market operations. The deadline to implement such changes is February 2020. This replicable framework entails reviewing the current framework for energy storage to participate in the wholesale market and understanding the barriers. Then the approach is to implement changes where necessary, specifically considering the particularities of energy storage.

Valuing new technologies

As well as enabling participation in all power markets, policy makers can introduce reforms to value more accurately the advantages of technologies like energy storage. Shorter dispatch intervals and settlement periods in the wholesale market would be one example (Section 14.2), while another would be ancillary service products that offer higher prices for a faster response: batteries can ramp up within milliseconds, compared with a few seconds for pumped-hydro plants, 10-20 minutes for aero-derivative open-cycle gas turbines (OCGTs) and 15-30 minutes for heavy-frame OCGTs.

Figure 58: National Grid frequency response services

Current			New		
Product	Response time	Duration	Product	Response time	Duration
Enhanced	1 sec	15 min	Dynamic moderation	1 sec	20 min
Firm primary & high	10 sec	20 sec	Dynamic containment	1 sec	20 min
Firm secondary	30 sec	30 min	Dynamic regulation	10 sec	Continuous
			Static containment	1 sec	20-30 min

Source: National Grid, BloombergNEF

National Grid in Great Britain, for example, is introducing faster frequency response services to replace the current firm products that were designed for conventional large power plants, and the 'enhanced frequency response' product to trial batteries (Figure 58). 'Dynamic' frequency response means that the scale of the response is proportional to the scale of the frequency

deviation. The new products will suit technologies like battery storage and demand response, although these markets will likely remain relatively modest in size at least for the foreseeable future. As a comparison, in Germany, the response time for frequency response reserves varies from 30 seconds to 15 minutes.

Recommendation:

Refine ancillary service products and arrangements to better reflect the value provided by flexible resources

Other reforms to the ancillary markets could strengthen the pricing signals for flexibility – for example, the frequency of ancillary service procurement could be increased. At present, ancillary services in many European countries, including the U.K. and Germany, are procured through tenders, mandatory agreements and bilateral contracts up to a year ahead of time. However, if procurement was undertaken more frequently, this should help participants to adjust the market segments they serve (eg, energy, capacity and ancillary services), as conditions vary – including changes in resources or demand. If the procurement occurred more frequently, prices could then be set for each period. This would enable investors to make more efficient decisions about how to allocate generation and storage capacity between market segments, and how to provide demand response. Better pricing information could then be used to improve penalties for non-delivery of ancillary services.

As explained in Section 6, the de-rating factors²⁷ allocated to renewables technologies will be crucial in determining the extent of their participation and their competitiveness. In 2017, the U.K. government issued new de-rating guidelines for batteries in the capacity market, reducing the factors for systems of all duration. This change effectively reduced the revenue of a one-hour storage system by 64%, for example, and as a result, less than 10% of the rated battery capacity cleared at the next auction.

²⁷ De-rated capacity is a plant's capacity discounted to account for unplanned contingencies. The de-rating factor is the share of nameplate capacity that generators may bid in a capacity market, for example. A 100MW plant with an 80% de-rating factor may bid 80MW.

Section 12. Making the best use of power networks

Policy support and regulatory changes are needed in order to ensure the electricity network is able to deal with the effects of sector coupling. Government and industry players should collaborate to tackle one of the biggest hurdles for increased electrification: public acceptance of grid extension. Options include awareness-raising campaigns together with compensation and other incentives for local communities. To reduce the volume of required grid investment, policy makers could implement more locational pricing signals and promote digitalization and interconnection. DSOs should also be incentivized to take a more active role in flexibility procurement at the local level, to facilitate a smooth sector coupling.

This section outlines policy recommendations to resolve the potential problems due to sector coupling shown in the table below.

Table 13: Key power system problems

5	The grid already faces challenges due to the geographic mismatch between the location of energy resources or generating capacity, and demand centers. Such challenges are set to worsen at a local level with the growth in ICT and other industrial clusters.
7	Sector coupling will substantially increase total electricity demand over the next 30 years even in markets where demand would otherwise flatten out or decline. This may be beneficial for some players in the electricity value chain, but will require investment and planning, particularly for the grid.
8	Sector coupling will transform the demand profile by increasing and shifting the intraday and seasonal peaks. The scale of this challenge will depend on the volume of demand-side flexibility in the system.

Legend  Existing problem  New problem caused by sector coupling

12.1. Network expansion and interconnection

Recommendation:

Implement incentives to boost public support of large network projects – eg, compensation or a project share to local communities

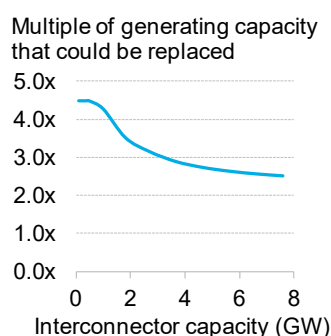
Sector coupling will require substantial investment in the expansion and reinforcement of the electricity network, both at the transmission and distribution level. The scale of this requirement is difficult to estimate due to the considerable uncertainties involved. Very rapid uptake of EVs and hybrid heat pumps in the U.K. could increase spending on distribution networks by up to 50 billion pounds by 2035 according to a report commissioned by the Committee on Climate Change.²⁸ While a substantial sum, this estimate assumes significantly faster deployment of EVs than assumed by the sector coupling pathway in Section 4 and it represents 4% of the total cost of the electricity system.

28 Vivid Economics and Imperial College, Accelerated Electrification and the GB Electricity System, commissioned by the U.K. Committee on Climate Change, 2019.

Recommendation:

Promote additional power market integration to reduce the required investment in the grid

Figure 59: Generating capacity that could be replaced by varying amounts of interconnection



Source: BloombergNEF, EU Power Weekly: *Interconnectors May Shrink* (available to clients at [web](#) | [terminal](#))

Boost public acceptance of grid build-out

Without policy intervention to boost public acceptance of large grid projects, network operators may not be able to keep up with growing power demand from sector coupling. Today such projects face considerable delays due to permitting issues and low public acceptance, to varying degrees across Europe. Of the large transmission-grid projects of common interest, 17% were delayed over 2017-18 and another fifth have been rescheduled. As a result, over half of TSOs' planned investment out to 2030 is expected to be made in underground or submarine cabling because of public opposition to large towers and overhead transmission lines. This has been a particular barrier in Germany, forcing developers to switch to underground cabling, which has sparked complaints from farmers. However, that country is not alone – similar opposition has been seen in other member states such as Ireland and the Netherlands.

As part of an awareness-raising campaign, policy makers could highlight the benefits to local citizens in terms of decarbonization or power prices – or perhaps that grid extension would be better than the alternative option that may be costlier and more invasive. They should also directly address concerns about damage to property values or the impact on the landscape or biodiversity. Government could also follow the example of countries like Denmark that have implemented community incentives to boost public support of wind farms (Section 10.3). For example, if a house value declines due to a nearby project, the operator must award compensation. In addition, a certain number of shares in the project must be offered to local residents and the community receives a direct allocation per megawatt of power generated.

Market integration

As discussed in Section 11, governments have the opportunity to reduce this grid investment need by incentivizing demand-side flexibility and switching to flexible tariffs. Another option is further power market integration because increased interconnection may substantially reduce the required volume of additional generating capacity. This is because electricity demand does not peak at the same time across Europe – due to factors such as different weather, time zones and cultural behavior. As a result, peak load in Europe is lower than the sum of the national peak loads. This difference may be up to 5%, based on BloombergNEF analysis published in December 2018 (Figure 59).²⁹ This means that if electricity were able to flow freely around the region, nearly 5% of the installed generating capacity would no longer be needed. Another way of looking at this is that perfect interconnection would boost capacity margins by 5%.

There is still an incremental benefit from every interconnector added. Our 2018 analysis suggested that that up to 7.5GW of interconnection could displace more than 19GW of generating capacity. This was a conservative estimate based on an analysis of networking demand alone. The impact of interconnection would be even greater when considering its impact on supply – eg reduction in curtailment, higher load factors.

12.2. Network optimization

Role of DSOs and retailers in local flexibility

Sector coupling will further increase the share of energy resources connected to the distribution grid (Section 8). This will require DNOs to accelerate their transition to DSOs and take on more responsibilities, including procurement of local flexibility services, which will be another way to

²⁹ BloombergNEF, EU Power Weekly: *Interconnectors May Shrink* (available to clients at [web](#) | [terminal](#))

reduce the required volume of grid investment. Energy retailers are also well-placed to incentivize and compensate end-users for investing in flexibility.

Recommendation:

Fund pilots for local flexibility markets and consider how to incentivize DSOs and energy retailers to take on more responsibilities

Local flexibility markets are at an early stage in Europe, with multiple models being tested. These tend to fall into three main categories, varying in regulatory and implementation complexity as well as opportunities for flexibility providers (Table 14). An integrated market platform offers several advantages over the other options by boosting transparency and price discovery, which should bolster competition and potentially investment. However, implementation would be more complex so it could be that these frameworks act as a continuum whereby DSOs begin by offering tenders and eventually an integrated market platform is created. Peer-to-peer (P2P) energy trading is another type of local energy market that is gaining popularity among utilities and the public. However, this model does not interact directly with distribution utilities or provide services to the grid.

Policy makers have an important role to play in supporting DSOs in this transition – not least by enabling and incentivizing flexibility providers to enter and participate in the local markets, as discussed in Section 13 and 14.2. The grid-connection process for flexible assets could be streamlined in some countries. Government could also finance pilot local markets similar to the U.K. government's \$5-million competition to fund trials of local flexibility exchanges. Other support could take the form of training DSO personnel or incentives to implement digital technologies (such as a dedicated budget in their investment plans).

Table 14: Frameworks for local flexibility procurement

Framework	How it works	Advantages	Disadvantages
Location-based tender	The DSO issues a tender for flexibility services in specific congested network areas, usually contracting from third-party aggregators, local generation or large loads.	Relatively simple process Allows DSO to design bespoke tenders for local needs	Providers may be limited to offering services to the distribution system and miss out on other revenue streams A complex patchwork of standards and rules may emerge if each DSO implements its own approach
Third-party market platform	A third party, either in conjunction with the DSO or independently, runs a marketplace for flexibility providers to trade energy and access grid services	Easier for aggregators to sell capacity across applications, and increases revenue streams Creates competition among market providers	Regulatory complexity may emerge within a region Needs coordinated procurement of services, or constraints may emerge
Integrated market platform	Third-party aggregators and flexibility providers have access to a centralized market platform. Energy is traded on this single platform for distribution, transmission and energy applications	In theory, should reduce grid costs Encourages data sharing and TSO-DSO collaboration Gives flexibility providers multiple revenue streams in one platform	Market implementation would be more complex Requires extensive cooperation among participants and product standardization

Source: BloombergNEF

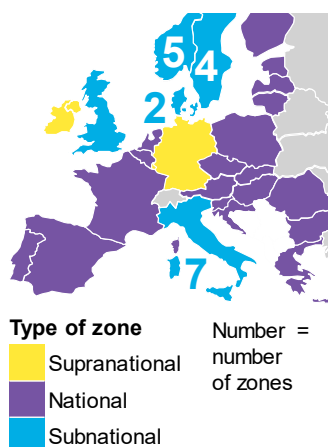
Further changes to DSOs' regulatory framework may also be needed because a significant issue relating to local flexibility markets is how they are funded outside one-off grants or trial projects. Under the traditional capex-plus regulatory system, network operators have no means of making a return unless it involves investing in capital projects, such as more network capacity. Various governments are seeking to address this issue with alternative regulatory options that aim to incentivize network operators to consider flexibility over network reinforcement. The following regulation options are being implemented in markets globally:

- **Capex-opex equalization:** capital and operational expenses are treated similarly, allowing network operators to select the lowest-cost option to reinforce the network. This allows flexibility services to be procured. The U.K.'s RIIO (revenue = incentives + innovation + outputs) framework is a prominent example of capex-opex equalization.
- **Non-wires alternative:** network operators are incentivized to use alternatives to building further network capacity and are allowed to retain a portion of the savings. Such frameworks are in place in California, Massachusetts and New York.
- **Innovation allowance:** regulators award funds to network operators to trial innovative approaches to operation, which may include flexibility. Innovation allowances are a feature of network regulation in Germany, the U.K. and Italy.

Locational signals

The consequences of increased power demand due to sector coupling will make it even more important that investment in the electricity network is made where it is most needed, and new sources of supply and demand site themselves with the grid's constraints in mind. One option for regulators and network operators is to strengthen locational pricing signals: for example, they could divide Europe's current bidding zones, which are the largest areas within which market participants may trade energy without transmission capacity allocation (Figure 60). Most correspond to national borders, and participants wishing to buy or sell electricity in a different zone have to take account of transmission constraints and potentially acquire grid capacity. In other words, grid congestion within a bidding zone is addressed separately from the wholesale market through redispatching or other measures.

Figure 60: Coverage of electricity bidding zones in the EU and Norway



Source: European Network of Transmission System Operators for Electricity (Entso-e), BloombergNEF.

