NET ZERO 2050

TOWARDS FOSSIL-FREE ENERGY IN 2050

cambridge econometrics
clarity from complexity

elementenergy

MARCH 2019

ACKNOWLEDGEMENTS

This report is the outcome of a year-long effort of deep analytical work, conducted by Element Energy and Cambridge Econometrics, which aimed to assess the feasibility of a fully decarbonized EU energy system by 2050, in line with the EU's commitment under the 2015 Paris Agreement, and on the basis of a set of scenarios that explore the extent to which energy efficiency, smart electrification and green molecules can be the drivers for this transition in the EU's power, heat and transport sectors.

All of the assumptions, as well as the different scenarios used in this study, were developed in close dialogue with an advisory group of companies, academics and NGOs. The European Climate Foundation wishes to thank the following companies and organisations: ABB, Agora Energiewende, the Buildings Performance Institute Europe (BPIE), the European Heat Pump Association (EHPA), E3G, European Trade Union Confederation (ETUC), Renault, Eurelectric, Fluxys, Iberdrola, IndustriAll Europe, GRT Gaz, Ørsted, Transport & Environment, Friends of the Earth Europe, WindEurope, SmartEn, SolarPower Europe, Climate Strategy & Partners, Gasunie, WWF European Policy Office for the valuable feedback they have provided to the project.

The willingness of these organisations and experts to be consulted in the course of this work should not be understood as an endorsement of all its assumptions and conclusions.

This report is funded by the European Climate Foundation, which itself is funded solely from private philanthropic organisations. ECF does not have any financial ties to EU political bodies or to private entities.

The Analytical Team:
Element Energy
Foaad Tahir, Michael Joos, Emma Freeman, Sam Foster, Shane Slater

Cambridge Econometrics
Eva Alexandri, Richard Lewney, Jamie Pirie, Phil Summerton

Project coordination (European Climate Foundation):
Dries Acke, Stijn Carton, Pete Harrison

Report design:
www.lindsayynobledesign.com

NET ZERO 2050

DISCLAIMER

This report has been commissioned by the European Climate Foundation (ECF). It is part of the Net-Zero 2050 series, an initiative of the ECF with contributions from a consortium of experts and organisations. The objective of Net-Zero 2050 is to start building a vision and evidence base for the transition to net-zero emission societies in Europe and beyond, by midcentury at the latest. The Paris Agreement commits us to making this transition, and long-term strategic planning shows that many of the decisions and actions needed to get us on track must be taken without delay.

Reports in the series seek to enhance understanding of the implications and opportunities of moving to climate neutrality across the power, industry, buildings, transport, agriculture, Land Use, Land-Use Change and Forestry (LULUCF) sectors; to shed light on some of the near-term choices and actions needed to reach this goal, and to provide a basis for discussion and engagement with stakeholders and policy-makers.

For reasons of the level of detail of modelling needed, this report uses different modelling tools than the CTI 2050 Roadmap Tool that has been developed and used for other analyses in this series. Care has been taken however to ensure consistency on the key parameters.

With acknowledgement of the source, reproduction of all or part of the publication is authorised, except for commercial purposes. For more information, please contact Stijn Carton: Stijn.Carton@europeanclimate.org

CONTENTS

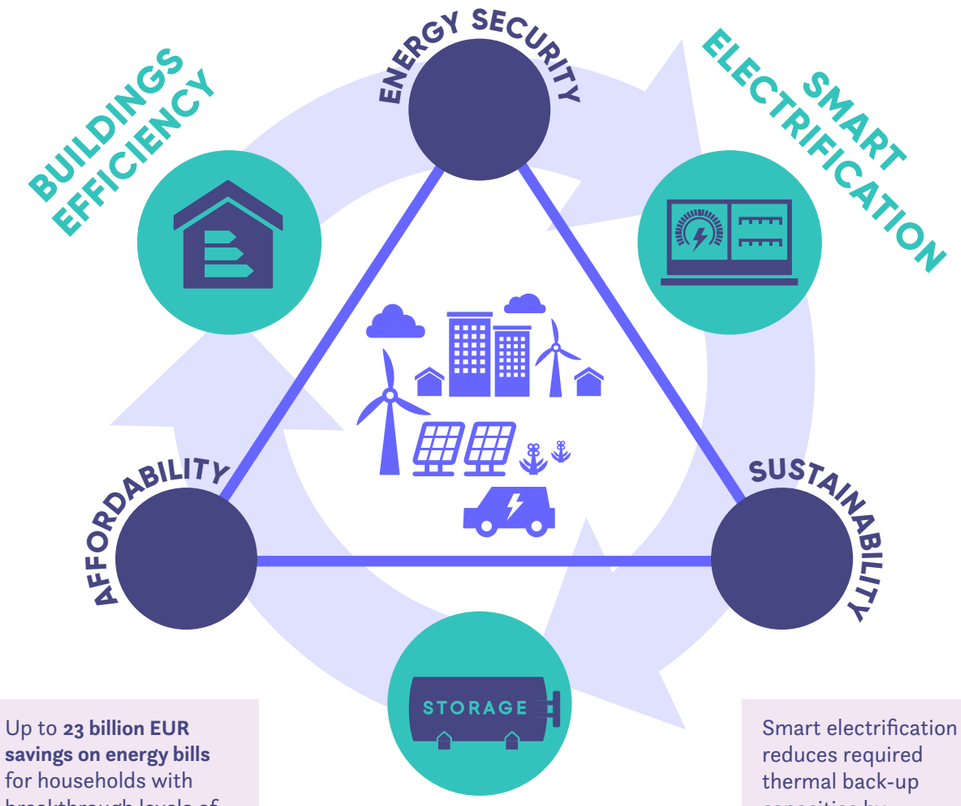
4 EXECUTIVE SUMMARY
10 1. INTRODUCTION
11 1.1 SYSTEM DRIVERS AND SCENARIO DEVELOPMENT
14 1.2 COUNTRY ARCHETYPES
15 1.3 TECHNOLOGIES
16 1.4 WHOLE SYSTEM MODELLING
17 1.5 MACROECONOMIC MODELLING
18 2. ENERGY SYSTEM IMPLICATIONS
20 2.1 BUILDINGS EFFICIENCY - REDUCING THE HEAT DEMAND PEAK IN BUILDINGS COMES WITH SUBSTANTIAL ENERGY SYSTEM BENEFITS
21 2.2 CLEAN ELECTRICITY AND SMART FLEXIBILITY - A SELF-REINFORCING DYNAMIC
25 2.3 LONG-TERM STORAGE - CRITICAL IN COLDER CLIMATES AND A POTENTIAL KEY ROLE FOR GREEN HYDROGEN
31 2.4 INVESTMENT IN ELECTRICITY INFRASTRUCTURE KEY TO ALL SCENARIOS
32 3. MACROECONOMIC IMPLICATIONS
33 3.1 KEY DRIVERS OF THE MACROECONOMIC OUTCOMES
36 3.2 MAIN FINDINGS
38 3.3 ISSUES RAISED BY THE MACROECONOMIC ANALYSIS
40 4. APPENDIX: MODELLING METHODOLOGY
41 4.1 ENERGY SYSTEM MODELLING
44 4.2 ANNUAL HYDROGEN PRODUCTION AND STORAGE
44 4.3 DISPATCHABLE GENERATION OPERATION
45 4.4 ANALYSIS METHOD: MACROECONOMICS
47 ENDNOTES

EXECUTIVE SUMMARY

This study examines how zero-carbon energy systems in Europe can function, taking the European Commission's long- term strategy towards a Net Zero Economy by 2050 as its starting point.

The study is unique in offering an in-depth analysis of the integration of power, road transport and residential heating sectors across Europe. It looks at six scenarios covering a wide range of zero-carbon technologies and energy carriers for a set of archetypes that represent the different climatic zones of Europe (Northern European vs Mediterranean).

The report finds that several different configurations of fossil-free energy system are feasible in Europe and each comes with socio-economic benefits when compared to a current-policies baseline. But clear infrastructure choices and robust policies are required to steer the transition in ways that keep the economy competitive while securing the best deal for European citizens.



Up to **23 billion EUR savings on energy bills** for households with breakthrough levels of smart electrification and deep buildings efficiency

LONG-TERM STORAGE

Smart electrification reduces required thermal back-up capacities by up to **54%,** and reduces renewable curtailment by **70%**

Net job creation across the European economy in all zero-emissions scenarios, with up to **1.8 million additional jobs** in a pathway with breakthrough levels of smart electrification and deep buildings efficiency.

Targeted use of green hydrogen for long term storage. Extending the use of green hydrogen to residential heating and road transport sectors risks supersizing the energy infrastructure, adding up to +36% of investment costs. Savings in electricity infrastructure are outweighed by costs for electricity generation and gas infrastructure (+248%)

Buildings efficiency in combination with smart technologies reduces total system cost by up to **22%** due to lower infrastructure investments and operational cost.

The trio of objectives sometimes known as the 'energy trilemma' (sustainability, security and affordability) are generally thought to be in tension. But this report suggests the reverse. They can mutually support each-other. For example, deeper decarbonisation means greater investment in European energy infrastructure and clean technologies, which, in turn, reduces spending on fossil fuel imports substantially. This would raise real incomes for households in Europe, boosting employment across the economy.

What stands out from the study are the potential savings in energy spending for households of up to €23 billion compared to a current policies baseline, as well as the net creation of a potential 1.8 million jobs across Europe, if a pathway including deep efficiency and smart electrification is chosen. The report does foresee structural shifts between sectors, away from fossil-fuel reliant industries towards electrical engineering and manufacturing, and so underlines the need for efforts to be made to ensure workers are re-trained for quality jobs in the growth sectors of the future.

The report identifies three features of a fossil-free energy system that are common to all possible configurations:

1

BUILDINGS EFFICIENCY

Measures to improve the thermal efficiency of buildings require upfront investment but lead to significant savings down the line – up to 22% when applied with smart technologies – due to avoided investments in energy infrastructure and generation assets. This is mainly thanks to the mitigating effect that efficiency measures have on peak demand for heating in buildings. Means should be found to remunerate customers for these avoided system costs.

2

CLEAN ELECTRICITY AND SMART ELECTRIFICATION

The report shows that, as electricity can decarbonise cost-effectively, it becomes attractive to maximise the value of carbon-free electricity in all sectors of the economy such as mobility, buildings and industry. In turn, smart electrification in these sectors offers flexibility to a power sector that will be dominated by variable renewable sources. The study shows that electrification, if smartly integrated in the energy system, can reduce the need for thermal back-up by up to 54% and renewables curtailment by up to 70%.

3

LONG-TERM STORAGE

This is a key challenge for any zero-carbon energy system. Especially in colder Northern European countries with a strong seasonal heat demand pattern there will be extended periods of insufficient renewable energy available. Heat networks (powered by district heat pumps) can provide an important option for rebalancing seasonal heat demand. In this report, heat networks and green hydrogen (generated from variable renewable sources via electrolysis) are shown to be technically viable options for the required longer duration storage of energy.