However, there are indicators that current pricing arrangements in Europe are not effectively addressing grid congestion issues:

- The **low volume of available cross-zone capacity** indicates that congestion is found within – rather than between – zones. Over 2016-18, the margin of capacity available for cross-zonal trade was much lower than the target of 70% for most bidding-zone borders in the EU.
- **Congestion at bidding zone borders is mostly linked to intra-zonal network lines** rather than interconnectors: for example, more than half of the grid constraints in 2018 in the Central-West Europe region were due to internal lines.³⁰

The Agency for the Cooperation of Energy Regulators (ACER), TSOs and national regulators are working toward a bidding-zone review based on the Clean Energy Package, which was legislated in 2019. The outcome is scheduled to be announced in 2021.

Nodal pricing

A more granular system known as 'nodal' or 'locational marginal pricing' is used in electricity markets such as Ercot (Texas) and Caiso (California) in the U.S., and in Chile and New Zealand. This system is based on individual locational marginal price points (LMPs), known as 'nodes'. Each node represents a physical location on the transmission system (such as a substation) and its price incorporates the locational value of energy. Nodal pricing is meant to lead to more efficient dispatch, and lower redispatching costs. It also more accurately signals local grid constraints and better directs investment toward areas with high prices (ie, where demand is high and/or supply is scarce), potentially reducing retail tariffs.

³⁰ Central-West Europe comprises Austria, Belgium, France, Germany-Luxembourg and the Netherlands. Source: ACER, Annual Report on the Results of Monitoring the Internal Electricity Market in 2018, 2019.

On the down side, nodal pricing is more challenging to implement and operate than systems based on broader geographic areas, requiring sophisticated software and skills. The complex network topology in Europe would make it tricky to divide current bidding zones into smaller areas. Introducing nodal pricing across the region would require significant coordination and harmonization between organizations. There are concerns that nodal pricing or even smaller bidding zones could reduce market liquidity and potentially resulting competition issues due to frequent local scarcity. In the U.S., liquidity has been supported by the emergence of trading hubs based on a relatively stable average price across a set of nodes. End-consumer tariffs can be based on average nodal skills if the regulator is concerned about equity – ie, stopping exposing some users to higher local prices. In some cases, regulators have implemented price caps, thereby reducing the potential for differentials to arise.

Recommendation:

Strengthen locational pricing signals to ensure that the electricity network capacity – needed due to sector coupling – is built where it is most needed, and new sources of supply and demand taking of power grid constraints in siting decisions

Alternative mechanisms

Other types of locational investment incentive are:

- Variable grid-usage charges (eg, Great Britain, Sweden) or grid-connection fees (eg, many European countries)
- Location-specific capacity mechanisms (eg, PJM's capacity market in the U.S.)
- Location-specific support schemes for renewables (eg, Mexico's renewables auction scheme).

Policy makers could avoid worsening existing grid constraints or creating new problems by offering locational incentives to the newly coupled sectors. For example, they could offer subsidies or reduced tax rates to industrial companies willing to locate in clusters, together with energy resources such as hydrogen networks or CCUS facilities. This has been the thinking behind the U.K. government's Industrial Clusters Mission, which aims to create the first low-carbon industrial cluster by 2030 and the first net-zero one by 2040. See Section 13 for further discussion about siting hydrogen electrolyzers and the implications for the gas and electricity grids.

12.3. Data exchange and forecasting

Developing and commissioning new network capacity is a time-consuming process, making it necessary for grid operators to devise business plans well before the capacity is needed. Spending is regulated and locked in many years ahead of time. The potential uncertainties for electricity network planning due to sector coupling (Section 8) will make it even more difficult for network operators to devise robust business plans.

Better data transparency and collaboration

As sector coupling proceeds, grid operators will need access to more detailed and accurate consumption data and demand forecasts, for business planning. Currently, DSOs have no control over, and limited visibility of, the uptake of sector coupling appliances such as EVs and heat pumps, making it more difficult to plan investment. (This is also the case for the deployment of rooftop PV.) Moreover, TSOs largely rely on forecasts from the distribution grid operators.

While installers are meant to notify the grid operator when they connect an EV charger, this does not always happen in practice. In addition, there are other, more general challenges relating to data in the power sector such as inconsistency, sector fragmentation and historically a culture reluctant to share information.

Recommendation:

Strengthen data visibility and communication channels among grid operators, and with the newly coupled sectors

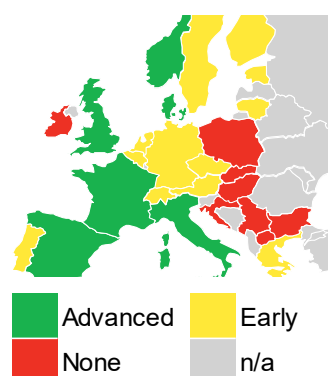
Therefore, policy makers or regulators need to strengthen data exchange among grid operators, and to consider new reporting requirements for the coupled sectors. For example, government could require EV charging and heat pump installers to notify the local grid operators at the time of connection. EV ownership could also be reported to DSOs at various times in the vehicle lifetime, such as when the vehicle is purchased, or at registration or inspection.

Fostering TSO-DSO collaboration

Sector coupling will make it all the more important for grid operators at the transmission and distribution levels to communicate effectively and cooperate with each other. Indeed, this will be required in order for DSOs to procure flexibility services on a substantial scale and therefore such collaboration should be promoted by policy makers and regulators, and taken into account in their performance evaluation. Entso-e and the European Distribution System Operators' Association (EDSO) are together working on frameworks to enable coordination.

In theory, a DSO could note a change in a customer's electricity consumption but this would require a smart meter to be installed, together with the relevant permissions. As explained in Section 11, smart meters should be rolled out universally and be interoperable.

Figure 61: TSO level of digitalization in Europe



Source: BloombergNEF, *Transmission Grids Go Digital with Data and Analytics* (available to clients at: [web](#) | [terminal](#))

Grid operators are beginning to discuss 'open' data practices – ie, based on the idea that certain data should be freely available, with collaboration at transmission level being led by Entso-e. Improving data visibility and promoting the use of open-source technology are also aims of the 'Energy Data Taskforce', set up to provide a set of recommendations to the U.K. government, Ofgem and industry.³¹ The recommendations have included a data catalog using standardized metadata of energy-system datasets, an asset register, and digitalization strategies. The French energy regulator had similar aims when it mandated sector players to contribute to the 'Open Data Reseaux Energies' tool, which contains datasets covering storage, network infrastructure and meteorology.

Better visibility of power infrastructure and assets will also help to unlock the flexibility market, reducing electricity system costs.

Digitalization

Employing digital technologies would be another way for network operators to reduce the investment need (and improve data visibility and demand forecasting). Few TSOs have formal digital strategies as yet, preferring to adopt such technologies to tackle a particular issue. Figure 61 illustrates the diverse level of digitalization adopted by TSOs across Europe, based on BloombergNEF's qualitative assessment. 'Advanced' denotes leaders that have published case studies and results of their efforts, while 'early' means sparse projects have been implemented. Some TSOs have set up internal teams to research and develop digital technologies, and are partnering with industrial equipment manufacturers and tech players, in particular cloud computing companies.

31 Energy Systems Catapult, *A Strategy for a Modern Digitalised Energy System: Energy Data Taskforce Report*, June 2019.

Section 13. Facilitating power-gas integration

Hydrogen and green gas (or ‘power-to-X’) play an important role in the sector coupling pathway, representing vectors for integration of the power and gas systems. But this integration will require policy attention. Good market design will be needed to ensure hydrogen electrolyzers are located optimally, accounting for the location of demand centers as well as gas and electricity network constraints. In addition, technical and legal barriers to hydrogen use in the gas grid will need to be addressed. Demonstration projects will help develop understanding of these, and awareness-raising initiatives will be needed to boost public acceptance of hydrogen heating – due to safety concerns and the eventual need for upgrade works.

This section outlines policy recommendations to resolve the potential problems due to sector coupling shown in the table below.

Table 15: Key power system problems

4	The increase in distributed energy resources on both demand and supply side creates challenges for grid management.
5	The grid already faces challenges due to the geographic mismatch between the location of energy resources or generating capacity, and demand centers. Such challenges are set to worsen at a local level with the growth in ICT and other industrial clusters.
9	An increase in the use of green hydrogen will raise the question of production location and transport, with repercussions for both the power and gas networks.

Legend  Existing problem  New problem caused by sector coupling

Power-gas collaboration

The increased integration of the power and gas markets will make it all the more important for these two sectors to work with each other. At regional level, the European Network of Transmission System Operators for Gas (Entsog) and Entso-e combined their long-term planning processes for the first time for the Ten-Year Network Development Plan published in 2018. The sectors also need to collaborate with all levels of government. For example, in some EU countries, local authorities have significant influence over building heating systems.

13.1. Hydrogen electrolyzer siting

In the early part of the sector coupling pathway, most green hydrogen continues to be produced on site or close to the point of consumption (eg, at or near industrial customers), on economic grounds. As hydrogen demand rises, and it starts being used in a wider variety of end-user types we see a growing need for transport by pipeline as the most cost-effective option. But without careful planning, the siting of electrolyzers could worsen, or create new, constraints on the power and gas networks, as discussed in Section 8.2.

Recommendation:

Finance detailed study into the optimal location for electrolyzers, taking account of the location of demand, the power and gas grids, and renewables resources

A green hydrogen producer may want to locate as close as possible to plentiful (or even excess) renewable resources to bring down its power expenditure. However, it should also build close to the source of demand – to minimize the need for hydrogen transport and thus defer any required changes to the gas grid. As a first step, government could fund a detailed study into the optimal locations for electrolyzers, taking account of the nearby gas and electricity grids as well as the location of demand and renewable energy resources. Incentives could also be offered for developers of the first pilot projects to choose those sites, in the same way as some governments are exploring the use of industrial clusters.

The energy regulator could ask the electricity and gas system operators to publish the data needed for private-sector investors to analyze optimal locations for electrolyzers, since this must account for the nearby gas and electricity grids as well as the location of demand and renewables resources. A streamlined permitting process – a significant challenge for large infrastructure projects – could be offered for these optimal sites.

Recommendation:

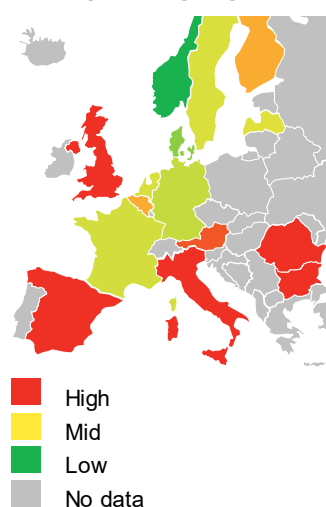
Support research and pilots regarding how to address technical and legal barriers to increase hydrogen usage

Alternatively (or in addition), locational electricity and gas network charges or other measures could be used to encourage producers to site the electrolyzers close to the abundant electrical supply and then use the gas grid (where possible) to transport the hydrogen to the demand. This could be an option in Germany, for example, where the electricity network would need considerable investment to transport large volumes of renewable electricity generated in the north to hydrogen electrolyzers and demand centers in the south.

The issue of where to locate hydrogen electrolyzers reinforces the need to create clear locational signals in energy pricing. The electricity and network charge elements of this are discussed in Section 11, but the same logic could also apply to gas prices and gas network charges.

13.2. Legal and technical barriers

Figure 62: Level of legal barriers for hydrogen relating to the gas grid



Source: HyLaw database, BloombergNEF.

Switching to 100% hydrogen would require physical modifications to the gas network and appliances, as outlined in Section 8.2. In the shorter term, injecting a blend of hydrogen would likely not require substantial upgrades, but a range of legal and technical barriers would need to be addressed. While the readiness of the gas network is not the focus of this document, known issues include safety requirements, permitting for connection and injection, and blending limits. In addition, payment and tariff arrangements should be adapted: adding hydrogen to the gas stream would change the calorific value of the gas and thereby the basis for delivering gas under contract. The Future Billing Methodology research project and industry consultation are considering how to bill for having two gases with different calorific values from the natural gas in the grid. Figure 62 illustrates the varying levels of legal barriers in European countries regarding injection of hydrogen into the gas network, based on the EU-funded HyLaw database.

As a first priority, government could fund (or otherwise instigate) a detailed study of the impact of injecting hydrogen into the network, and the required modifications for the gas infrastructure and appliances. This is likely to differ by country and potentially within sub-national regions. For example, the 25-million-pound Hy4Heat feasibility study, funded by the U.K. government, aims to establish if it is technically possible and safe to replace methane with hydrogen in commercial and residential buildings and gas appliances. Further research could identify the best zones of the gas grid for hydrogen injection, while the results of these studies should be shared within the sector. The government could also support early pilot and demonstration projects.

Actions to update and harmonize hydrogen concentration limits in the gas grid across the EU would help facilitate blending and create a hydrogen market. The EU should then take the lead in

raising blending limits toward 100% hydrogen. The current patchwork of limits causes fragmentation of the gas market and can prevent cross-border flows. Various organizations in Europe are assessing standards (eg, HyReady and HIPS-Net), as is the European Commission, which is also considering the role of green gas in the natural gas grid. These limits should be set early so that compatible appliances can be developed and acquired by consumers. Once blending limits have been harmonized, the EU should take the lead in raising them.