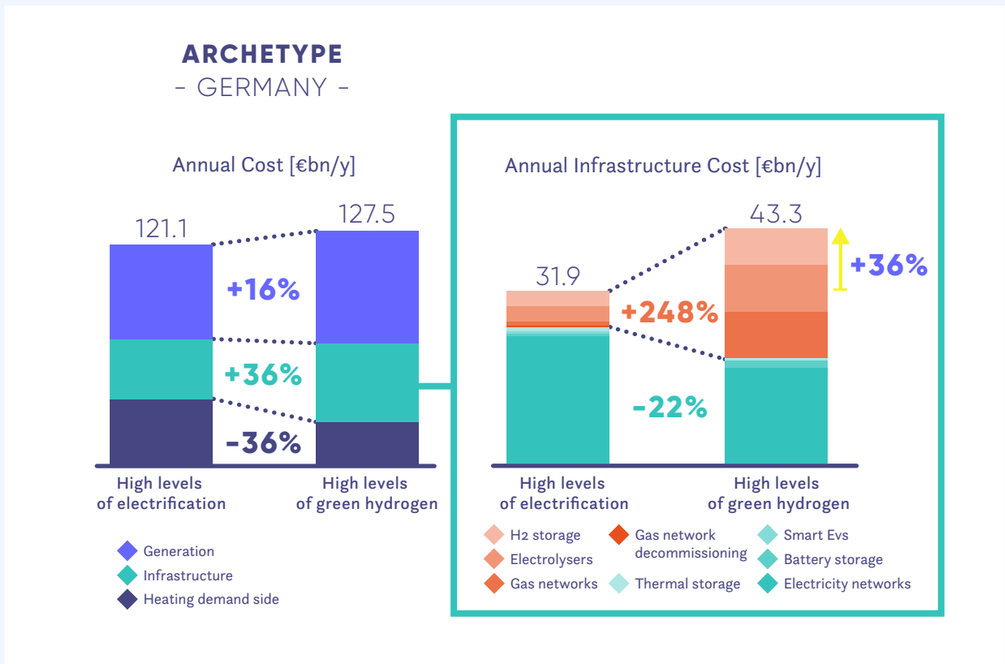
None of the scenarios in this study relies entirely on direct electrification of all demand. Rather, the study confirms the *complementarity* of direct electrification with carbon-neutral green gases and heat networks. **All zero-carbon solutions will require upscaling if the EU is to achieve its 2050 climate goals.**

The analysis, nonetheless, confirms the importance of maximising energy efficiency and smart electrification, while steering available green hydrogen to the specific applications where it can add the highest value, being: seasonal storage for peak electricity supply in winter time.

The scenarios in the study that rely on green hydrogen beyond these functions (for example in road transport and residential heating) increase energy system costs and household energy bills. Households may be forced to spend an additional €165-214 billion on energy in 2050 in green hydrogen heavy scenarios, whereas deep efficiency and smart electrification scenarios could save European households up to €23 billion compared to a current policies scenario.

The study finds that the *savings* in electricity infrastructure (-22%) from using more green hydrogen are outweighed by the *additional investments* that would be required for electricity generation to produce them (+ 16%) and gas network upgrades and maintenance (+248%).

These findings, on the economics and energy system implications of green hydrogen, underline the need for careful use of green hydrogen, avoiding competition with smart electrification and buildings efficiency.



MESSAGES TO POLICY MAKERS

The report confirms that a fossil-free European energy system in 2050 is not only technically feasible but socially and economically attractive. Decision-makers can, therefore, confidently develop policies that create markets for zero-carbon solutions while progressively phasing out the use of all fossil fuels across the energy system. The following policy actions are essential:

1) ***Prioritising the robust implementation of both the EU Clean Energy for All Europeans Package and the Mobility Package.***

   This is crucial for accelerting investment in renewables, buildings-efficiency and electro-mobility in the coming years, although more is needed in light of the 2050 Net-Zero goal. In addition, future energy policy initiatives should aim to overcome compartmentalisation and apply the lens of renewables, smart electrification and related sector integration across the board.

2) ***Aligning EU energy infrastructure policies and financial instruments with the EU's Net Zero Emissions goal.***

   Public funds should drastically scale up their support for buildings renovation, renewables and smart electrification, and end further support to fossil fuel infrastructure. EU decision-makers should, therefore, reopen the outdated EU infrastructure regulations, as these regulations are of huge importance for guiding public spending in the Multi-Annual Financial Framework (in particular Connecting Europe Facility, Cohesion Funds and Invest EU) and for the EU's public banks (the European Investment Bank and the European Bank for Reconstruction and Development). Further elaboration of the governance framework for increasingly localised energy infrastructure will be needed, including attention to the sequencing of decisions and the level of jurisdiction at which they are made.

3) ***Accelerating innovation and learning around smart electrification.***

   Given the importance of smartening energy systems and the opportunities and challenges that arise from new technologies and digitalisation, it is essential to develop a robust innovation agenda around smart electrification. This could include preparing for accelerated-learning, for example through dedicated learning platforms, sometimes known as "sandboxing", and best-practice sharing. The aim must be to accelerate the deployment, at scale, of lab-proven innovations, overcoming the so-called "valley-of-death". This aspect is elaborated upon in another report in this Net Zero 2050 series: "Funding Innovation to Deliver EU Climate-Competitive Leadership"

4) ***Develop solutions for high-value applications like long-term energy storage.***

   Heat networks and green hydrogen are shown to be important options for supporting long-duration storage. For green hydrogen, an essential first step for policy-makers is to develop clear, science-based definitions, standards and terminology to distinguish between other types of alternative gases on the basis of their lifecycle greenhouse gas emissions. Only when definitions are clear should decision-makers look at supportive policy frameworks. Europe could also look at assuming industrial leadership in key emerging technologies for green hydrogen, like electrolysers, as this will be a key component for carbon-neutral energy and industrial systems in Europe and around the world.

5) ***A more comprehensive "just transition" strategy for all affected sectors of the economy.***

   The transition to a Net Zero Economy will impact regions and workers above and beyond the coal mining sector. Dedicated efforts must be made to ensure workers have the skills needed for high-quality, well-paid jobs in the growth sectors of the future.

1

INTRODUCTION

Europe is entering a new phase in the decarbonisation of its economy. The progress made in the last decade with regard to improvements in energy efficiency and increasing the share of electricity generated by renewables, means that, in this next phase, the key questions revolve around the role of electrification and sector integration with mobility, heating and some industrial processes. This is becoming even more relevant given that climate ambition in line with the Paris Agreement requires Europe to reduce emissions faster and deeper in these sectors, to zero carbon by 2050, as has also recently been explored in the European Commission's communication: 'A Clean Planet for all. A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy'.

With this challenge in mind, the European Climate Foundation (ECF) has consulted extensively with key partners in this transition and commissioned Element Energy and Cambridge Econometrics to assess the feasibility of a fully decarbonised EU energy system by 2050. This assessment was made on the basis of a set of scenarios that explore a wide range of technological options for supply, demand, infrastructure options, flexibility, and smartness, in recognition of the fact that there is still great uncertainty over which of these options offers the most attractive pathway to decarbonisation. The study then uses a multi-vector, Whole System Model, approach to determine the configuration of the system to respond to these options, while ensuring that hourly supply of energy is secure. The cost of each scenario, and the relative shift of investment in generation, infrastructure, and end-use, is explored in the next chapter. These costs are then used in the Pan-EU macroeconomic model E3ME, and the results are presented in chapter 4.

The analysis conducted by Element Energy and Cambridge Econometrics provides us with key insights into the energy system adequacy and cost, as well as the macroeconomic impacts of each of these scenarios and thus serves to inform the policy makers on some of the key no-regret choices that can be made in the coming years, so as to set the EU up for success in meeting its full decarbonisation objective.

1.1 SYSTEM DRIVERS AND SCENARIO DEVELOPMENT

This project explores configurations and the cost of the energy system where electricity, heat and transport, all are fully decarbonised by 2050. Numerous studies have identified options for decarbonising Europe; but at its core this study determines what is required in a future in which there is widespread electrification of the demand side, and zero carbon electricity is supplied primarily with Variable Renewable Energy Sources (VRES): wind and photovoltaics. The scenarios in focus for this study are inherently challenging because they explore the extent to which the power system can cope with balancing supply and demand over all hours (i.e. system adequacy), with limited recourse to thermal power generation to act as a flexible source of electricity.

ZERO CARBON ENERGY SYSTEMS: DRIVERS

When considering whether a decarbonised power system is adequate to meet demand at all hours of the year, and under a variety of weather conditions, there are a number of system stresses which could challenge the power system.

Seasonal peaks in demand (such as space heating) are challenging to supply because they may be months in duration, and VRES capacity may not be sufficient in these times, even if VRES is sufficient to supply demands for other seasons. Seasonality of heating demand is an important factor in determining the resulting zero carbon system, potentially requiring higher generation capacities, increased VRES curtailment, higher peak infrastructure investment, and long-term/seasonal storage. Distinguishing between regions based on seasonal peak heating is an important factor in evaluating the energy system challenge.

On the supply side, the variation in diurnal and seasonal VRES load factors will have a significant impact on power system configuration. Even if the cost of generation is low, large diurnal variation in output would tend to increase curtailment and require greater deployment of flexibility sources such as Demand Side Response (DSR), and batteries, to match demand. Similarly, significant seasonal variation in VRES load factors could result in extended periods of energy deficit, which would require increased use of dispatchable sources such as biofuel, and/or seasonal storage. Distinguishing between regions based on VRES load factors is important in evaluating the supply challenge.

A third aspect is the availability of gas networks to carry decarbonised molecules to customers, as part of a potential solution to the above issues. A number of the scenarios we studied feature higher levels of molecules, and for those scenarios we link the deployment of hydrogen (H_2) for heating with the extent of gas networks in each country. The availability of these networks to carry the molecules to customers is also an important driver for configuring zero carbon energy systems.

ZERO CARBON SCENARIOS

A scenario-based approach is used in this study because it allows us to explore the true dynamics, interactions and implications across the multi-vector system of distinct scenario choices, particularly around end-use technologies. The approach is preferred because alternatives such as whole system optimisation would choose a single, "optimal" configuration, but it would not be clear how sensitive the system configuration would be to changes in inputs. In our approach there is no guarantee that the systems are "least cost", but there is extensive sub-system optimisation[1] in the modelling, and the approach allows deeper insight into the robustness of system configurations.

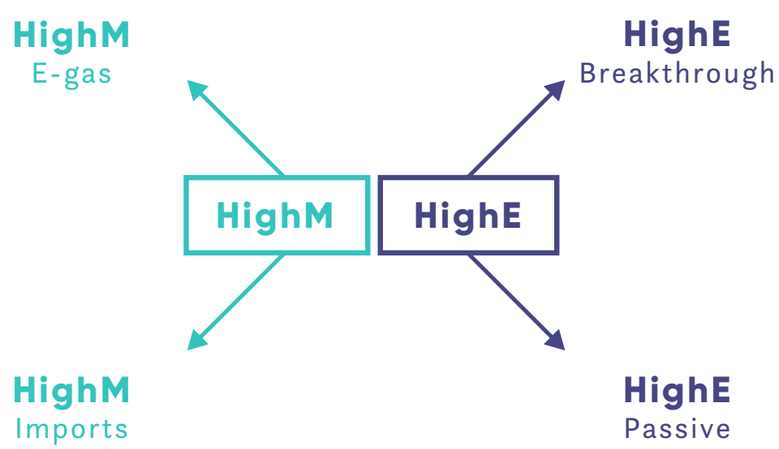


FIGURE 1: *Scenarios studied in this report*

The configuration of scenarios is shown above. The first three core scenarios are on the right hand side and feature "high electrification of demand". These explore how the system would respond to variations on the demand side, such as deployment of grid-responsive smart-demand, and the level of energy efficiency improvements, mainly in space heating.

Scenario High Electrification (HighE): this is a central case, identifying the implications of combining smart integration of primarily electric heating and transport and electrification of industrial processes, with VRES. The scenario includes intermediate efficiency savings; demand side flexibility (from controlled EV charging, grid responsive electric heating), network battery storage to balance daily variation, using hydrogen as a seasonal energy store (via electrolysis and H2 gas turbine electricity regeneration). This has similarities to the European Commission's 2018 Long Term Strategy (LTS) ELEC scenario.

Scenario HighE-Passive: explores the cost of no- demand side smartness, and limited efficiency improvements; the result is an increase in peak and overall energy demands on the power system. This scenario can be interpreted as a failure to engage the demand side in contributing to the balancing of the power system. This has similarities to the 'no gas' electric counterfactual scenario used by Ecofys/Navigant in their 2018 ''Gas for Climate'' report.

Scenario HighE-Breakthrough: this explores the whole system benefits of demand engagement. It is based on the HighE scenario, but with deeper levels of thermal fabric efficiency to reduce heat demands and increase viability of heat pumps in the stock (both for buildings and for district heating networks). The scenario also includes vehicle to grid as a flexibility technology, where EVs can export electricity back to the grid and support the power system. This has similar features to the LTS EE scenario.

The three scenarios on the left-hand side of Figure 1 explore alternative futures where electrification of energy demand is more moderate and complemented with a higher amount of green molecules in end-uses. The choice to explore green hydrogen as an alternative energy vector to electrons reflects the state of the current policy debate which sees sector integration and Power-to-Gas solutions like green hydrogen and e-gas playing a major role in the energy transition going forward.

Scenario High Molecules (HighM): this explores the potential for green molecules to support the power system in alleviating key power system stresses. Green molecules are the predominant means to deliver heating energy to customers, where gas networks are available. There is also greater deployment of fuel cell cars and trucks compared to HighE. This has similarities to the LTS H2 scenario.

Scenario HighM-E-gas: based on HighM, this explores the implications of converting hydrogen to synthetic methane as a way of transmitting molecular energy, avoiding H2-proofing upgrades to the gas grid. Green hydrogen (as in HighM), and CO2 from Direct Air Capture, are combined in a Sabatier process to generate synthetic methane. This has similarities to the LTS P2X scenario.

Scenario HighM-Imports: this explores the system benefits of importing hydrogen from cheap renewable sources outside Europe. This reduces generation capacity requirements within Europe and saves on some gas related infrastructure costs. Some adverse macroeconomic implications associated with greater reliance on fuel imports may be expected.

ALTERNATIVES: SUPPLY SIDE

Many studies assume that Carbon Capture and Storage (CCS) will become available and they predict that in such circumstances, "blue" hydrogen (created from fossil fuels but with the carbon abated via storage), could generate hydrogen at a lower cost than the "green hydrogen" from renewable electricity sources evaluated in this study. There is however great uncertainty around the costs associated with CCS, as the technology remains largely untested. This report builds on a growing body of literature that suggests electrolysis, used for the production of green hydrogen, will see significant cost reductions, particularly when deployed in power systems with high VRES penetration and with associated curtailment and low electricity prices [2].

Furthermore, it is important to recognise that decarbonisation pathways that rely on CCS do still feature a small share of residual CO2 emissions, unless low carbon biomass (a scarce and valuable resource) is used as a fuel. Blue hydrogen would furthermore include a continuing reliance on natural gas supply chains which are prone to methane leakage[3]. The scenarios in this report therefore focus on the challenge of ensuring power system adequacy where decarbonised electricity is provided primarily from VRES. Dispatchable power sources, such as biomass, and hydrogen-fuelled gas turbines (H2GT), are used only when VRES sources are insufficient to meet demands, after other sources of flexibility are used up (such as DSR, interconnectors, hydro, storage).

ALTERNATIVES: DEMAND SIDE

The scenarios explore the whole system implications of either: primarily electrified heat (via local and district heat pumps and resistance heating) or heat delivered primarily via green molecules (where gas networks exist to deliver these molecules). We acknowledge that there are many more heat-delivery options that we can explore in this study, and there is the potential for some of these to alleviate some system challenges and have aspects that perform better that the options in this study. A potential technology candidate is the use of hybrid heat pumps, which for most of the year use decarbonised electricity but, at power system peaks, transition to consume gas. A second alternative is micro combined heat and power (fuel cell or other).

1.2 COUNTRY ARCHETYPES

This study is pan-European in scope. To evaluate distinct conditions across Europe, we take an archetype approach to evaluate distinct sets of energy demand, energy supply and gas infrastructure availability, all of which strongly influence the configuration, performance and cost of zero carbon energy systems.

Using heating degree days, member states are arranged into three groups, and these are used to assign the distribution of heating technologies in the HighE scenarios. For the HighM scenario, the extent of the gas network is used to arrange member states into three groups and assign gas and electric heating technologies to each of these. In addition, the seasonal load factors for wind and solar energy were evaluated for all member states, and countries were grouped into wind-dominant or solar-dominant countries. This approach allows six different regions to be identified based on combinations of heating demand with different supplies of variable wind or variable solar pv power.

From each group a single country is used to represent the conditions that pertain to that group. The countries evaluated as archetypes are Spain, France, Germany, Poland, Hungary and Bulgaria.

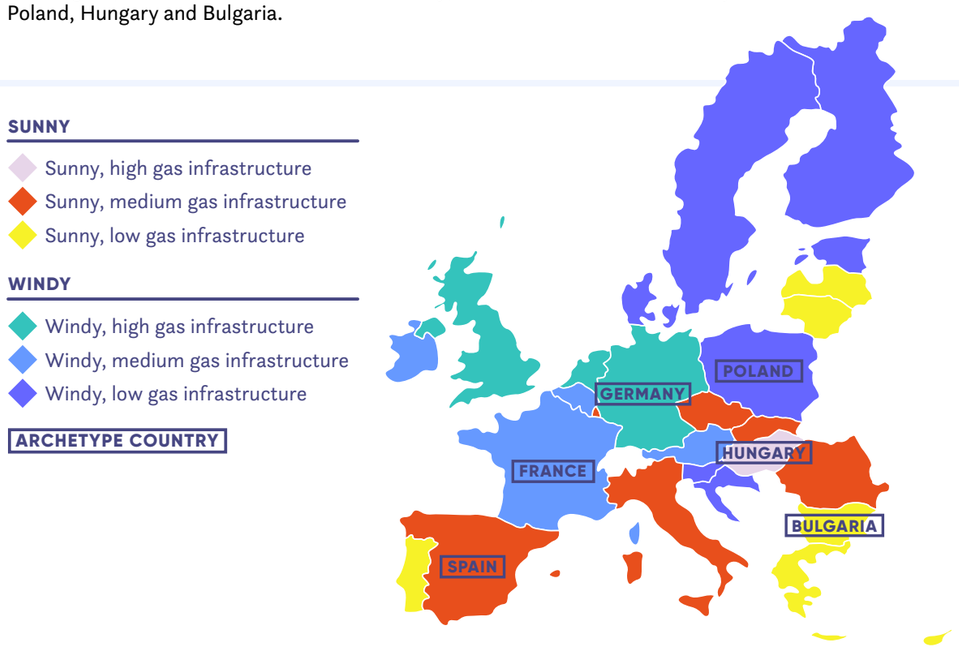


FIGURE 2: *Country archetypes used in the study*

1.3 TECHNOLOGIES

The European building stock model is based on the European Building Stock Observatory. The stock model includes a definition of the fabric efficiency of each building and is used to determine the performance and cost of fabric improvements, as well as to size the heating systems.

Heating technologies include heat pumps, at building level and for district heating systems. The coefficient of performance (COP) for air source heat pumps varies with outside air temperatures, and approach lowest levels in cold weather. District heat pumps are ground source and so COP does not vary. Direct electric heating is also deployed.

All electric heating technologies can provide some degree of flexibility. Large-scale district heat pumps have the greatest provision of within-day flexibility, because thermal storage is included. Small thermal stores in houses also allow some flexibility from residential HP. Thermal storage in resistance heaters also provides within-day flexibility.

Interconnector capacities are set using the EU Commission's 2017 report on electricity interconnection, which targets a lower bound of 30% of peak load in each country. While interconnection levels up to 60% are recommended in the long term, we used the lower value to account for the fact that interconnectors are - in our model - only used in times of peak demand. In these hours the full interconnector capacity might not be available as peak demand and RES generation in neighbouring countries are closely related.

Industrial electrification is assumed to occur in alignment with the Eurelectric decarbonisation pathways report (Nov 2018). We further assume that 10% of industrial demand can be shifted to other times within the day.

Biomass is used for heat and power generation. Biomass availability is based on the Ecofys/Navigant 2018 "Gas for Climate" report. More recent analysis by the ICCT[4] however suggests the sustainable biomass potentials in the EU for use in heating, power and transport are significantly lower and so preference may need to be given to a greater reliance on green hydrogen, heat networks or direct electrification.

Figures for Electric Vehicles (EV) and Fuel Cell (FC) uptake in passenger cars and Heavy Goods vehicle (HGVs) are taken from the ECF "Fuelling Europe's Future II" study. For the HighE scenarios, 78% of cars are Battery Electric Vehicles (BEV), the remainder being fuel cell. In the HighM scenarios, 46% of cars are FC.

1.4 WHOLE SYSTEM MODELLING

The main principles of whole system operation are summarised here; a more complete description of the model is provided in the appendix.

The starting point is the set of hourly energy demand profiles for each sector. For heating, these demands are based on the building heat loss, heating technology and outside air temperatures. Weather data is taken from a 1-in-20 year cold period. Some demand profiles are fixed (no flexibility), while others are able to be shifted over defined periods.

Transport demand is based on the stock of electric vehicles, their efficiency, the daily usage, and arrival/departure times from home and work to generate baseline electrified transport demand. Grid-responsive smart charging can schedule charging to times of most use to the grid, while still providing vehicles with sufficient charge for transport.

Country-specific hourly weather data is also used to generate hourly load factors for wind and solar production. An initial specification of the VRES generation fleet is used and combined with the demand data to generate initial net load curves.

Demand shifting is deployed to minimise net demand and, therefore, minimise generation curtailment. Network capacity is adjusted to optimise between demand driven and network curtailment. The dispatchable generation fleet is then deployed in merit order to fill in the supply gap. Remaining unmet demand is supplied by seasonal storage, and generation capacities are updated to reflect this.

Once all hourly demand is met, annual system performance metrics are evaluated (CO_2, limits on biomass use) and generation inputs adjusted to meet targets. Final outputs are generator capacities, network capacities, electrolyser capacities, storage, and H2GT capacities, and associated costs.

1.5 MACROECONOMIC MODELLING

The macroeconomic analysis was carried out using the E3ME[5] global macro-sectoral model, which has been designed to model the economic impacts of long-term energy-economy-environment scenarios.