Another issue potentially requiring coordination at EU level concerns whether power-to-gas assets should be “market-driven private production facilities” or as infrastructure owned by system operators. Such assets would include electrolyzers connected to the electricity grid or to a renewable power plant from which to draw electricity to produce hydrogen. Entso-e suggests that a regulated environment could help to develop the power-to-gas assets “especially in the start-up phase”, according to its 2019 position paper.³²

Recommendation:

Harmonize and then raise hydrogen blending limits and address ownership constraints of power-to-gas assets

However, allowing grid operators to own power-to-gas assets would be out of line with EU energy unbundling law, which separates supply and generation from operation of the networks. It could also prevent market entry and hinder competition because TSOs and DSOs in Europe benefit from a low-risk environment and guaranteed revenue streams. Non-discriminatory access to the grid could put at risk competition in the market and incentives for innovation would be weaker, potentially resulting in less power-to-gas investment. This question of ownership has arisen in recent years relating to energy storage. These projects were eventually classified as generation assets that may not be owned or operated by TSOs and DSOs. One way forward therefore could be to see how the first pilot and demonstration power-to-gas assets operate in the market.

13.3. Public acceptance of hydrogen

Recommendation:

Fund large-scale project to demonstrate the safety of the full hydrogen process chain from end to end

Sector coupling has the potential to incite public opposition in two main ways: projects to upgrade the electricity network (Section 12) and safety concerns around hydrogen. In the latter case, hydrogen use in residential buildings is likely to be of particular public concern, and this will be needed for at least some heating appliances, in the latter half of our sector coupling pathway. The replacement of heating appliances with hydrogen-compatible ones could be delayed by such public concerns, particularly given the known difficulties associated with entering individual homes to install, replace or modify appliances. Awareness-raising campaigns should begin well before work begins, highlighting why low-carbon heating is required, and incentives could be offered to early switchers.

In addition, while biogas and biomethane pose no greater risk than natural gas, the safety case for blending hydrogen has yet to be fully demonstrated. Government therefore should support large-scale projects that tackle this challenge. One example is HyDeploy in the U.K.: this is on course to be the first live demonstration of hydrogen in homes, and aims to prove that blending up to a 20% threshold is safe. The Health and Safety Executive gave the go-ahead in autumn 2019 for the 10-month live pilot of blended hydrogen on part of the private gas network.

Other such projects are underway: a consortium led by French utility Engie is leading a consortium for the GRHYD demonstration project: its aim is to trial 6-20% hydrogen injection into a gas distribution network comprising a residential neighbourhood of some 200 new homes and a natural-gas-vehicle refueling station for buses. Other projects have been undertaken in Germany and the Netherlands.

32 Entso-e, Position on Sector Coupling through Power to Gas and Sector Integration, Oct. 2019.

Section 14. Strengthening investment signals for generation and flexibility

Recommendation:

Implement measures to give renewables developers more revenue certainty and ensure sector coupling does not result in higher emissions due to capacity mechanisms

Policy makers will likely have to implement additional revenue streams for renewables on top of any capacity mechanisms because wind and solar often cannot participate in such schemes, or they face significant barriers. Otherwise, sector coupling may result in additional fossil-fuel build, leading to higher emissions. Options include incentives for the newly coupled sectors to sign corporate PPAs to reduce exposure to whole power price fluctuations, or a long-term program of auctions to award subsidy-free contracts for difference. Policy makers will also have to address the missing money for flexible technologies, or there will be insufficient resources to accompany the ramp-up in variable generation.

This section outlines policy recommendations to resolve the potential problems due to sector coupling shown in the table below.

Table 16: Key power system problems

1	The power sector may fail to deliver a clean and reliable supply of electricity because the wholesale market does not offer credible signals for investment in renewable and dispatchable capacity. This is the 'missing money' problem.
3	Not all sources of flexibility (large-scale or distributed) are adequately valued and remunerated.
7	Sector coupling will substantially increase total electricity demand over the next 30 years even in markets where demand would otherwise flatten out or decline. This may be beneficial for some players in the electricity value chain but will require investment and planning, particularly for the grid

Legend

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 Existing problem

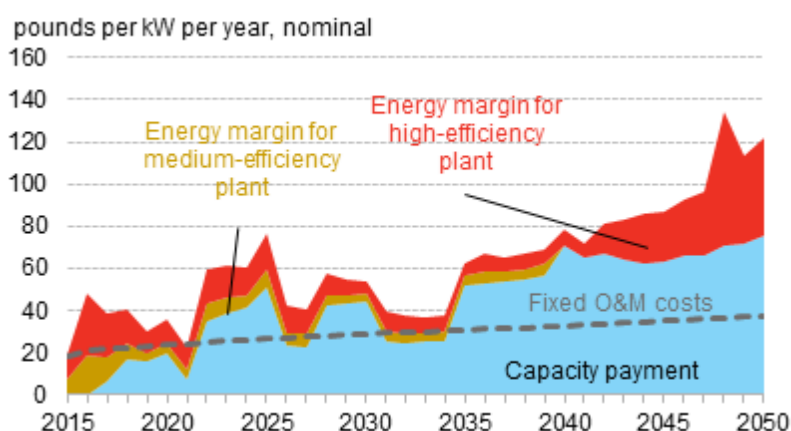
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 New problem caused by sector coupling

14.1. Investment signals for generation

Careful use of capacity mechanisms

Capacity mechanisms – in addition to or even in place of the wholesale market – are likely to play an increasing role in generators' cash inflows in Europe. Governments favor such programs as a way to ensure security of supply, while they mitigate the missing money problem for fossil-fueled plants by creating an additional revenue stream. Indeed, a medium-efficiency CCGT plant in the U.K. will earn 91% of its revenue over 2015-50 through the capacity market, according to BloombergNEF analysis (Figure 63).

Figure 63: Revenue streams for a CCGT plant, U.K.

Source: BloombergNEF. Note: 'Energy margin' = power market revenue minus operational costs directly related to generating that energy.

However, capacity mechanisms are unlikely to solve the missing money problem for renewables because they have historically favored firm generation and kept online dirtier or less efficient power plants. The EU internal electricity market regulation passed in 2018 will help to address this problem by only allowing member states to introduce capacity mechanisms under certain conditions – in particular, new power plants may not participate if they emit over 550g CO₂/kWh.

Recommendation:

Implement measures to give renewables developers more revenue certainty and ensure sector coupling does not result in higher emissions due to capacity mechanisms

To avoid sector coupling resulting in increased fossil-fueled build, policy makers could open the capacity mechanism to wind and solar plants, which may only take part fully in some of the 14 schemes across the EU. Even in those schemes, the de-rating factors³³ or other conditions mean that variable generation technologies are unlikely to benefit significantly. Wind and PV plants may already compete in these markets in the U.S. But the high concentration of these technologies is beginning to erode the value of their capacity – a trend we expect to continue.

Ensuring wind and solar build

For these reasons, an additional program may be needed on top of a capacity market or reserve, to ensure continued deployment of wind and solar. One option would be renewables portfolio standards, which have been a key driver of clean energy deployment in many U.S. states by providing a stable source of demand. These programs require electricity suppliers (which are typically regulated utilities in the U.S.) to supply a minimum share or amount of their load with eligible renewable energy sources.

It might be simpler to implement a supplier obligation with both reliable and clean components: this would be similar to the original design of Australia's National Energy Guarantee as it was proposed in 2017.³⁴ The emission requirement would have obliged retailers to ensure that the average emission intensity of their electricity procurement fell within a certain limit, while the reliability requirement would have been a graduated process to encourage, and then require, retailers to cover their peak load with contracts. The benefit of a supplier obligation relative to a

³³ De-rated capacity is a plant's capacity discounted to account for unplanned contingencies. The de-rating factor is the share of nameplate capacity that generators may bid in a capacity market, for example. A 100MW plant with an 80% de-rating factor may bid 80MW.

³⁴ The full National Energy Guarantee did not survive Australia's heated climate politics but one part – the Retailer Reliability Obligation – began in July 2019.

capacity market is because retailers directly own customer relationships and are therefore in the best position to influence consumer behavior. However, it may deter market entry and reduce competition.

Other options to be implemented in place of, or addition to, a capacity mechanism include an auction system where generators compete for long-term contracts or contracts for variable technologies. Winning projects could be awarded a 'subsidy-free' contract for difference (CfD).³⁵ In this context, a subsidy-free CfD (Figure 3) would be similar to a 'regular' CfD (Figure 4) such as that implemented in the U.K.: the contracts would be awarded in a pay-as-clear auction; but the agreed strike price (fixed price payment) would have to be below a reference price.³⁶ Generally, this value is taken to be the forecast wholesale power price over the CfD lifetime; but there are other candidates.

Auction systems exist today in many European countries, but there is a growing trend toward merchant renewables, or auction bids that expose the investor to high levels of merchant risk. This is unlikely to be sustainable in the long term, in a world where sector coupling takes place and the power system is dominated by renewables.

Figure 64: 'Regular' CfD

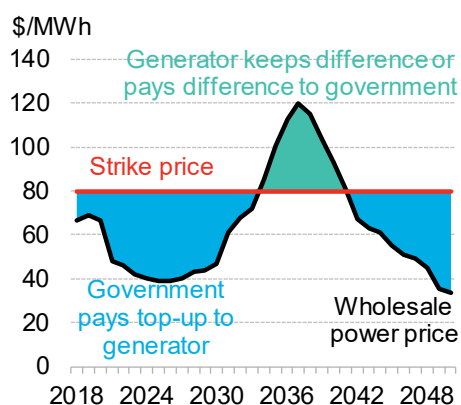
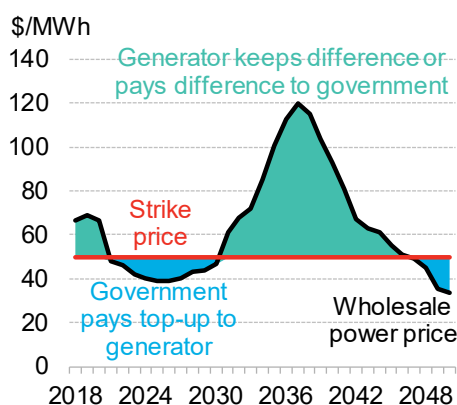


Figure 65: 'Subsidy-free' CfD



Source: BloombergNEF

Opportunities for power purchase agreements

Long-term power purchase agreements with large consumers could also provide revenue certainty for renewables investors. With electricity comprising a growing share of their operating costs, companies in the newly coupled sectors – in particular buildings and industry – will be more motivated to reduce their exposure to wholesale power price fluctuations by signing such contracts. These agreements help to mitigate the missing money problem but may become less attractive to the customer as wholesale electricity prices decline.

Such deals have become increasingly popular in Europe as governments have begun to phase out renewables subsidies, with technology players and manufacturers leading the way. Of the 6.4GW of subsidy-free PV projects due to come online in Europe by end-2020, over 85% had

³⁵ This does not necessarily mean no financial payment from government to renewables project for power generation (BNEF's definition of a 'subsidy'). Rather, it means that no such payment is expected – based on current forecasts of, say, the wholesale power price. Alternatively it could mean that the government would be in a neutral net cost position, taking account of all payment in- and outflows over the renewables project lifetime.

³⁶ Currently in the U.K. program, bids must be below technology-specific 'administrative strike prices' set by the government.

already signed a PPA at the time of writing, according to BloombergNEF analysis. Indeed, most banks consider such deals a prerequisite to offering cheap, long-term debt financing.

Policy makers could help to incentivize utility and corporate PPAs through:

- **Targets:** several countries have introduced renewable portfolio standards on retailers and large power consumers (eg, Mexico, China, India and Australia)
- **Sustainability transparency requirements:** an example is the EU's Non-Financial Reporting Directive, which requires certain companies to disclose their environmental protection policies.
- **Risk-mitigation tools:** for example, Norway's export-credit agency (GIEK) offers PPA guarantees to industrial companies to mitigate counterparty risk.
- **Tax incentives:** for example, Canada offers a tax write-off for corporate clean energy procurement.

14.2. Revenue certainty for flexible resources

As well as generation technologies, policy makers should address the missing money problem for flexible resources such as storage and demand response (Section 7.4). Without these measures, there is a risk that there will be insufficient flexible capacity to mitigate the increased variable generation brought online due to sector coupling. Capacity mechanisms may provide another revenue stream (see above) but they are not always open to flexible technologies (Section 11.1). This section outlines other options.