E3ME models the links between the energy system, the environment and the economy. Changes in the energy system feed into the economy via changes in energy prices, energy use, the energy generation mix and the demand for carbon-based or clean technologies. Industries and consumers respond to changing prices, which leads to changes in output and incomes across different regions and sectors. The E3-linkages support the modelling of scenarios that capture the potential economic impacts and transition risks associated with a range of policies, to a high degree of geographical and sectoral detail.

In the scenarios modelled in this study, the outcomes from the energy system modelling (in terms of investment spending in different kinds of technology and use of the different energy carriers) are introduced into E3ME, and the implications for the costs faced by energy users are calculated. The net effect on GDP, jobs, prices, incomes and spending then follow. They are reported as differences from what would be expected in 2050 under 'current policies'[6].

2

ENERGY SYSTEM IMPLICATIONS

The outputs from the energy system model are presented in this chapter. As introduced above, the analysis took the approach of evaluating a number of distinct country-archetypes. When presenting the results below, we have focussed on two distinct country archetypes: one representing the colder Northern European climate (like Germany) and the other a milder Mediterranean climate (like Spain). These are most instructive, because differences in demand patterns (such as a marked seasonal heating signal in Germany) and supply (PV load factors higher and more constant across the seasons in Spain[7]) strongly influence the outcomes from the energy system models. Results from the other four archetype countries studied (Poland, Hungary, Bulgaria, France) lie within the range set by the Germany and Spain models.

The overall results for archetype Germany are shown below. Six scenarios were run in total, three variants of HighE and three of HighM. The annual cost of each scenario is presented; this includes operational costs as well as annualised capital investments. The figure highlights the distribution in costs by level in the energy system (Generation, Infrastructure, and Demand side), and provides a further breakdown below these levels.

What we see is that the High E–Breakthrough scenario comes out as most attractive, with an overall annual system cost of approximately €114 billion as of 2050. Three features characterise this scenario from an energy system perspective. These are explored in the following sub-chapters.

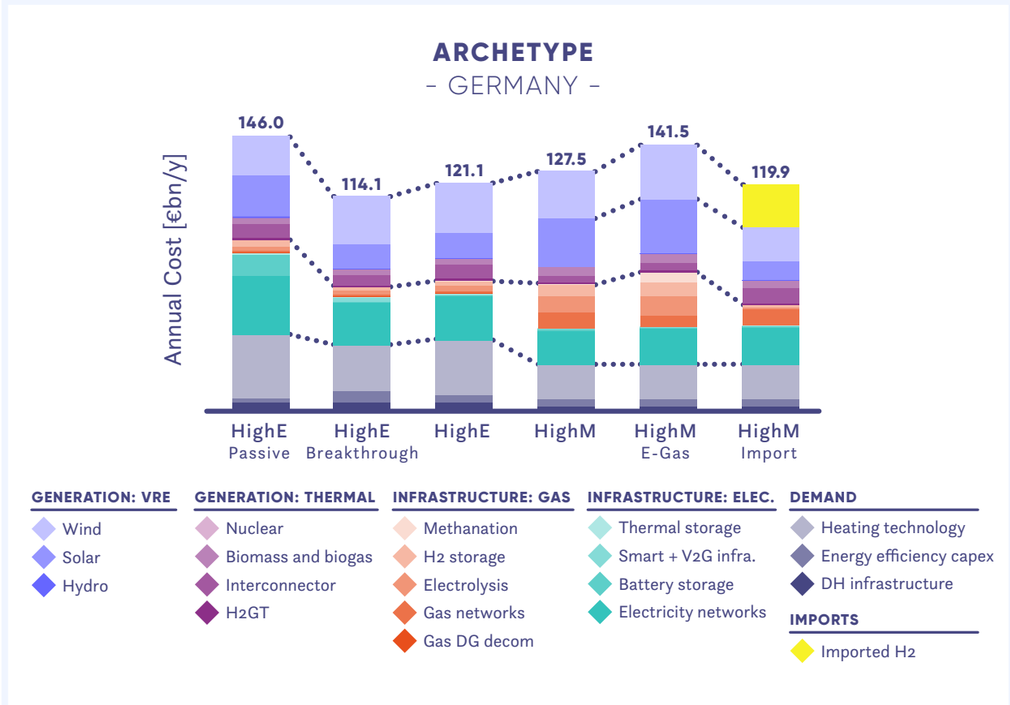


FIGURE 3: *Scenario comparison of whole system costs for archetype Germany*

2.1 BUILDINGS EFFICIENCY – REDUCING THE HEAT DEMAND PEAK IN BUILDINGS COMES WITH SUBSTANTIAL ENERGY SYSTEM BENEFITS

The HighE-Breakthrough scenario analyses how the whole energy system would perform following deep thermal renovation of buildings. It also uses the 2050 EV fleet for vehicle to grid applications. As with all of the HighE scenarios, heat is delivered primarily through heat pumps, some direct electric heating, and a significant portion through district heating (large-scale centralised heat pumps). One advantage of district level heat pumps is the storing of hot water which introduces significant daily demand side flexibility into this sector of heat delivery.

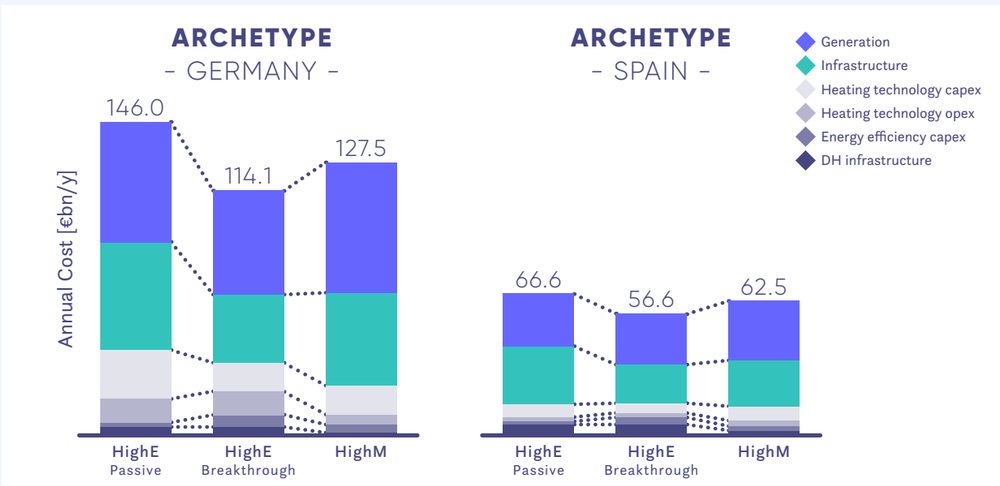


FIGURE 4: *Whole system cost comparisons: archetypes Germany and Spain*

Figure 4 shows the capital costs associated with building fabric thermal retrofit, the capital costs associated with heating technology, and the operational costs for heating systems (non-fuel) as well as infrastructure and generation level costs. All costs are annualised. Compared to HighE-Passive, in the HighE-Breakthrough scenario, (annualised) capital costs of electric heating technologies are reduced by 40%, from € 22 billions to €13 billion (smaller heating systems can be deployed). Also fabric efficiency reduces the heat loss rate to buildings, which improves the efficiency of heat delivery (COP of heat pumps).

Overall, we found the HighE-Breakthrough scenario to deliver the lowest overall system cost, out of the scenarios studied for archetype Germany as well as the second lowest cost for archetype Spain, at €114 billion per year and €56 billions per year respectively. This marks a 22% reduction in cost in archetype Germany (15% for archetype Spain) when compared to a passive energy system, and an 11% (9% for archetype Spain) reduction compared to the scenario with a higher reliance on molecules. Energy efficiency measures do come at a significant investment, but they reduce operating costs (fuel bills). Whether there is a net cost or saving between these two factors depends on the country archetype and heating system, but broadly the balance between these reflects the marginal economics of deep efficiency investments recuperated through energy savings alone. However, also notable is the significant saving in infrastructure that efficiency delivers. The peak demand in HighE scenarios is dominated by heating, and reducing this peak heating load through deep energy efficiency reduces infrastructure costs. This saving in electricity infrastructure, facilitated by energy efficiency, should be acknowledged, and a means found to remunerate customers for these avoided system costs.

2.2 CLEAN ELECTRICITY AND SMART FLEXIBILITY - A SELF-REINFORCING DYNAMIC

DEEP DECARBONISATION AND MANAGEMENT OF NET DEMAND

Most electricity generation today is thermal-based, which means the generation fleet can flex up and down in response to the level of consumer demand. Typically, the cost of energy increases at times of peak demand, while electricity infrastructure must also be sized to meet peak demand.

Future electricity systems which have been decarbonised with Variable Renewable Energy Sources (VRES) will operate very differently. Due to the variability of supply, zero carbon electricity systems will experience many hours of the year when energy supply will exceed hourly demand. This is a continuation of a trend already observed in some EU Member States which have high levels of VRES penetration; thermal generation is turned down to accommodate high levels of VRES, and/or the VRES output is curtailed off either because of limited demand or limited network capacity to carry electricity to end uses.

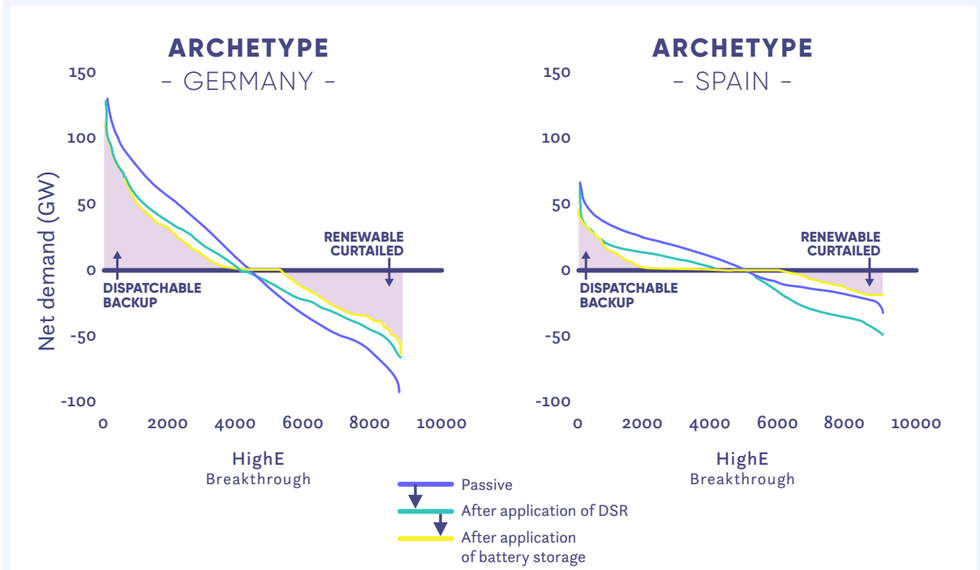


FIGURE 5: *Net demand graphs comparing the relative impact of demand side response and battery storage for archetype Germany (left) and Spain (right) – HighE-Breakthrough*

Increasingly, the electricity system will move from responding to demand, to responding to the net demand – the residual demand after VRES generation is included. The graphs above are yearly net demand curves for two archetypes. The hourly data is arranged from hours of largest positive net demand to minimum net demand. In the upper portion of the graphs, the challenge is to ensure security of supply during the hours of largest net-demand (left side) and to minimise the requirement for dispatchable low carbon generation (such as flexible hydro, biogas generation, H2GT, or interconnectors) to fill the supply gap. When the net demand is negative (excess VRES – visualised on the right side of the graphs) the challenge is to limit the wasteful curtailment of VRES by shifting loads into these periods.

Demand side response and battery storage are technologies able to achieve such load shifting and thereby reduce both positive and negative net demand as displayed in the graphs above. The resulting outcome of battery storage and DSR combined is that net demand is reduced by 44% (from 408 TWh to 229 TWh) in archetype Germany and by 70% in archetype Spain (from 217 TWh to 65 TWh). Subsequently, thermal backup capacities are reduced by 38% (from 162 GW peak to 100 GW peak) and 54% (from 78 GW peak to 36 GW peak) respectively.

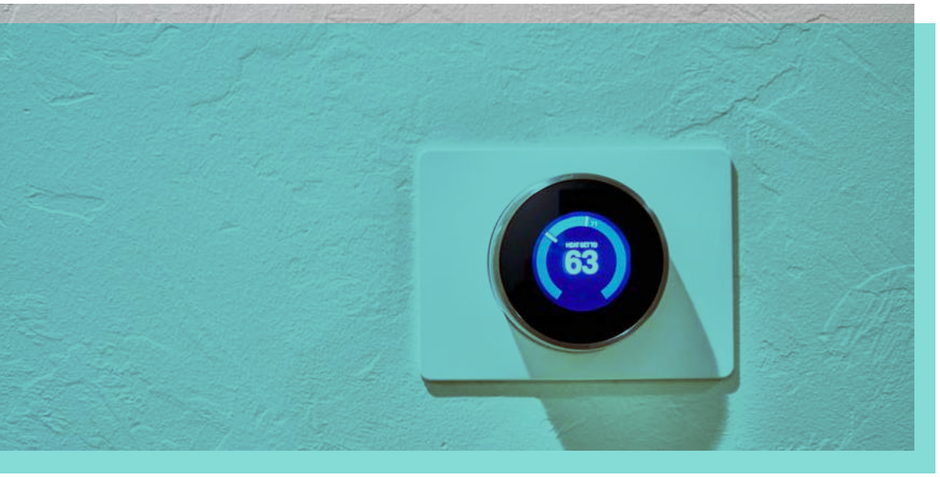
THE BENEFIT OF DAILY DEMAND SIDE RESPONSE

Demand Side Response shifts electricity consumption to periods of time when that demand can more easily be accommodated by the system. The DSR sources in the model are:

1. Baseline appliance and process demand in residential, commercial and industrial sectors, where 10% of daily electricity demand is shiftable through the day
2. Residential electric storage and district heat pumps, where 100% of daily demand is shiftable within a day due to thermal storage.
3. Residential heat pumps, where a fixed amount of thermal storage permits some flexible operation.
4. Smart EV charging, where specific charging windows for residential and work charging are used.
5. Vehicle to grid – permitting regeneration of electricity from vehicles back to the grid at times of negative net demand (HighE-Breakthrough).
6. Hydrogen demand, which can be shifted throughout the year and stored in seasonal stores.

Traditionally, DSR moves demand out of peak demand times. But in grids with significant VRES, DSR will also need to move loads into periods of high VRES output to reduce curtailment (subject to network constraints). Both actions have the effect of "flattening" the net demand curve, as can be seen in the Figure 5 above. The result of daily DSR is:

- Reduced annual dispatchable capacity requirements by 24% and 33% (archetype Germany and Spain).
- Reduced curtailment by 33% and 47% (archetype Germany and Spain).



DAILY ELECTRICITY STORAGE VITAL TO SUPPORT HIGH LEVELS OF VRES

In addition to the above flexibility provided by DSR/smart charging, battery electricity storage is also included in the model. The deployment of battery storage in each scenario is limited to an economic threshold. The threshold is set at the level of GWh battery deployment that achieves 150 cumulative full charge/discharge cycles per annum. This threshold is based on projections of 2050 battery storage cost and the revenues that could be generated from daily electricity arbitrage. The storage size is dynamically derived from the net demand profile and so varies per scenario. 150 cycles require the battery to be utilised quite frequently, for example requiring relatively significant depth of discharge on a near-daily basis. Battery storage is deployed after DSR has flattened the net demand curve.

As Figure 5 shows, battery storage is very effective in flattening the net demand curve, but the impact is most marked in sunny countries such as the Spain archetype displayed. There is a strong positive relationship between battery storage deployment and PV deployment in sunny countries; the battery can reduce daily curtailment of peak PV energy output, regenerating back to the grid in evenings/overnight; while the regular diurnal output of PV helps batteries achieve the annual cycles required for economic viability and thus increases economic storage deployment.

EVS WILL REPRESENT A HUGE LATENT STORAGE ASSET

In the HighE-Passive scenario, electric vehicle charging is unmanaged: charging begins when the vehicle arrives at work, or at home, and continues until the vehicle is full. In the DSR scenarios (HighE) EV charging is grid responsive, shifting (within constraints) to times that flatten the net demand curve. The HighE-Breakthrough scenario takes this further and allows EVs to send electricity back to the grid (V2G), and in doing so, the EV fleet acts like a battery asset, albeit with constraints related to vehicle utilisation, charging location, etc.

The cumulative storage capacity represented by a 2050 EV fleet is very large, as can be seen in Figure 6. This compares the GWh storage capacity in grid batteries with that represented by the EV fleet, which is 50 times greater. Note that the x-axis is logarithmic. Notwithstanding challenges around infrastructure cost, consumer behaviour, and impacts on vehicle battery degradation, there is enormous potential in the EV fleet to flatten the net-demand curve and this source of flexibility should be exploited where feasible to do so.

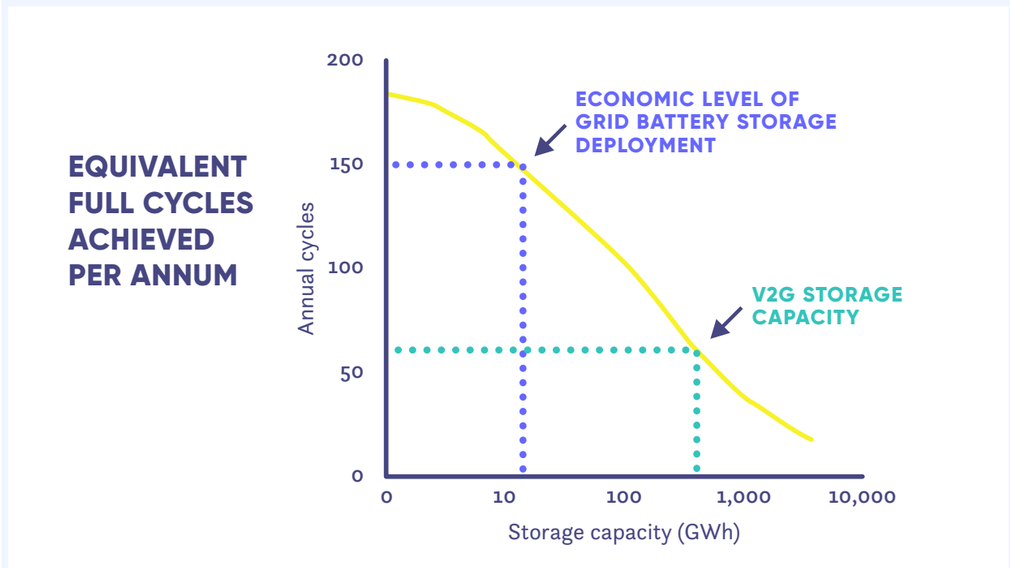


FIGURE 6: *Increased deployment of storage leads to reduction in average utilisation*

DEPLOYING FLEXIBILITY AT SCALE

DSR, utility-scale grid batteries, smart EV charging and V2G are all sources of flexibility that decarbonised grids will require. While each resource will have unique capabilities and constraints, they will all have a common objective, to flatten the net demand curve, and there will be competition between them. HighE-Passive requires a very large deployment of grid batteries (900GWh in archetype Germany, 600GWh in archetype Spain), to overcome the lack of flexibility in demand in this scenario. By introducing flexibility in HighE, the required battery storage capacity drops significantly, and in HighE-Breakthrough, which also has V2G grid-battery storage deployment is significantly reduced (in many archetypes) because so much flexibility is provided by the large V2G EV fleet[8].

There is also competition within each type of flexibility technology. The analysis shows that, as increasing storage volumes are deployed, the utilisation rate (marginal value) decreases. (Figure 6). This presents a challenge to sustained deployment of storage, because later deployments reduce the average annual cycling (revenues) of the battery fleet. However, there is a positive synergy between the deployment of storage capacity and increased uptake of VRES to decarbonise energy systems. Higher VRES deployments tend to increase the mismatch between supply/demand, and greater battery energy capacities can be economically deployed to flatten the net demand curve. Continued deployment of VRES in line with decarbonisation targets will support the deployment of flexibility solutions such as batteries. This is an essential part of the self-reinforcing dynamic between greening electricity and smartening demand flexibility.

Image: Hannes Flo "Copenhagen" (CC BY 2.0)

2.3 LONG-TERM STORAGE – CRITICAL IN COLDER CLIMATES AND A POTENTIAL KEY ROLE FOR GREEN HYDROGEN

HOW LONGER-TERM STORAGE ENABLES VRES

The electricity storage sector is growing rapidly. As costs reduce, the expectation is that storage can transition from providing high specific-value, frequency regulation services (typically requiring storage duration times of an hour or less) to the gradual replacement of peaking power plants, as economic storage durations increase to multiples of hours. Grid storage in this model relies on revenues from energy arbitrage, and requires relatively high (near daily) cycling to be economic, which firms up PV energy extremely well, and also supports firming up of wind (but to a lesser extent, given wind output varies over longer timescales). Further cost reductions of storage technologies could allow economic deployment of longer-duration batteries (weeks) and this would be an enabler mostly of wind.

However, in zero carbon systems, a key challenge is seasonal security of energy supply. This is because in colder climate countries with a strong seasonal pattern of demand (notably for heating), there will be extended periods of time where there is insufficient (variable) renewable energy available, leading to a net energy deficit extending to periods of a month or more. Attempting to reduce this window by introducing higher capacities of renewables is hugely inefficient economically because it leads to high levels of curtailment in other seasons. Some form of storage will therefore be required to enable these higher, seasonal demands to be met.

In our model, we offer the system to use hydrogen as an energy storage carrier. It is generated, via electrolysers, initially from VRES which would otherwise be curtailed. This is available to be used in hydrogen gas turbines to generate zero carbon electricity at peak times; depending on the scenario it is also used in fuel cell cars, and in boilers for heat.