Changes to wholesale markets

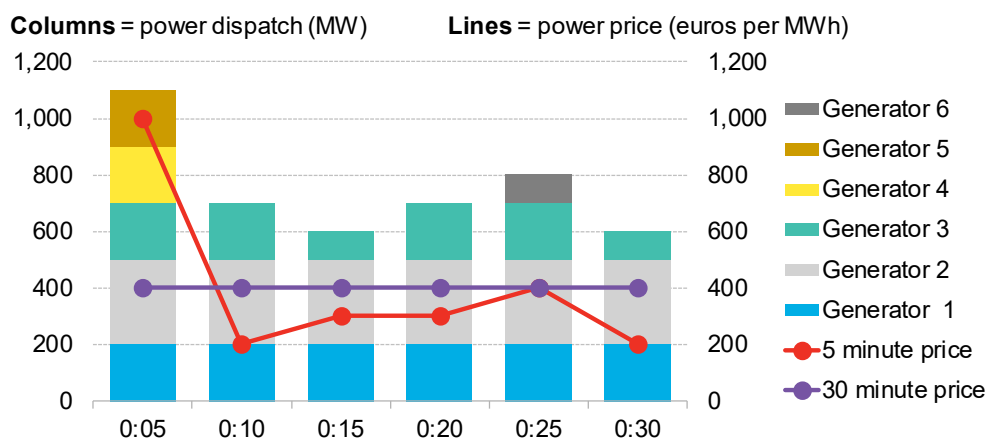
Recommendation:
 Strengthen pricing signals for flexible resources through shorter dispatch intervals and financial settlement periods, and moving gate closure nearer to real time

Flexible resources play a crucial role in a successful sector coupling. But wholesale power markets do not effectively reflect their value in particular in terms of quicker response times (Section 7). Policy makers and regulators could improve the pricing signals by reducing and aligning dispatch intervals and financial settlement periods, and shifting gate closure closer to the real-time delivery of power.

Dispatch intervals are the period for which physical delivery of electricity is traded on the market. Most products traded in the European day-ahead and intraday wholesale markets are hourly, although some countries are shortening dispatch intervals. Shorter intervals would better value flexibility by rewarding market participants that can adjust production or consumption quickly in response to changing market conditions. In any case, EU member states will have to reduce to 15-minute intervals by 2021 based on the internal electricity market directive passed in 2018.³⁷

Generally, physical dispatch and financial settlement periods are aligned; but sometimes the latter is longer due to historical reasons such as a lack of technology for metering and data processing when a market was created. In a set-up where settlement is every half hour while dispatch is 5 minutes, the settlement price is the average of the dispatch price of the previous six five-minute intervals. This tends to be the case in Europe: in Great Britain, settlements occur every half-hour, and it occurs every 15 minutes in Germany. In 2021, Australia's National Electricity Market (NEM) will switch from 30 to 5 minutes.

³⁷ Participants must be able to trade in intervals at least as short as the imbalance settlement period, which must be 15 minutes by 2021, unless the regulator has a derogation.

Figure 66: Illustrative example of 30-minute vs 5-minute financial settlement periods

Source: BloombergNEF

A longer settlement period means that the physical power system (which matches supply and demand) is not aligned with the price signal provided by the market for that period. For example, the purple line in Figure 66 represents the spot price that all generators would get for dispatching power in that 30-minute interval. The red line represents dynamic spot prices that generators would receive under a five-minute settlement rule. This set-up does not effectively discriminate between fast and slow response, resulting in inappropriate compensation of generation assets that provide delayed response up to 25 minutes after the physical system needed it. For example, in Figure 68, 'Generator 6' would receive the same price for power as the other generators even though it did not dispatch when the system needed it most (in the first dispatch interval).

The average spot price may therefore be below the price a fast responder such as a storage asset would be willing to offer for providing supply for a shorter period (eg, 5 or 10 minutes). Likewise a large energy user such as an aluminum smelter may be willing to curtail its electricity consumption for a short period but not for the full 30 minutes – without affecting its operations.

A shorter financial settlement period in line with the dispatch interval should strengthen the business case for technologies capable of providing faster response such as grid-scale batteries and advanced gas peaker plants. In addition, retailers may be spurred to unlock vast behind-the-meter resources such as dynamic EV charging, demand response and batteries, through aggregation. More efficient and faster response in the wholesale energy market would also mean less reliance on ancillary services to correct imbalances.

Recommendation:

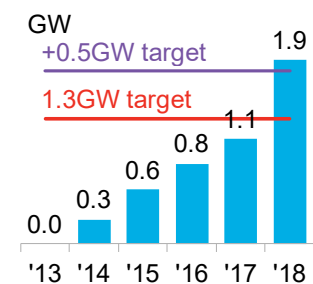
Support other sources of revenue certainty for flexibility providers – eg, capacity markets

Australia's NEM has four years to transition to the new settlement regime, which will require IT system alterations, some contracting changes, and the installation of new metering devices by generators and the market operator. A transition period of such a duration would allow enough time for hedging contracts to expire and for new generation assets to be built.

Mandates

There are various ways in which governments can bolster the investment signals for flexible resources outside the power markets: policy makers could implement incentives to promote technologies such as storage and demand response – in the same way as feed-in tariffs, auctions and renewable portfolio standards have been used to kickstart the rollout of wind and solar power. Targets can also be very useful in encouraging utilities to invest in energy storage. In the case of

Figure 67: Cumulative energy storage capacity procured by California IOUs relative to target



Source: BloombergNEF.

California, a target was imposed in 2013 on the three investor-owned utilities (IOUs)³⁸ to procure on aggregate 1.3GW of storage capacity by 2020 (AB 2514).

State regulators added a goal of 500MW of distribution-connected or behind-the-meter storage (AB 2868), and utilities were required to analyze the potential for long-duration storage. This took the total mandated capacity to just over 1.8GW. By end-2018, nearly 2GW of storage projects had been procured. These installations must come online by end-2024. The California Public Utilities Commission now envisions a lot of low-cost solar build supported by 11-19GW of battery storage by 2030, according to the preliminary version of its resource plan released in November 2019. The new storage results far exceed the CPUC's stated energy storage mandates. The mandates encouraged utilities to dedicate resources to better understand energy storage, as well as allowing them to be remunerated for their investments.

Renewables 'firming' obligations

Another effective way to spur flexibility deployment is firming requirements for renewable energy – essentially, policies that require renewable generators to manage their output in prescribed ways, typically by co-locating an energy storage asset. Utilities in the remote regions of Japan – Hokkaido and Okinawa, for instance – only grant grid-connection approval to renewables projects if storage is also installed for ramping. Storage can help wind and solar generators by delivering power to the grid in accordance with ramp-rate requirements, in times when the variation of the output would be greater than the ramp-rate requirement.

Alternatively, wind and solar developers could be required to install or procure equivalent flexible capacity – whether as a pre-condition of government subsidies or project permits. Most examples to date have occurred outside Europe – eg, Madagascar, Australia, South Korea and India. For example, Shandong province in China released a policy in August 2019 giving renewables developers easier access to a grid connection if they install battery storage with new solar assets. Germany's 'innovative' auctions are designed to encourage renewables-plus-storage projects, but this is not a requirement. Such measures have been relatively rare to date, not least because they tend to make the associated renewables project less profitable. However, if implemented, firming requirements would force renewables developers to co-locate projects with storage assets, helping to make the technology mainstream.

Decarbonization efforts

Energy storage and demand response would also benefit from policy mechanisms that dent the competitiveness of coal and gas generators. Such mechanisms increase the deployment of variable wind and solar, while certain types of gas plant can be used for peaking. Even long-term zero-emission targets impact the financial projections for a fossil-fuel-fired power plant built in the next couple of years. For example, the U.K. has committed to reach net-zero emissions by 2050. This means that a CCGT would need to be commissioned by 2025 to operate for a 25-year lifetime, assuming it is the last plant to shut down (or else it must be mitigated with CCS or negative emissions elsewhere). If it would have a shorter lifetime, or lower utilization, than that commonly assumed for these assets, this could benefit flexibility uptake as an alternative.

³⁸ San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E) and Southern California Edison (SCE).

Appendices

Appendix A. Sector coupling pathway – in detail

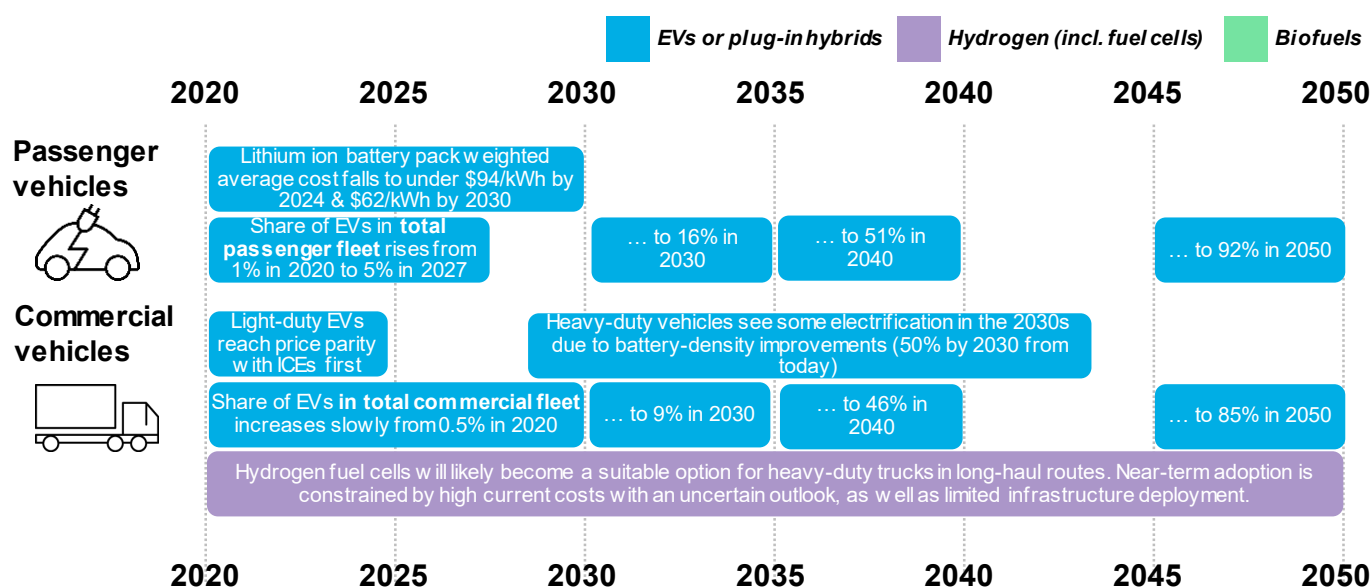
A.1. Transport

Road vehicles

The current fleet of road vehicles remains dominated by fossil fuels – nearly evenly split between diesel and gasoline. However, sales of EVs in the Northern European archetype have risen by a compound annual growth rate of 37% over the last five years. And the pathway shows this trend continuing, driven by government subsidies, tightening fuel-economy regulation, increased model availability and rising concern over urban air quality. Battery-only EVs (BEVs) reach price parity with internal combustion engine (ICE) vehicles over 2022-26, according to BloombergNEF forecasts. The pathway shows EVs accounting for 2% of sales in 2020, rising to 43% a decade later, and 100% by 2040 due to the ban on the sale of ICE passenger vehicles. By 2050, most passenger cars have been replaced with EVs, which comprise over 90% of the fleet.

Commercial road vehicles begin to electrify in the 2020s, but progress varies by weight class and duty cycle (Figure 68). We have segmented the commercial market along these two dimensions. Light-duty electric vans and trucks are first to reach cost parity with ICE vehicles, and the uptake of electrification for city and suburban applications will be dominated by battery EVs. In the medium-duty segment (Figure 69), range-extender (REX) or plug-in hybrid EVs (PHEVs) will be adopted first as their total costs can be as low as those of a diesel vehicle. However, low model availability will constrain initial uptake.

Figure 68: Sector coupling pathway for the Northern European archetype – road transport











Source: BloombergNEF

Heavy-duty vehicles and long-haul applications will be harder to electrify due to weight and range constraints. Battery density improvements and relatively good economics mean that electrification plays a role for heavy commercial vehicles in urban and suburban duty cycles from the late 2030s. Hydrogen may be a suitable fuel for heavy-duty trucks on long-haul routes but its near-

term adoption will be restricted by high costs and limited infrastructure. But the benefits of the technology and potential for fueling station build-out on specific routes will spur some deployment in the heavy-duty segment of the commercial market.

Figure 69: Trucking market by segment

		Use (guide annual miles)			
		Urban <30,000 miles	Regional 30-100,000 miles	Long-haul >100,000 miles	
Guide weight	Heavy >15 tons	Refuse, construction 	Drayage, distribution 	Freight 	Heavy and long-haul segment
	Medium 3.5-15 tons	Distribution 	Distribution 	Freight, distribution 	
	Light ≤3.5 tons	Last-mile distribution 	Distribution 	Light and urban segment	

Source: BloombergNEF

As a result of these trends, the share of EVs in sales of all commercial vehicles will rise slowly, from 1% in 2020 to slightly more than a fifth in 2030 to over 70% in 2050. The cost competitiveness of EVs as well as bioenergy feedstock supply and sustainability concerns constrain the use of biofuels for road transport in Europe, reducing its share of the fleet from 10% in 2020 to 3-4% by 2050, both for passenger cars and light & urban commercial vehicles.