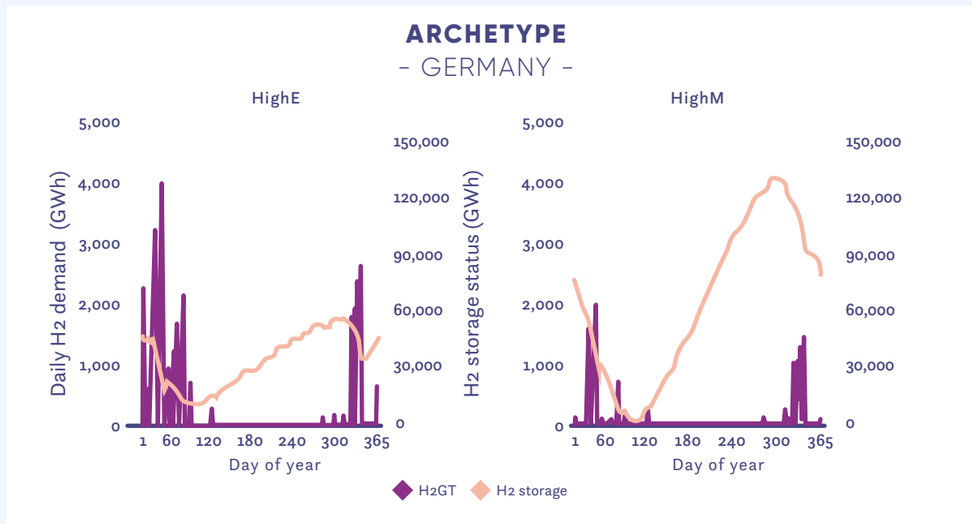


FIGURE 7: *Annual H2 store status and use of H2GT to provide grid support (archetype Germany)*

The status of hydrogen stores in the Germany archetype is shown in Figure 7, for HighE and HighM. In both scenarios, we see the store is filling for just over half the year, and discharges during the winter heating period. The store reaches a maximum of 45 TWh in HighE, and reduces when H2GT capacity is required (mainly to support peak heat pump loads)[9]. H2GT capacity is required intermittently over the heating period, with a total installed capacity of 79GW.

The H2 store capacity in the HighM scenario is larger at 130 TWh, because there is a larger share of continuous demand of hydrogen for cars and trucks and also a share of hydrogen being fed into the gas network for heating, compared to HighE scenarios. In contrast, the H2GT peaking requirements are much lower; H2 heating reduces peak electrical load from heat pumps, and the H2GT capacity is reduced to 44 GW and the utilisation of this fleet is lower than the H2GT fleet in HighE.

Equivalent data for the Spain archetype is shown in Figure 8 below. H2 is still required annually to support fuel cell vehicle demands and some H2 heating. A key distinction compared to archetype Germany is that in neither scenario is H2GT capacity required for archetype Spain. This is mainly due to the lower heating demands, which means seasonality of demand is lower.

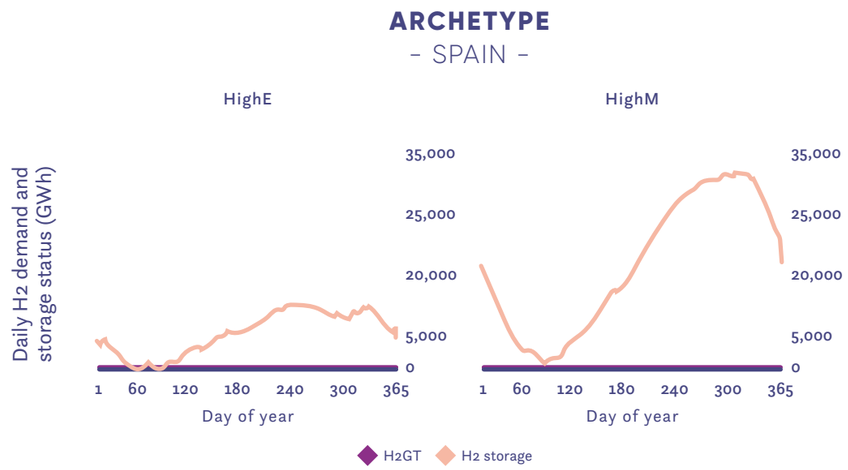


FIGURE 8: *Annual H2 store status and use of H2GT to provide grid support (archetype Spain)*

The analysis indicates that seasonal storage is a vital element of electricity systems where demand is highly seasonal in nature, mostly dictated by residential heat demand. To avoid stalling the fight against climate change, policy should be directed at encouraging the next wave of long-duration/seasonal energy storage technologies that go beyond lithium. As seen in this study, green hydrogen could come in to play this role, but other suitable alternatives may yet emerge.

It should be noted that the HighM scenario would require ca 1000 GW of electrolysers to operate across Europe in 2050. In the HighE scenario that is over 350 GW, still a step-change from the 8GW electrolysers in operation today.[10]

SYSTEM IMPACTS OF GREEN MOLECULES

One of the widely accepted advantages of using green molecules for heating (via boilers) instead of electricity (in heat pumps) is that energy delivery via molecules removes load from the power system times of peak system demand, and this reduces peaking plant requirement. The variation in H2GT power requirements in Figure 7 show this is the case for countries with a strong seasonal heating demand signal.

In addition, a further advantage of HighM is that it can reduce the investment in heating systems. The graph below compares the annualised system costs of two countries, for HighE and HighM, comparing the costs incurred at each level in the energy system. HighM shows a significant saving is generated within the household, due to the lower projected cost of installing and maintaining hydrogen boilers compared to heat pumps. The effect is more marked in archetype countries with a larger seasonal heating signal. This saving at the consumer level is important to recognise, given that incentivising consumers to adopt low carbon heating technologies has proved challenging.

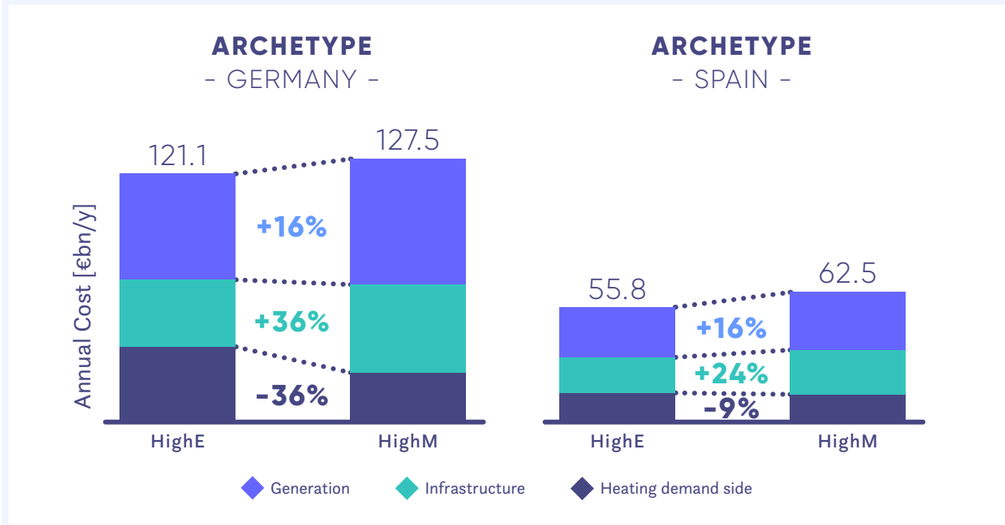


FIGURE 9: *Comparing system costs in HighE and HighM scenarios, archetype Germany and Spain*

That being said, while peaking plant requirements are lower in HighM than in HighE, our analysis does find that overall there is additional investment required at generation level. This is because more electrons must be generated to offset the losses in electrolysis, the lower efficiency of heat delivery of boilers compared to heat pumps (when including temperature varying COP), and in fuel-cell compared to battery-electric vehicles. The overall increase in cost at generation level is ca. 16%. The change in annual energy requirements in the HighM scenario can be seen in the graphs below. Note that the increase would not be so marked if H2 was used solely for seasonal storage for H2GT because a greater proportion of the electrons required would come from VRES that would otherwise be curtailed.

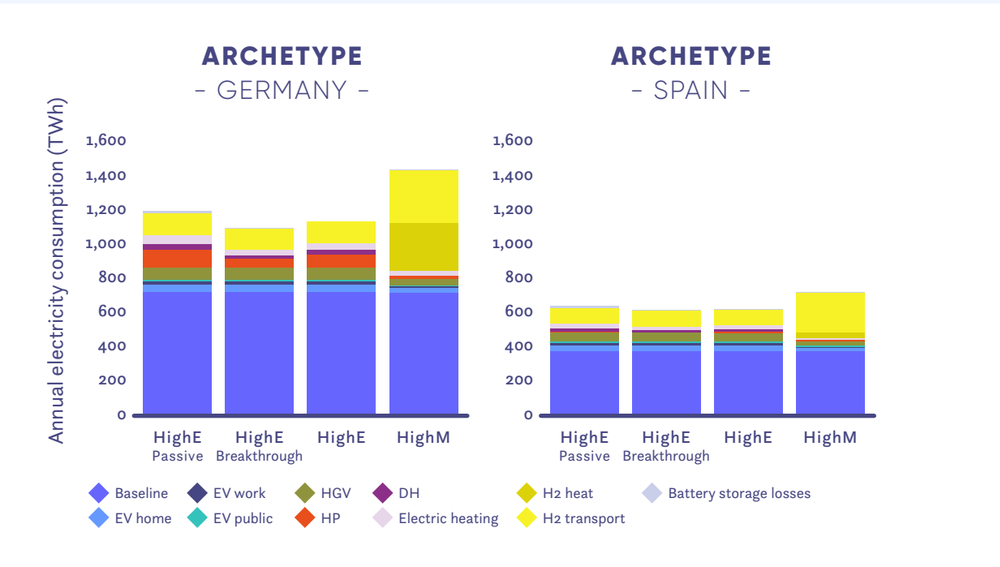


FIGURE 10: *Annual electricity consumption across scenarios: archetypes Germany and Spain*

The HighM-Imports scenario was developed in part to address the issue of additional electron demand in HighM, by exploring options for importing green H2 from outside of Europe. We found that the HighM–Imports scenario reduced generation capacity by 50% compared to HighM. Also there is a significant saving on infrastructure costs, because electrolyser costs are avoided. These sources of savings are transferred to an annual fuel import cost, and the macroeconomic implications of this are explored in the next chapter.

DECARBONISED GAS INFRASTRUCTURE

Our modelling shows that while the HighM scenario reduces the investment required in electricity networks compared to HighE by up to 22% in archetype Germany, these savings are outweighed by additional gas infrastructure costs. In the HighE scenarios, we find that most of the distribution gas network can be decommissioned, whereas in HighM it needs to continue to be maintained and this brings associated costs (as do electricity networks). In addition there is investment to make the gas network H2 proof and there is more investment required in electrolysis and storage.

The net result is a significant increase in the gas components of infrastructure, which drives an overall increase in system cost.