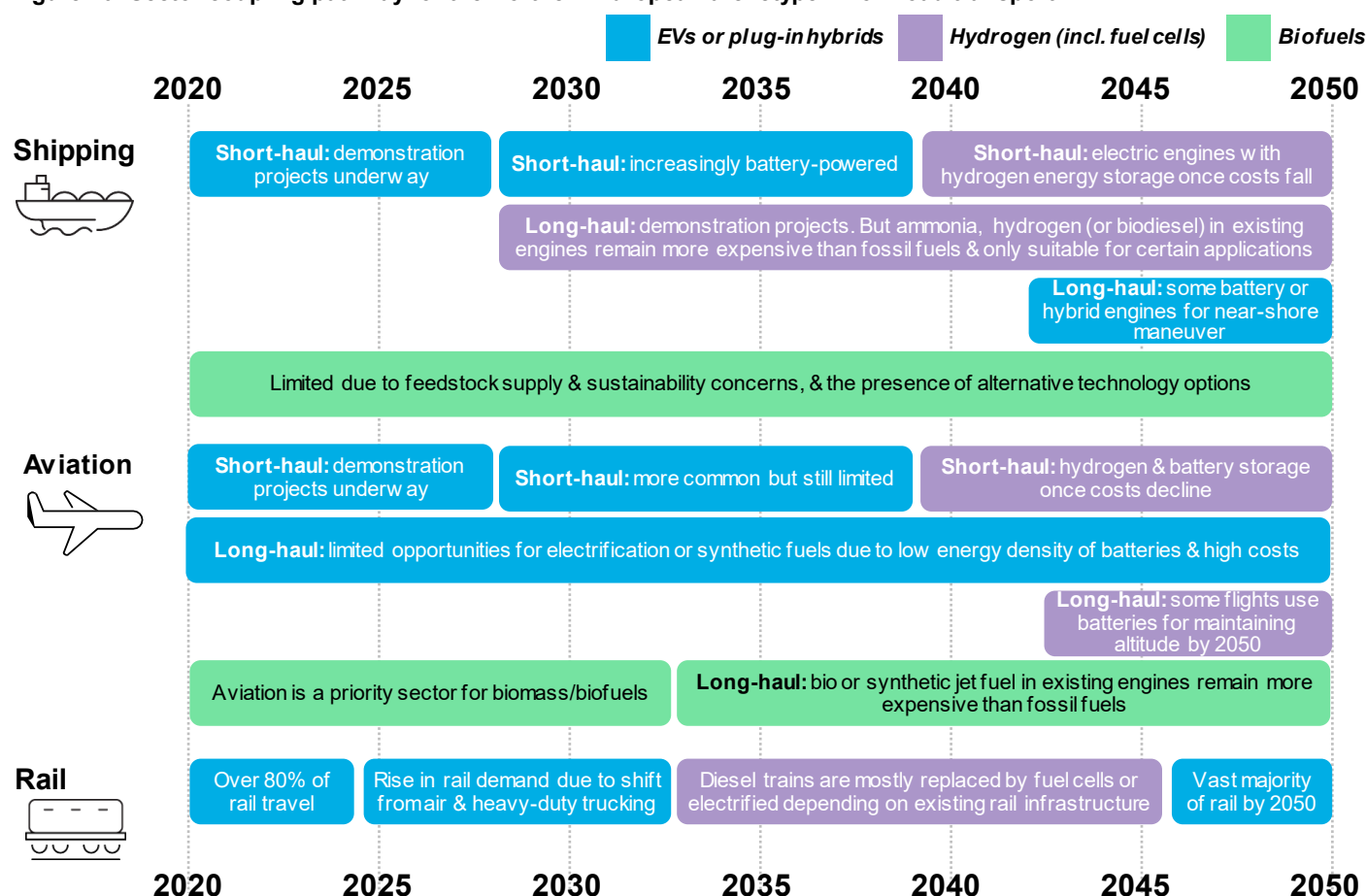
Municipal buses (which are included in 'commercial road vehicles' in this report) go electric more quickly than any other segment of road transport, according to BloombergNEF, with the drivers being improving economics and concern about the impact of emissions in urban areas. Europe remains the second-biggest market for municipal e-buses (after China) over the medium term. The EU's revised Clean Vehicles Directive and cities' commitments as part of the C40 Cities Fossil-Fuel-Free Streets Declaration will mean that over 6% of the fleet will be electric by end-2025.³⁹ Fleet penetration reaches some 80% by 2040.

Non-road vehicles

The pathway for shipping and aviation depends on the journey distance: we expect decreasing battery costs and further density improvements to increase the use of electricity for short-haul transport such as domestic flights and the coastal, river and inland waterway markets (Figure 70). Several electric ferries already operate in Europe and the prototype of the first commercial all-electric passenger aircraft was launched in 2019. However, even as feasible range grows, the use of electricity in shipping and aviation is limited on the grounds of cost and length of asset lives.

³⁹ At the time of writing, 17 cities in Europe had signed the [C40 Cities Fossil-Fuel-Free Streets Declaration](#) to procure only zero-emission public buses from 2025.

Figure 70: Sector coupling pathway for the Northern European archetype – non-road transport



Source: BloombergNEF.

For long-haul journeys, low battery energy density and hydrogen volumetric density, together with cost disadvantages, constrain the potential for direct electrification and hydrogen via electrolysis. Near the end of the period, some long-haul ships may switch to battery or hybrid engines for near-shore manoeuvre, especially as some ports have implemented air pollution controls. Similarly, some planes could use batteries for maintaining altitude.

Instead of electrification, these sectors see some growth from 2040 in the use of fuels that can be 'dropped into' existing engines because of their technical feasibility and the long asset life of planes and shipping vessels. Ammonia is expected to be favored for shipping over biodiesel due to sustainability concerns and over direct hydrogen use due to lower volume and storage concerns. Demonstration projects are rolled out although the use of ammonia remains more expensive than fossil fuels and only used for certain applications (eg, freight rather than passenger transport).

Aviation is expected to be one of the few sectors where the use of bioenergy resources grows (to a limited extent) over the next 30 years, because of the lack of available decarbonization options. The pathway does not assume that the Northern European archetype implements policies to reach net-zero emissions and therefore the use of drop-in bio or synthetic jet fuel in existing engines is modest on cost grounds compared with fossil fuels. Even accounting for declining

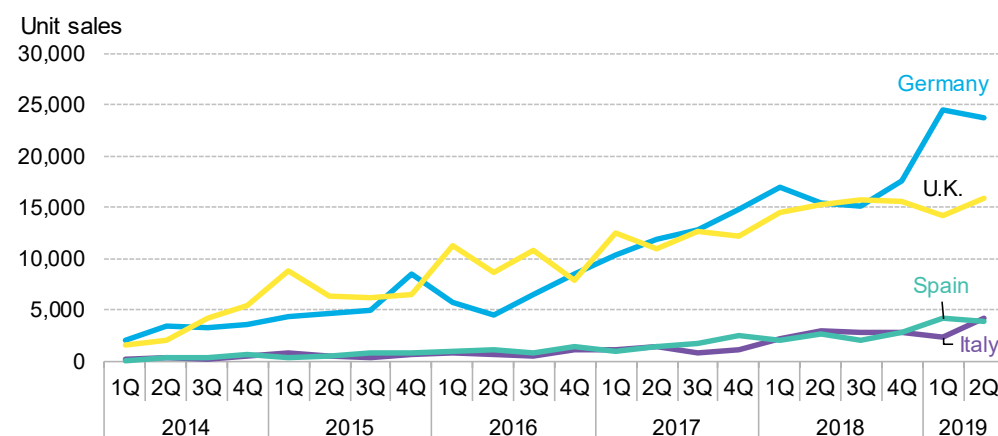
power prices, synthetic fuels would still cost around 80% more than jet fuel, according to industry estimates.

Some 60% of the rail network in Europe is already electrified and some 80% of traffic runs on these lines. The pathway anticipates that the remaining diesel infrastructure gradually switches to electricity, or hydrogen. The freight rail segment is the last to switch. Some energy efficiency gains will be offset by the anticipated increase in demand for high-speed rail due to the shift of freight and passenger transport from planes and heavy-duty trucks.

Southern European archetype

Sales of passenger EVs in the Southern European archetype have been modest to date, whereas they averaged 15% of sales in the Northern archetype in the two years ending 2Q 2019 (Figure 71). However, increased model availability, government support and improving economics mean that sales of passenger EVs in the Southern European archetype begin the 2020s at a lower level then quickly ramp up. As a result, by 2050, direct electrification has a similar share of the fuel mix in both archetypes. The international nature of commercial transport – whether by road or not – means that the trend for these transport segments in the Southern archetype is similar to that observed in the Northern neighbor.

Figure 71: Sales of passenger EVs



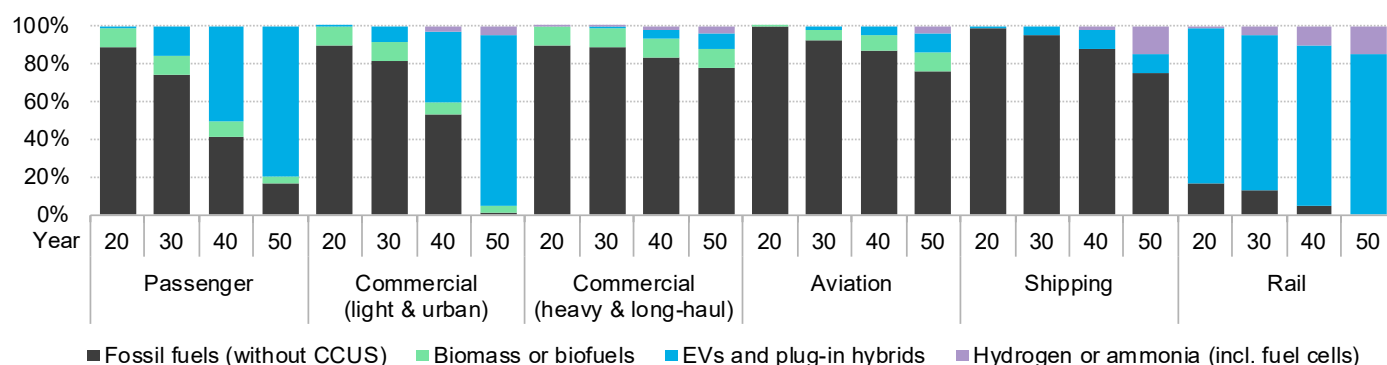
Source: BloombergNEF

Impact of energy use

The trends outlined above result in the changes in the composition of the transport fleet as shown in Figure 72. Electrification has the biggest potential for passenger and light & urban commercial road vehicles: thanks to favorable economics and policy, they account for 80-90% of the fleet by 2050.

In contrast, heavy and long-haul commercial road vehicles as well as long-distance aviation and shipping remain heavily dependent on fossil fuels for at least the next 30 years. Substantial government support would be required to overcome more quickly the challenge of battery and/or hydrogen density.

Figure 72: Breakdown of the fleet by fuel source across transport segments in the Northern European archetype

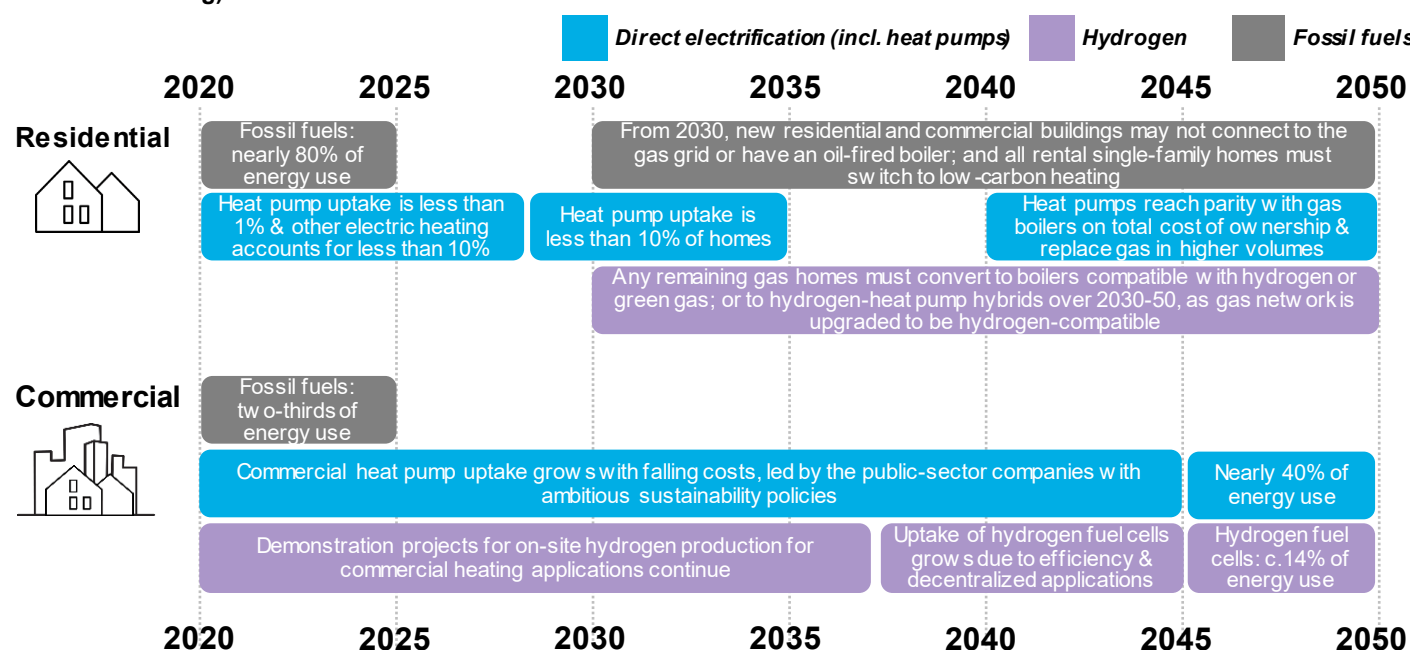


Source: BloombergNEF. Note: 'Commercial (light & urban)' includes buses.