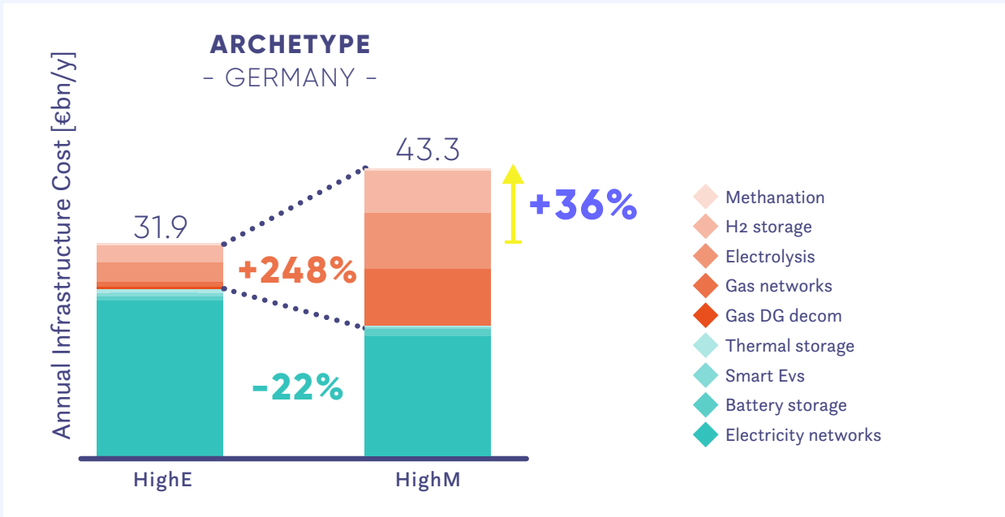


FIGURE 11: *Infrastructure investments in HighE and HighM*

E-GAS

This scenario evaluated the potential gas infrastructure savings that would arise through use of synthetic methane (e-gas) derived from green hydrogen - rather than using the hydrogen directly - as the carrier for delivering a significant amount of energy in the HighM scenario.

CO_2 is sourced from direct air capture and combined with H_2 in a Sabatier process to produce (synthetic) methane, or e-gas. Avoiding "H_2-ready" gas network investments does reduce gas network costs by 27%, but there are additional costs of methanation, and the additional energy losses require greater investments in electrolysis and storage. What we see therefore is that the overall system cost of the e-gas pathway would result in a 15% increase in annual infrastructure costs (€ 49,6 bn/year) over the green hydrogen pathway (€ 43,3 bn/year).

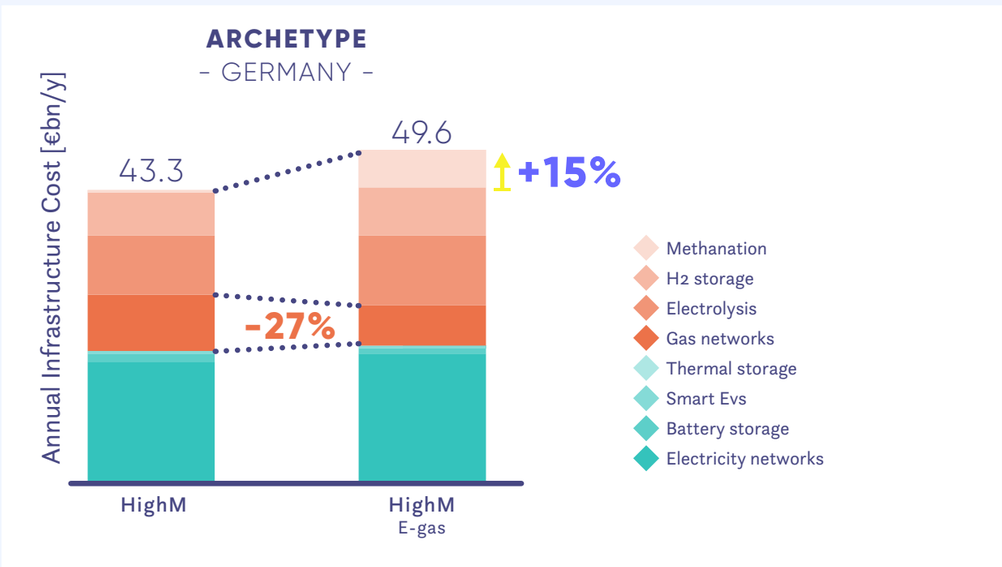


FIGURE 12: *Infrastructure costs, HighM versus HighM-E-gas*

2.4 INVESTMENT IN ELECTRICITY INFRASTRUCTURE KEY TO ALL SCENARIOS

While using molecules as an energy carrier does reduce the investment required in the electricity grid, we found that all scenarios required a significant increase in network capacity, compared to today.

As Figure 13 shows, the HighE scenario requires electricity network capacity to more than double from today's capacity. HighM limits this to an increase of 64%, but this still represents a significant expansion in order to accommodate the high degree of electrification of loads and an even greater amount of VRES capacities, by 2050. Continued investment in electricity system infrastructure is a no-regret option.

While the need to invest in electricity transmission infrastructure has been understood for some time, most of the required investment is at distribution level. While smart technologies will be deployed in the near term to make more efficient use of existing distribution network capacity, the critical need to continue to build distribution network capacity out to 2050 should not be overlooked if the grid is to be decarbonised. We note that short/medium term pressures on distribution system operators encourage the full utilisation of existing assets and avoiding investments; whereas the long term will require significant network expansion even in smart, highly responsive systems.

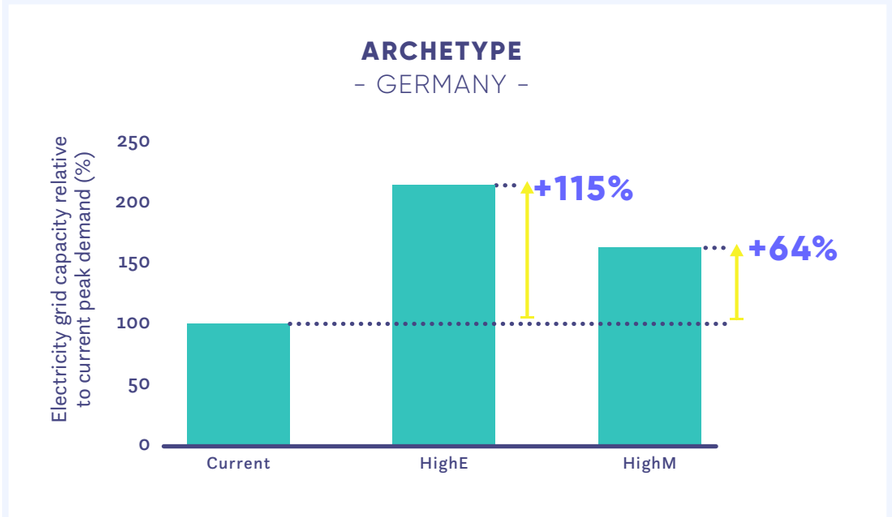


FIGURE 13: *Power system peak network capacity, archetype Germany*

3

MACROECONOMIC IMPLICATIONS

3.1

KEY DRIVERS OF THE MACROECONOMIC OUTCOMES

The macroeconomic impacts of the scenarios depend on two key drivers: (1) the net impact on annualised energy system costs, and (2) where the equipment and fuel are produced.

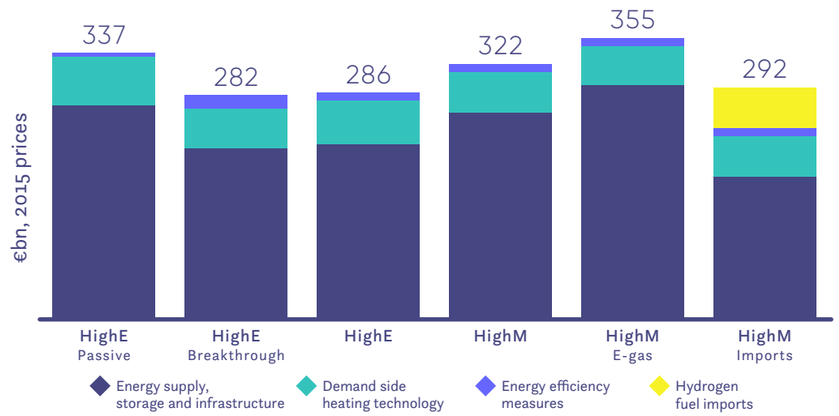
THE NET IMPACT ON ANNUALISED ENERGY SYSTEM COSTS: THE CENTRAL ROLE OF ENERGY SUPPLY COSTS

Decarbonisation requires a change in the way that we transform and use energy. Many of these changes involve spending more upfront on equipment and less on ongoing use of fossil fuels. This includes investing to make buildings more energy efficient, purchasing low carbon vehicles that have a higher capital cost but lower running costs, and generating power from solar photovoltaic installations and wind farms. This highlights the importance of the availability of financing for energy users, spending more on buildings and equipment, and energy suppliers, spending more on power plant, storage and infrastructure, to support the scaling up of upfront spending. From a policy perspective, this means addressing the informational and institutional obstacles to the development of suitable instruments to facilitate and de-risk project and household financial investment.

Some decarbonisation solutions are confidently expected to reduce costs in 2050 compared both with today and with a 'business as usual' carbon-dependent future. For example, there are still important opportunities to improve energy efficiency with a short payback period, notably in the housing stock. A larger global market for decarbonised technologies will justify further investment in R&D to accelerate technological progress and bring down costs, for example in power generation and road transport. Lower net costs of meeting the needs supplied by energy services release income for energy users which can be spent on other items, thereby generating jobs and income in the supply of those goods and services.

Other decarbonisation solutions are currently expected to increase costs. Although the costs of generating electricity using solar panels or wind turbines are expected to continue to fall, these intermittent technologies need additional capacity (which may be under-utilised at certain times of day / year) and storage (whether in the form of batteries, hydrogen or other synthetic fuels) solutions to meet time-of-day and seasonal peaks in demand. We assume that the cost of providing this additional capacity and storage has to be borne by energy users and is passed on in the form of higher electricity prices. Higher net costs of energy have the effect of diverting more spending from household consumption to investment, which may boost production, GDP and jobs in the short term, but must be paid for over the longer term.

The cost of energy supply (including storage and infrastructure) dominates the differences in the projected annualised costs of the energy system between the scenarios developed in this study. Figure 14 compares the annualised costs[11] for key elements of the energy system in 2050 across the six decarbonisation scenarios, aggregated over the six archetypes distinguished in Section 2.2 above. The figure shows that energy supply costs account for 75% or more of the annualised energy costs. The figure also shows that the differences in total annualised costs between scenarios are driven by differences in energy supply costs: while, for example, there is more energy efficiency investment in the demand-side breakthrough scenario, and this has important impacts on energy use, the scale of spending is small by comparison to the other costs shown in the figure.

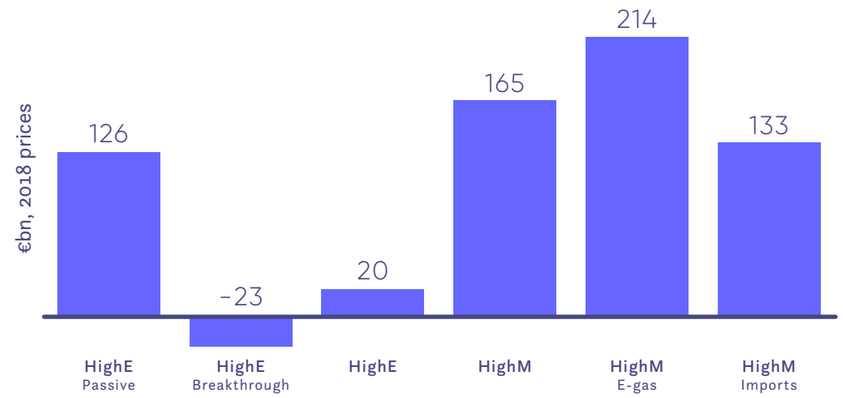


Source: Element Energy and Cambridge Econometrics

FIGURE 14: *Annualised costs in 2050 of key elements of alternative decarbonisation scenarios (total for six 'archetype' countries)*

Figure 14 also shows the ranking of each scenario with respect to these energy system costs. 'HighE' and 'HighE-Breakthrough' have broadly similar annualised costs. Energy system costs are higher in the 'High M' and 'HighE-Passive' cases (respectively 12% and 18% higher than HighE), and highest of all in the 'HighM-E-Gas' case (24% higher than HighE). Importing green hydrogen from abroad could reduce the energy system costs compared with domestic green hydrogen production.[12]

Figure 15 shows the impact in 2050 of the different scenarios on household energy[13] costs.