A.2. Buildings

Around a third of final energy consumption in the Northern European archetype is for space and water heating in residential and commercial buildings (Figure 73). About half of that demand is met by natural gas, with another quarter from coal and oil. However, the fuel mix is set to change considerably over the next 30 years, driven by economics and consumer behaviour, particularly where a property is part of the existing stock and is occupied by its owner. Elsewhere some policy intervention is assumed.

Figure 73: Sector coupling pathway for the Northern European archetype – residential and commercial buildings (space and water heating)



Source: BloombergNEF

Direct electrification

The biggest change to the fuel mix for both residential and commercial buildings is the growth in direct electrification. In single family homes, air-source heat pumps are already cost-competitive with most oil heating systems in the Northern European archetype, and become cheaper than all oil systems over 2025-30.⁴⁰ However, they currently struggle to compete with traditional gas boilers, in particular due to high upfront costs⁴¹ and retail power prices that tend to be higher than gas on a kilowatt-hour basis. As a result, heat-pump uptake across all building types is limited until government introduces some policy support, in order to achieve its decarbonization ambitions. In particular, from 2030 all new residential and commercial buildings may not connect to the gas grid or have an oil-fired boiler. This is in line with bans being implemented by the U.K. and Netherlands. (Germany intends to introduce an emission-trading scheme on heating and transport fuel suppliers.)

In addition, we assume from 2030 that all rental single-family homes are mandated to switch to low-carbon heating options (including hydrogen-compatible gas boilers). This is required to overcome the split incentive that arises with the tenant paying the energy bills and the landlord being responsible for the capital investment decisions. In such circumstances, the landlord may not be incentivized to implement potentially expensive works if the resulting benefits (eg, lower energy bills) will accrue to the tenant. To further encourage this shift for rental homes and mitigate the split incentive, we anticipate that landlords may apply for subsidies on the upfront costs.

For homes in multi-family buildings, like apartment blocks or flats, air-source heat pumps (either window-mounted or commercial-scale for the whole building) and direct electric heating are both options. However, we assume uptake to be slower in this market because there is a wider range of technologies available, more homes are rented and more housing units will be on communal rather than individual heating systems.

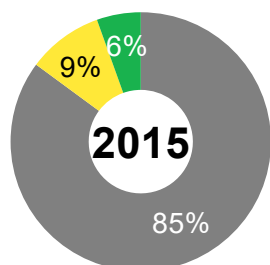
In commercial buildings, air-source heat pumps become cheaper than gas by 2040 on a total cost-of-ownership basis – the deciding factor for a commercial building that is occupied by its owner. When it is rented, operating cost is the main economic driver. Government could therefore reduce heat pump subsidies at this point. However, because owners of some buildings will still take account of upfront costs, some support may still be needed. We assume that a combination of corporate sustainability targets and economic decision-making drive low-carbon heating adoption in commercial buildings through 2050.

District heating

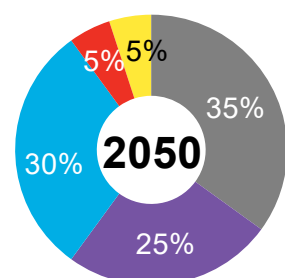
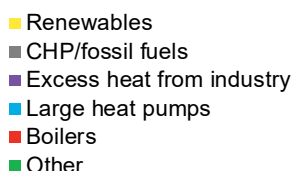
District heating is one of the three main pathways to decarbonize heating (with electrification and green gas) and can now use lower temperatures, making it easier to integrate heat pumps and other fuel sources. It is particularly good for efficient energy provision, in particular in areas of concentrated demand. We therefore assume that there is government support for district heating networks in cities, leading to their growing adoption after 2030, and the networks are required to be renewable, leading to an increase in the number of heat pumps and electric supply points. The ban on new-build gas connections, in addition to driving uptake of direct electrification technologies, also spurs new district heating for multi-family homes and commercial buildings.

40 The pathway assumes heat-pump costs fall 25% & improve in efficiency by 25% by 2050. Meanwhile, gas/oil boilers costs fall 5%

41 Current estimates of the upfront costs in Europe are 2,600-3,500 euros for a new gas boiler and 6,800-9,000 euros for an air-source heat pump. Ground-source heat pumps – ie, those that absorb thermal energy from the ground – are more expensive and more difficult to install. This report therefore focuses on the air-source variant.

Figure 74: District heating fuel mix in Europe

Source: IEA, BloombergNEF.



Source: Heat Roadmap Europe, BloombergNEF.

Note: A 'large heat pump' has more than 1MW of thermal output.

The vast majority of existing district heating networks in Europe use fossil fuels (Figure 74). However, the share of electricity is expected to expand as EU carbon prices rise and heat pump costs decline. This is in line with the Heat Roadmap Europe, which suggests that nearly a third of district heating could be fueled by large-scale heat pumps by 2050.

Hydrogen

Hydrogen fuel cells produce both electricity and heating for buildings where applied; in the Northern European archetype, which has high electricity retail prices, such systems can start to look cost-competitive in the 2030s – particularly for new build units or commercial, owner-occupied properties. However, high upfront costs still hold back adoption relative to heat pumps or other direct electric systems.

The biggest boon for hydrogen demand in buildings comes from establishing a hydrogen-compatible grid. As part of its decarbonization strategy, the Northern European archetype begins to convert the gas network from the 2020s, to either green gas (a combination of synthetic gas, biogas and renewable hydrogen) or to 100% hydrogen networks. This is in line with the strategies of various European governments, including Ireland and the U.K. Blends of hydrogen of 10-20% by volume are possible without converting pipelines and appliances in most of the gas grid. Switching to a 100% hydrogen network would require the roll-out of polyethylene piping for gas distribution networks by 2050, as well as a gradual switchover of in-building heating appliances and grid connection points to accommodate hydrogen in the decades leading up to 2050. Such a strategy helps to ensure continued use of the gas grid and potentially to avoid stranded assets.

The Northern European archetype mandates the conversion of the remaining gas homes to boilers compatible with hydrogen or green gas; or to hydrogen-heat pump hybrids between 2030 and 2050. As a result, from 2030, all homes looking to buy a gas boiler must buy a hydrogen-compatible heating unit or hybrid system instead. This is because heating units have a 20-year lifetime, and this is the latest possible date for phase-in of hydrogen-compatible technologies that is in line with a 2050 low-carbon mandate.

Southern European archetype

The pathway for buildings in the Southern European archetype differs in two main ways. First, air-source heat pumps are already cheaper over their 20-year asset lifetime in the Southern European archetype thanks to a milder climate, which brings higher coefficients of performance.⁴² Reversible air-source heat pumps, which can provide both heating and cooling, are particularly competitive. The position of air-source heat pumps relative to separate air conditioner and gas heating systems continues to improve in the 2030s due to declining upfront costs, with a payback period of 10 years or less by 2040. Residential homes and commercial buildings in the Southern archetype are expected to favor heat pumps over hydrogen-based fuel cells because the latter cannot provide cooling on their own.

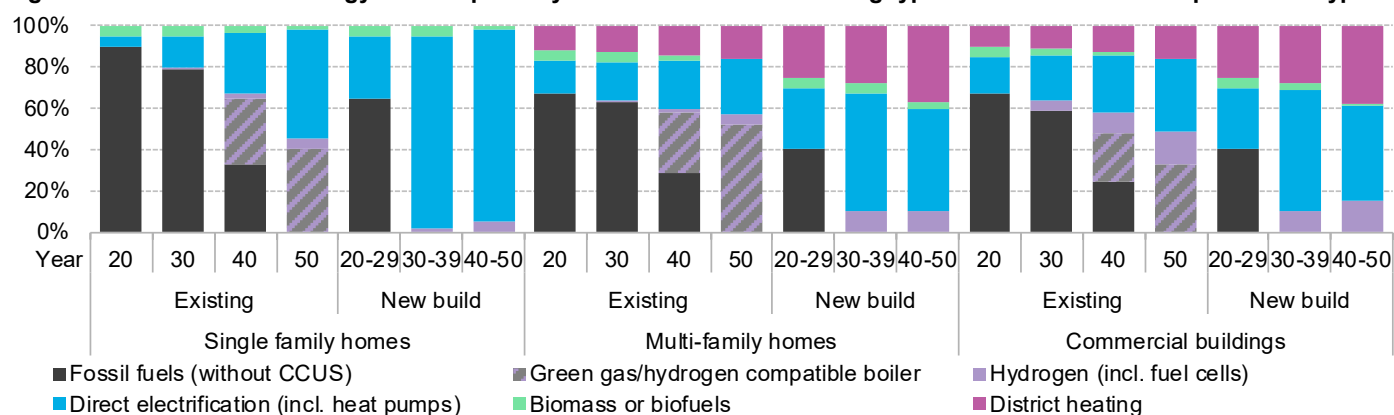
Impact on energy use

These trends result in the changes in the energy mix as shown in Figure 75. The share of electrification via heat pumps and hydrogen fuel cells increases the most in single family homes – from 5% in 2020 to more than 60% by 2050 – due to declining technology costs, and government subsidies in the early part of the period. On top of this share, power demand will also come from

⁴² The coefficient of performance (COP) is the number of kilowatt-hours of useful heat provided by 1kWh of electricity consumption. Heat pumps are most competitive in climates with milder winter temperatures because they can more easily extract the surrounding heat and convert it into energy.

homes that have installed hydrogen-only or hybrid heating systems. The greater efficiency of district heating in concentrated areas means that these networks account for a bigger share of energy consumption by other building types. Taking into account the increased use of electricity to fuel these networks by 2050, around half of energy consumption in multi-family homes and commercial buildings is met by direct electrification, hydrogen fuel cells and district heating.

Figure 75: Breakdown of energy consumption by fuel source across building types in the Northern European archetype



Source: BloombergNEF

Hydrogen-based fuel cells see some uptake, in particular by commercial buildings from the 2030s, and elsewhere from 2040. Some companies are motivated by sustainability mandates. Others are driven by the increasingly attractive economics, as fuel cells' capital costs for commercial building applications are expected to fall 50% by 2050. Reversible fuel-cell systems – ie, gas-to-heat-and-power or power-to-gas – are under development and expected to be available from 2030. These can be used for local energy storage and are attractive for decentralized energy systems.

The remaining energy consumption will remain on the gas network, but using boilers that are compatible for a decarbonized gas grid. We are agnostic as to the precise mix of this decarbonized network – it could be predominantly biomethane, a hydrogen-blend or a pure hydrogen network. However, since boilers are designed for a specific blend of hydrogen, we assume that all new boilers sold, after a certain point, must be compatible with the government-planned energy mix.

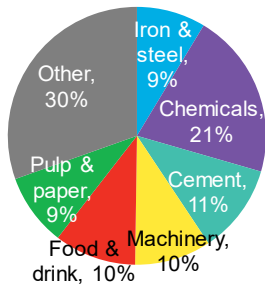
A.3. Industry

Industry has maintained a fairly stable share of final energy consumption in the Northern European archetype, at around a quarter since 1990. But on an absolute level, total demand for industry has fallen at a faster rate – 0.7% CAGR compared with 0.2% for the whole economy – with one reason being competition from low-cost producers like China. The pathway focuses on three industry sectors – iron & steel, chemicals and cement – due to their size and required energy inputs (Figure 76). Together they account for more than 40% of final energy consumption by industry and more than half of all industrial process heat demand.

In addition, their processes – eg, to transform limestone into cement clinker – require very high temperatures, of 1,100-1,600°C.⁴³ This is important because not every combination of fuel and

⁴³ Broadly speaking, BloombergNEF defines high temperature as being over 500°C, medium as between 200°C and 500°C, and low as less than 200°C.

Figure 76: Final energy consumption by industry sector (2017)



Source: Eurostat

technology can reach the desired manufacturing temperature level. For example, heat pumps are only available at present for low temperatures. Electric systems could replace some combustion-based processes currently fueled by coal and gas. But their application is specific to the suitability of the material and process. As a result, these focus sectors currently depend on fossil fuels.

The 'Other industrial sectors' category covers a broad range of areas, including food & drink, pulp & paper, machinery and aluminum. However, they are all (in the most part) on low or medium temperatures to generate process heat and their varied fuel mix, with some already having a substantial share of electricity (eg, aluminum) and renewables (pulp & paper).

The pathway does not assume any specific incentives or targets to promote direct or indirect electrification by industry. However, we expect governments with climate action ambitions – like the current administrations in the U.K. and Germany – to introduce incentives to promote decarbonization. Industrial heat pumps, electric boilers and other electrification technologies generally have higher capital costs than fossil-fuel equivalents, but lower O&M and fuel costs. Therefore, subsidies are likely to target the high upfront costs in order to spur uptake. In the short term at least, we expect governments to shield some industrial sectors from global competition (see box).

Iron & steel

In the short-to-medium term, the growth opportunities in electrification of the iron & steel sector are limited to increased use of electric arc furnaces for greenfield sites. One reason is limited availability of scrap iron: electric arc furnaces (EAFs) are used for secondary steelmaking, or recycling, rather than primary production. Scaling up EAF production would therefore require more iron and steel recycling. Another reason is cost: BloombergNEF does not expect wholesale power prices in Germany and the U.K. to fall below natural gas prices until 2045-50. That said, EAFs have had a relatively stable share of annual steel production in Europe (39-41%) in the last decade, with the remainder coming predominantly from coal-fired blast furnace-basic oxygen furnace (BF-BOF) plants.

Full electrification of primary steelmaking has yet to be proven at a commercial scale. While molten-oxide electrolysis is a pathway for primary steelmaking, no commercial-scale projects exist today. As such, its role in iron and steel production for the Northern European archetype is considered very limited even by 2050.

Instead, indirect electrification is the more likely path for iron and steel. Direct-reduction electric arc furnace (DR-EAF) technology, which uses natural gas for direct reduction and electricity for the second part of the process, is now a relatively established technology in North America, although adoption in Europe is still limited due to higher gas and power prices. Industry does not expect the share of production by gas-fired DR-EAF plants to rise substantially, and in any case it would have a relatively minor impact on power demand.

Of greater impact would be the introduction of hydrogen-fueled DR-EAF plants: the technology is the same as for gas-fired DR-EAF, but using hydrogen instead. We assume hydrogen-based steel production ramps up from 2030 when it is cost-competitive with 'expensive' gas- or coal-based production priced at \$12 (9 euros)⁴⁴ per MMBtu and \$310 (232 euros) per ton. Based on BloombergNEF's analysis of hydrogen costs and carbon price forecast,⁴⁵ it reaches cost parity with cheap coal (\$60, 45 euros per ton) and gas (\$2, 1.5 euros per MMBtu) by 2050. With

⁴⁴ All currency conversions use the forward exchange rate on the Bloomberg Terminal, unless stated otherwise.

⁴⁵ BloombergNEF clients can read more at: *Hydrogen: Making Fossil-Free Steel* – [web](#) | [terminal](#).

European gas prices trending in the range of 3.5-7.0 euros per MMBtu, this technology should be cost-competitive between 2030 and 2050.

Iron & steel also sees a bigger increase than the other industrial sectors in the share of energy from fossil fuels with CCUS by 2050. However, its use is still limited given the technology has yet to be proven at commercial scale. Integrated iron- and steel-making entails multiple, linked emission sources, making it difficult to capture more than 60% of greenhouse-gas output, although capture costs for iron & steel are still lower than in some industry sectors (see below). Various projects in Europe are working to help bring CCUS to the mainstream market. Tata Steel, for example, is working to commercialize a new substitute for the blast furnace process known as Hlsarna. This consolidates steel-making equipment, concentrates the CO₂ and is thus suited to the CCUS process without need for a gas-separation stage.

As with electrification technologies, we anticipate some government support for CCUS, as a significant barrier to its commercialization has been the lack of policies that place a value on avoided emissions. CCUS for steel production may reach commercial scale around 2035 but it is costlier than hydrogen, in particular given the integrated nature of steel plants and multiple sources of emissions. Deployment is likely to be earlier in areas with government-backed industry clusters (in particular close to CO₂ storage sites) due to economies of scale.

Cement

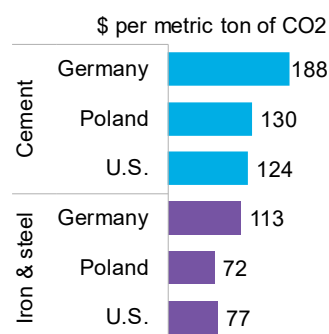
The cement sector sees the least change in its fuel mix, remaining most reliant on unabated fossil fuels by 2050. This is partly because decarbonization efforts focus on switching to low-cost and lower-carbon biomass and waste fuels, which can to some degree act as drop-in replacements. The biggest change in the fuel mix is the increase in direct electrification – but only from 2035. This is for two main reasons:

- In the first half of the period, it is constrained by the long asset lives in the cement sector and the lack of industrial-scale electric furnaces on the market able to reach the required temperatures of up to 1,450°C. Several technologies are being investigated and developed, including plasma, induction and microwave energy, but industrial-scale furnaces only become mainstream in the late 2040s.
- Another reason for the delay is that wholesale power prices in Germany and U.K. only fall below natural gas around 2045-50, according to BloombergNEF analysis.

Hydrogen could replace fossil fuels for heat production in the cement sector but its decarbonization potential is limited.⁴⁶ In the near term, the use of hydrogen will be limited on the grounds of economics because the cement sector can use cheaper biomass and waste streams. As a result, green hydrogen only becomes cost-competitive for high-temperature heat production with coal and gas by 2050, on the basis of BNEF's carbon price forecast.

The potential for CCUS is also limited in the cement sector because it has lower CO₂ concentration in its exhaust emissions – at around 19% CO₂ compared with nearly 100% in process emissions for ammonia. A lower concentration of CO₂ increases the capture costs: first-of-a-kind plants suggest carbon capture costs of some \$110 (99 euros) per metric ton for cement versus \$66 (60 euros) for iron & steel, according to estimates by the Global CCS Institute (Figure

Figure 77: Costs of CO₂ avoided for a first-of-a-kind CCUS plant



Source: Global CCS Institute

⁴⁶ Switching to hydrogen alone would not be able to decarbonize cement production because fuel combustion only contributes some 40% of the sector's emissions. Other strategies such as CCUS would need to be implemented. BloombergNEF clients can read more in: *Hydrogen: The Economics of Industrial Heat* ([web](#) | [terminal](#)).

77).⁴⁷ There are projects underway to concentrate the CO₂ from easier capture – eg, the Calix Flash Calcination process, which HeidelbergCement is testing in Europe. The costs of CO₂ transport and storage would also be higher for the cement sector, which is spread across nearly 200 kilns around the EU. In contrast, steel and petrochemical plants are often clustered, making possible economies of scale from sharing CO₂ pipeline and using offshore storage facilities.

The cement sector relies more on biomass for energy than iron & steel and chemicals. However, it is not expected to be a priority sector for bioenergy resources because it has alternative options with increasingly favorable economics. Also, there are concerns regarding biomass feedstock supply and whether it meets increasingly strict sustainability regulations.

Chemicals

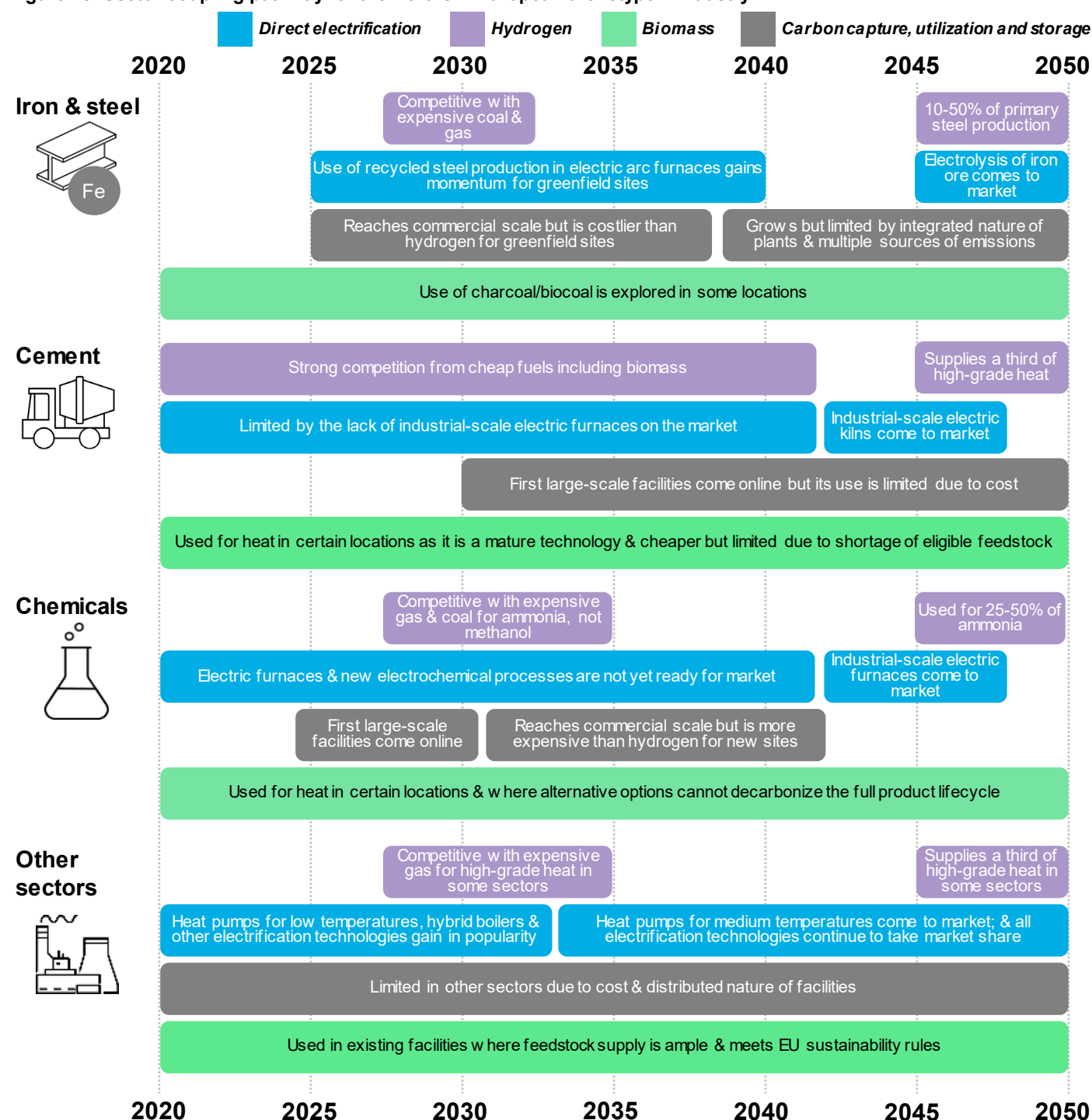
Chemicals require the highest volume of energy of all industry sectors but the pathway for its fuel mix varies by the product in question. Ammonia, which accounts for the second-biggest share of energy use and CO₂ emissions in the chemicals sector (after plastics), has significant potential for green hydrogen. Our analysis indicates that by 2030, hydrogen-based ammonia production is cost-competitive with expensive gas (\$12, 9 euros per MMBtu) and coal (\$120, 90 euros per ton), based on BloombergNEF's carbon price forecast. It reaches cost parity with all gas and coal by 2050. The conversion process would be relatively simple by retrofitting the hydrogen electrolyzers or adding them into existing processes. However, the prospects of hydrogen for methanol production look less rosy as it is only competitive with expensive coal by 2030, and even 20 years later it is not competitive with cheap gas.

The use of direct electrification in the chemical sectors is limited by the need for large volumes of energy to produce temperatures of 800-1,100°C and the lack of industrial-scale electric furnaces, which require substantial development work to bring them to commercial readiness. The pathway assumes the use of electricity increases over time as power prices and technology costs decline, in particular for the production of process heat for chemicals other than ammonia. This is because they primarily generate heat from fossil-fueled boilers that are separate from the chemical reactions. The share of direct electrification ratchets up in the 2040s, as industrial-scale electric furnaces for chemicals production come to market.

As with cement production, the potential for CCUS in the chemicals sector is limited by its distributed nature: this technology is most effective when implemented on sizeable point sources with concentrated CO₂ emissions close to suitable storage. To be an effective decarbonization option for just the plastics industry, emissions would need to be captured from the 50 or so steam crackers across the EU as well as the hundreds of waste-incineration plants and upstream refineries. Together with aviation, chemicals (eg, plastics and ammonia) is a priority sector for bioenergy resources due to the lack of alternative options. However, its use will still be limited by the high cost relative to other options.

47 Global CCS Institute, Global Costs of Carbon Capture and Storage, 2017.

Figure 78: Sector coupling pathway for the Northern European archetype – industry



Source: BloombergNEF

Other industry sectors

The main trend for the other industry sectors is the growth of direct electrification – in particular heat pumps and dry heating. This is principally due to economics and technology maturity: heat pumps and microwave drying are already proven at a commercial scale in these sectors for low-

to-medium temperatures, while electric boilers are also commercially available. Third-party literature suggests that industrial heat pumps are used by 30% of European installations for space heating, hot water and cooling, 10-20% for concentration applications and dehumidification, and less than 5% for drying and desalination. Early candidates include: heating, ventilating and air conditioning in all sectors; food & drink, pulp & paper, textiles and wood.

With regard to the economics, industrial heat pumps have lower operating costs than gas boilers in Europe, and their associated fuel costs are expected to decline with the decrease in electricity prices. However, on a capital cost basis they are more expensive than gas boilers – leading to payback periods of 4.8 years or more, which can make them uneconomical in the eyes of most industrial site owners. The other challenge is that heat pumps are not proven to reach temperatures above 180°C, which means they cannot displace all heat demand on site – and another system for higher-temperature processes will need to remain in place.

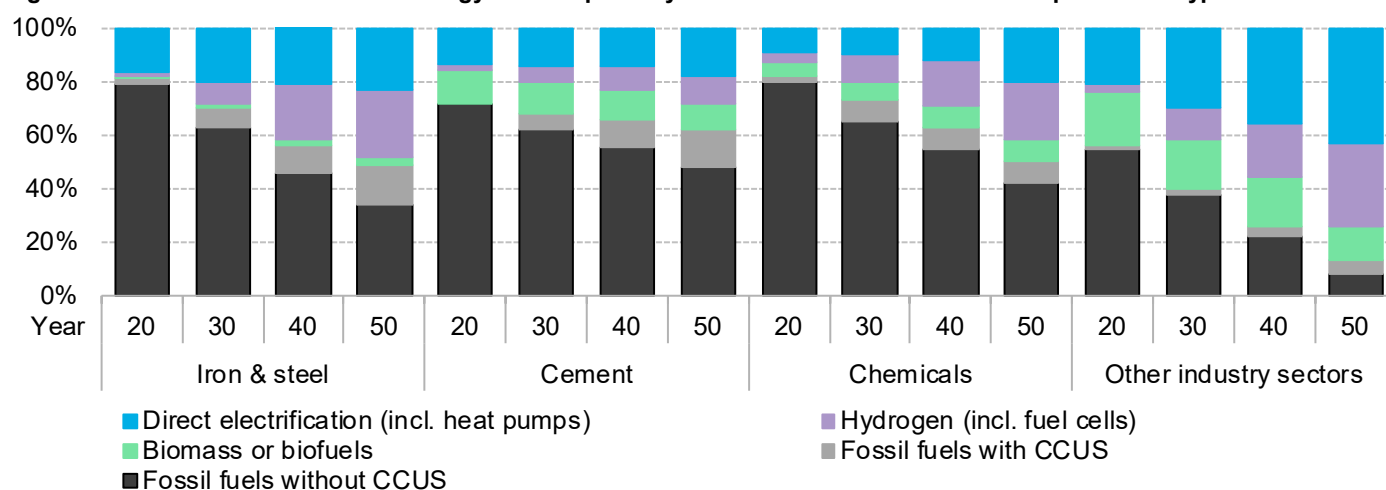
Electric boilers do not enjoy the same efficiency benefits as heat pumps and are currently more expensive than gas boilers in terms of opex. In particular, the current low prices of natural gas are expected to deter uptake of electric boilers in the near term: eg, for our Northern European archetype, gas prices have averaged 18 euros per MWh compared with wholesale electricity at 51 euros. However, electric boilers will also benefit from decreasing power prices. Increased volatility from more variable renewables in the power mix would increase the incentive for ‘flexible’ electrification technologies (eg, hybrid boilers). This pathway therefore assumes that governments with decarbonization ambitions – like the current administrations in the U.K. and Germany – will introduce incentives to target these high upfront costs for electrification technologies like heat pumps.

Green hydrogen use is also expected to ramp up in the other industrial sectors, in particular in the latter half of the period. Economics will be the primary driver: by 2030, high-grade industrial heat from green hydrogen could become competitive with heat derived from fuel oil at a carbon price of \$120 (90 euros) per metric ton of CO₂e, and with all coal and petcoke at a price of \$130 (97 euros) per metric ton of tCO₂e. A CO₂ price of \$50 (37 euros) would be needed for hydrogen to be competitive with expensive natural gas, while \$215 (161 euros) would be required to outcompete cheap natural gas. However, by 2050, the carbon price required for green hydrogen to be competitive would be below \$100 (75 euros) per metric ton of tCO₂. Partially blending hydrogen into existing fuel streams in the initial stages of adoption may be a way to gradually introduce hydrogen into industry.

CCUS works best for industrial processes that emit substantial volumes of concentrated, high-pressure CO₂. The practicalities and high costs relative to other technology options (eg, electrification) suggest that the ‘Other industry sectors’ are likely to make limited, if any, use of CCUS within the relevant timeframe. Biomass is used for low- and medium-temperature heat where feedstock supply is ample and low-cost (eg, waste residues from pulp & paper) and meets EU sustainability rules.

Impact on energy use

Under the pathway, none of the focus sectors eliminates the use of fossil fuels without CCUS. This is due to the required level of technological progress, process change and investment to achieve full decarbonization (Figure 79). By 2050, cement remains most dependent on unabated fossil fuels, which account for half of energy use in that year compared with a third in iron & steel and 42% for chemicals.

Figure 79: Breakdown of industrial energy consumption by fuel source in the Northern European archetype

Source: BloombergNEF

Green hydrogen production becomes cost-competitive earlier for iron & steel and some chemicals relative to cement production. As a result, the first two sectors see their share of direct and indirect electrification expand 30 percentage points over the period, to just under half for iron & steel and 42% for chemicals. The share for the latter is smaller because it is a priority sector for the likely constrained supply of sustainable bioenergy resources. In comparison, direct and indirect electrification account for 28% of energy use for cement production by 2050.

Southern European archetype

Industry in the Northern archetype may consume almost double the volume of energy each year compared with its Southern neighbor. But it accounts for a similar share of total final energy consumption in both archetypes (at around a quarter), meaning their pathway for industry is relatively similar. The main difference is the Southern archetype has a bigger share of unabated fossil fuels in its energy mix by 2050. This is for two main reasons: First, the cement sector in the Southern archetype accounts for a bigger share of energy consumption by industry compared with chemicals. Secondly, it starts to use CCUS at a later date than the Northern archetype and makes less use of the technology over the period. The Southern archetype has made less progress toward CCUS deployment, with a score of 39 out of 100 for its CCUS readiness compared with a score of 56 for the Northern archetype, according to the Global CCUS Institute. This means that the region has shown less interest in, and there is less government support for, the technology, the legal environment is less well developed, and it has lower CO₂ storage resources.

The other industry sectors already have more electricity in their fuel mix and make the most progress away from unabated fossil fuels, which have a share of less than 10% by 2050. Processes in these sectors tend to use lower temperatures compared with iron & steel or chemicals production, for example. They therefore may switch earlier to direct electrification, which accounts for 43% of energy use by 2050, in addition to nearly a third produced by green hydrogen.

Appendix B. Assumptions

B.1. Carbon

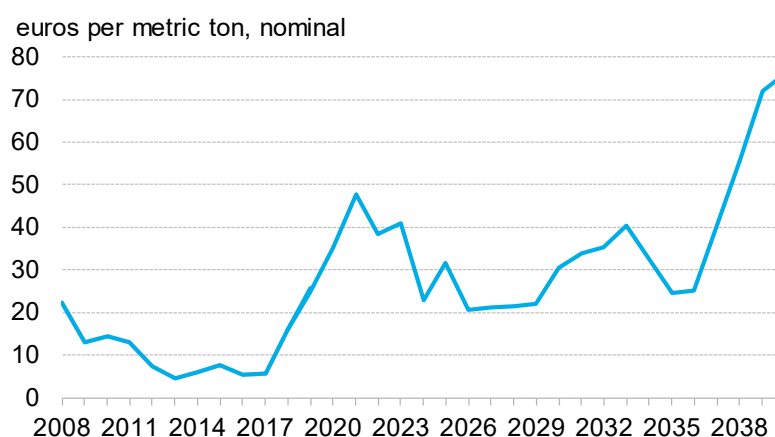
Table 17: Drive cycle definitions for commercial vehicles

Thousand miles per year	
Urban	<30
Regional	30-100
Long-haul	>100
Utility	Varies greatly

Source: BloombergNEF

The sector coupling pathway described in this report is based on BloombergNEF's EU carbon price projections shown in Figure 80. We have used this forecast – rather than the slightly different forecast in our *2H 2019 EU ETS Market Outlook* (available to clients at: [web](#) | [terminal](#)) – because it was used in our *2019 New Energy Outlook*, which is the basis for our analysis of the impact of sector coupling on the power system. In addition, even if we input the 2H 2019 increased price outlook, it has little-to-no impact on the sector coupling pathway and associated analysis.

Figure 80: European carbon price projections



Source: BloombergNEF. Note: This forecast differs slightly from the BNEF, *2H 2019 EU ETS Market Outlook* (available to clients at: [web](#) | [terminal](#)).

B.2. Sectors

For more detail on the methodology behind the sector coupling pathway for **transport**, see the [free public summary](#) of *Electric Vehicle Outlook 2019*, or BloombergNEF clients can access the full report and underlying datasets at [web](#) | [terminal](#).

In essence, our passenger EV forecast has two main components. The first component forecasts the overall passenger-vehicle market, considering the impact of shared-mobility services and autonomous vehicles, as well as EV adoption within these categories. For autonomous vehicles we only consider Level-4 or above levels of autonomy, and we assume such vehicles will be only used for shared-mobility services ('robotaxis'). The second component is EV adoption within the privately owned vehicle category. Our short-term (2019-23) EV sales forecast is based on EV model availability, local policies and historical sales trends. In the long term (2024-40), the forecast of privately owned EVs is driven by a consumer adoption model taking into account the economics of EVs in different vehicle segments.

The forecasts for the adoption of different fuels in the future truck fleet begins with an estimate of road freight demand. We split that across the segments shown in Table 17 and derive the fleet

and sales needed to meet it. Finally we use the relative total cost of ownership of different drivetrains – adjusted for model and fueling infrastructure availability – to estimate the annual adoption of each alternative fuel.

The sector coupling pathway for **buildings** is based on proprietary BloombergNEF analysis of the expected total cost of ownership for air-source heat pumps compared to oil and gas boilers, and the evolution of the housing stock across European markets until 2050. This forms the baseline of our approach, but the pathway also assumes regulatory and policy mandates drive uptake of low-carbon heating for buildings. For instance, there are segments of the building stock where ownership and rental structures will distort economic signals. This is applicable to the rented housing market as well as leased commercial building stock. Additionally, a conversion to green gases like hydrogen over natural gas would require significant policy intervention to assure a changeover in infrastructure. Finally, there is existing precedent for stricter regulations on new build developments. This analysis assumes a ban on new homes and offices using gas, coal or oil for heat generation – a policy already adopted in several European markets – from 2030 onwards.

B.3. Flexibility scenarios

The modelling of the sector coupling pathway throughout this report use the same inputs, for instance on technology costs and commodity prices, as BloombergNEF's *New Energy Outlook 2019*. However, the power demand inputs vary by scenario, depending on the extent of direct electricity demand that emerges from coupling (see details below). This affects absolute and intraday load profiles for the model. The flexibility scenarios are based on the following assumptions:

- **No coupling:** this scenario assumes that *no* additional electrification of buildings, transport and industry occurs from today's levels. Note that this scenario differs from our *New Energy Outlook 2019*, which anticipates a baseline of direct electrification of road transport by 2050 based on consumer uptake modelling.
- **Inflexible coupling:** this scenario assumes no flexibility from coupled sectors. Public EV charging infrastructure roll-out is minimal and private charging stations are not dynamic (ie, they do not respond to price signals). As a result, the electrification of road transport creates a significant fixed load of charging demand overnight. In residential buildings, the electrification of heat demand also has a fixed profile (does not heat in a 'smart' way), based on real hourly usage data from the U.K. These two sectors create a substantial amount of additional inflexible power demand by 2050.
- **Flexible coupling:** this is our central scenario for this report and assumes that coupled sectors have some demand-side flexibility. In transport, EV charging infrastructure allows for just over half of the passenger fleet and a quarter of the commercial fleet to charge dynamically by 2050. In buildings, well-insulated homes are a source of flexibility for heat demand. Air-source heat pumps in efficient homes deliver heat three hours before it is needed, helping to even out the load profile of electricity demand in buildings. To calculate the share of the efficient housing stock, we assume an annual retrofit rate of 1% and new build rate of 0.4% until 2050, increasing the share of efficient homes in the archetype from around 10% in 2018 to 40% in 2050.
- **Full sector coupling:** this scenario assumes the same assumptions as our flexible coupling scenario, but includes additional demand volumes expected for the electrification of commercial building heating demand and industrial process heating, detailed in Appendix A.

- **Highly flexible coupling:** this scenario assumes a high level of demand-side flexibility. The roll-out of EV charging infrastructure allows for a significant amount of the vehicle fleet to charge dynamically. This scale of dynamic charging availability would require significant policy support and consumer uptake. In buildings, we apply the same principles as the flexible coupling scenario for the load profile of heat demand in efficient homes, but double the retrofit rate. As a result, this scenario reaches a 50% share of efficient homes by 2050. This would also would require substantial policy support for energy efficiency measures. Finally, this scenario assumes higher roll-out of demand response capacity due to effective market design to enable both dispatchable and non-dispatchable load response.

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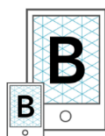
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