Source: Element Energy and Cambridge Econometrics

FIGURE 15: *Impact of the scenarios on household spending on energy, 2050*

The graph shows important differences between the scenarios with only the HighE-breakthrough scenario lowering energy expenditure for families. Energy costs – including the fuel cost and the extra cost of household heating equipment – are highest in the HighM and HighM-E-Gas scenarios, absorbing an additional €165-214 billion (0.9-1.2% of disposable income) in 2050, reflecting the costs both of hydrogen as a fuel and hydrogen boilers. Energy costs are also high in the HighE-Passive scenario because the electricity price in this scenario reflects the high cost to the electricity system of satisfying unmoderated peak demand.

Both the HighE and HighE-Breakthrough scenarios benefit from demand-side management which reduces electricity system costs. In addition, the HighE-Breakthrough case has investment in energy efficiency measures[14] in households, which both reduce energy demand and allow households to economise on the size of heat pumps, so that energy expenditure is €23 billon lower than in the 'current policies' REF2016 case.

WHERE THE EQUIPMENT AND FUEL IS PRODUCED: THE MACROECONOMIC IMPACT OF DEPENDENCE ON IMPORTED FUELS

The second key driver of differences in macroeconomic outcomes is whether the production of equipment and fuel takes place in Europe or not. A 'business as usual' carbon-dependent future for Europe would involve heavy dependence on imports of fossil fuels, with implications for both energy security (given the global concentration of sources of supply) and for Europe's balance of trade. A move to replace fossil fuel imports by green hydrogen imports would maintain this dependence and, since the hydrogen would cost more than the fossil fuel it would replace, it would increase Europe's import bill.

The other scenarios offer the prospect of the substitution of fossil fuel imports by equipment and fuel produced at least partly in Europe. The assumption made in the macroeconomic modelling is that the supply chains and import content that currently characterise the power supply and other engineering products used in Europe would continue in future, with the result that the annual energy spending in these decarbonised futures has a much higher European content, and so stimulates production and jobs in Europe. To the extent that the scenarios require different technologies to those used currently, this highlights the importance of competitive European suppliers in these technologies.

3.3 MAIN FINDINGS

Table 1 shows the outcome for selected macroeconomic indicators for the EU28 as a whole under the six decarbonisation scenarios. The outcomes are expressed as the difference from the value in 2050 projected under a 'current policies' scenario consistent with the European Commission's REF2016 projection[15].

Table 1: EU28 macroeconomic outcomes in 2050 under decarbonisation scenarios, differences from REF2016 projection

	HighE Passive	HighE Breakthrough	HighE	HighM	HighM E-Gas	HighM Imports
GDP (%)	2.0	2.1	2.1	2.2	2.6	0.7
EMPLOYMENT ('000)	1,214	1,852	1,754	1,215	892	1,355
INVESTMENT (%)	5.5	3.5	3.6	6.6	9.8	1.6
REAL HOUSEHOLD DISPOSABLE INCOME (%)	0.4	1.5	1.4	0.4	-0.3	0.8
BALANCE OF TRADE AS % OF GDP (PP)	0.4	0.3	0.3	0.3	0.3	-0.2

Source: Cambridge Econometrics and Element Energy.

The first four scenarios, which depend upon a combination of renewable electricity and green hydrogen produced in Europe, have broadly similar GDP impacts (an increase of about 2% in the level of GDP in 2050 compared with REF2016). The impact on GDP is modestly positive even though energy system costs are higher because the energy expenditure on fossil fuel imports in the reference case is spent, in the decarbonisation scenarios, on equipment with a greater European content, which stimulates production, jobs and incomes in Europe.[16] The additional GDP impact is led by investment spending, which the table shows is some 3-7% higher than the reference case. Energy system costs and energy prices are higher in the 'HighE-Passive' and 'HighM' scenarios and this is reflected in the much smaller boost to real household disposable income (0.4% instead of about 1.5%). These two higher-cost scenarios also give a smaller boost to jobs (1.2m instead of 1.75-1.85m) because the employment impact of investment-led spending is lower than that of household-led spending.

The 'HighM-Imports' scenario has the smallest GDP impact relative to the reference case (0.7%). The additional investment required is the smallest of all the scenarios (an additional 1.6% in 2050) because no investment is required in Europe to produce the hydrogen. However, Europe's balance of trade is worse than in the reference case (by -0.2 percentage points of GDP) and the difference compared with the other scenarios is even greater, even though those scenarios involve higher investment and household spending which ultimately stimulate additional imports as well as European production.

In macroeconomic terms, the 'HighM-E-Gas' scenario has an impact that is similar in kind but more pronounced compared to 'HighE-Passive' and 'HighM'. It involves a marked diversion of spending from households (whose real income is cut by 0.3% compared with the reference case) to investment (9.8% higher in 2050 than the reference case). The investment demand gives the strongest boost to GDP of all the scenarios, but at a high cost to household energy prices, welfare and spending on non-energy products, and this is reflected in the smallest jobs impact of all the scenarios.

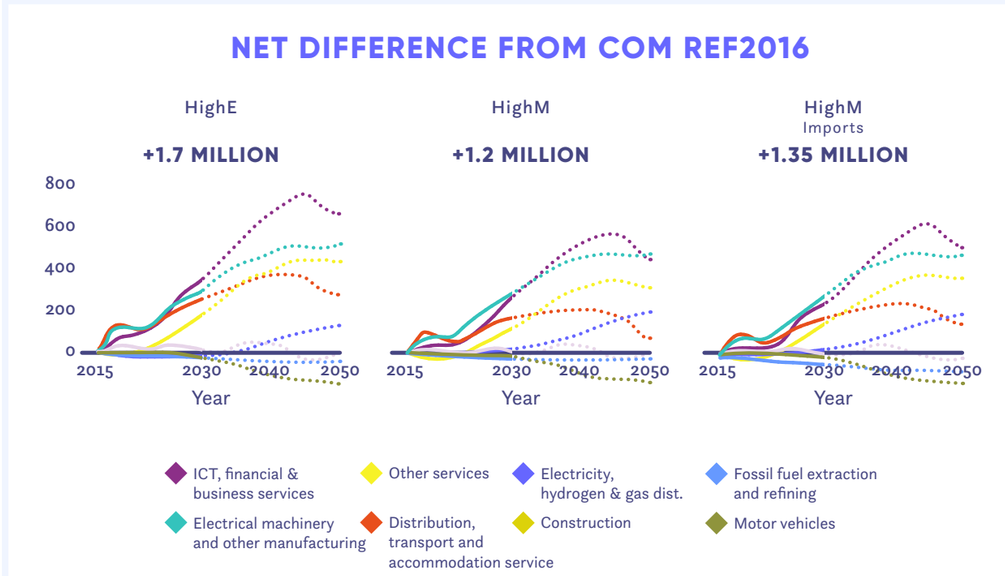
JOBS BY SECTOR: UP TO 1.8 MILLION ADDITIONAL JOBS WITH BREAKTHROUGHS IN BUILDING EFFICIENCY AND SMART ELECTRIFICATION

The scale of structural change is illustrated by the impact on jobs in different sectors. Figure 16 shows the difference compared with the REF2016 projection in the number of jobs in major groups of sectors under three of the scenarios.

In total, some 1.8 million additional jobs could be created if either of the routes of smart electrification ('HighE') or energy efficiency and vehicle-to-grid technology ('HighE-Breakthrough') are realised, and about half a million more jobs than in the 'HighM' scenario.

The pattern of impacts is similar in each case. Jobs are lost in fossil fuel extraction and refining as use of these fuels is phased out. Jobs are lost in the motor vehicles industry but gained in electrical machinery and other manufacturing, reflecting changes in the value added captured in different parts of the motor vehicles supply chain for zero emission vehicles. Jobs are gained in the production and distribution of electricity and hydrogen (but lost in the distribution of natural gas), and jobs are also gained in the production of equipment for electricity generation, distribution and storage (included in electrical machinery and other manufacturing). The biggest job gains are in service sectors that benefit indirectly from higher investment and consumer spending: business services (including finance); distribution, transport & accommodation; and other services. The time profile for the jobs impacts reflects the assumptions for the stepping up of investment in the period up to the mid-2040s in order to achieve decarbonisation by 2050.

The scale of the impact of jobs differs between the scenarios. The scenarios that achieve decarbonisation with the least increase in energy system costs have a larger positive impact on household income and spending, which particularly boosts service sector jobs. In Figure 16 this is illustrated by the 'HighE' scenario. The scenarios that produce a greater diversion of spending from households to investment by raising energy costs create fewer jobs, illustrated in the figure by the 'HighM' scenario. The 'HighM-Imports' scenario ranks low in terms of the increase in energy system costs but it has a higher leakage of energy spending from the European economy and so it also results in a smaller boost to European jobs.



Dash lines reflect uncertainty in employment sectors after 2030

Source: Cambridge Econometrics and Element Energy

FIGURE 16: *Impact of the scenarios on household spending on energy, 2050*

3.4 ISSUES RAISED BY THE MACROECONOMIC ANALYSIS

JUST TRANSITION

While the analysis confirms that decarbonisation can be achieved with modestly positive macroeconomic impacts, all the scenarios involve substantial structural change in the economy. Output and jobs will be lost among firms and places that specialise in producing and processing fossil fuels, and gained by those who specialise in producing low-carbon technologies. Energy-intensive manufacturing sectors will meanwhile face higher costs. We assume that their competitors elsewhere in the world are facing similar increases, which mitigates the impact on competitiveness, but customers for these products may find ways to economise on their use in response to the signal given by higher product prices.

Structural change in jobs and the geographical concentration of job losses will need a policy response to support incomes and the transition of workers into new jobs.

DISTRIBUTIONAL IMPACTS ON HOUSEHOLDS

There are two kinds of distributional impacts on households. Firstly, some households will face job losses as a result of the structural changes described above, and the geographical concentration of vulnerable sectors present the risk that alternative jobs may be hard to find. This highlights the importance of policy measures to support incomes and retraining.

Secondly, households face higher energy costs in all the scenarios, and energy bills account for a relatively high proportion of the spending of poor households. While higher energy prices can be mitigated to some extent by actions to curb energy use, notably in the 'HighE-Breakthrough' scenario which includes substantial improvements in energy efficiency, poor households typically have neither the financial capacity nor the right (because they do not own their homes) to take those actions. This highlights the importance of policy measures to improve the energy efficiency of poor households' homes and to facilitate the take-up of low-carbon heating appliances.

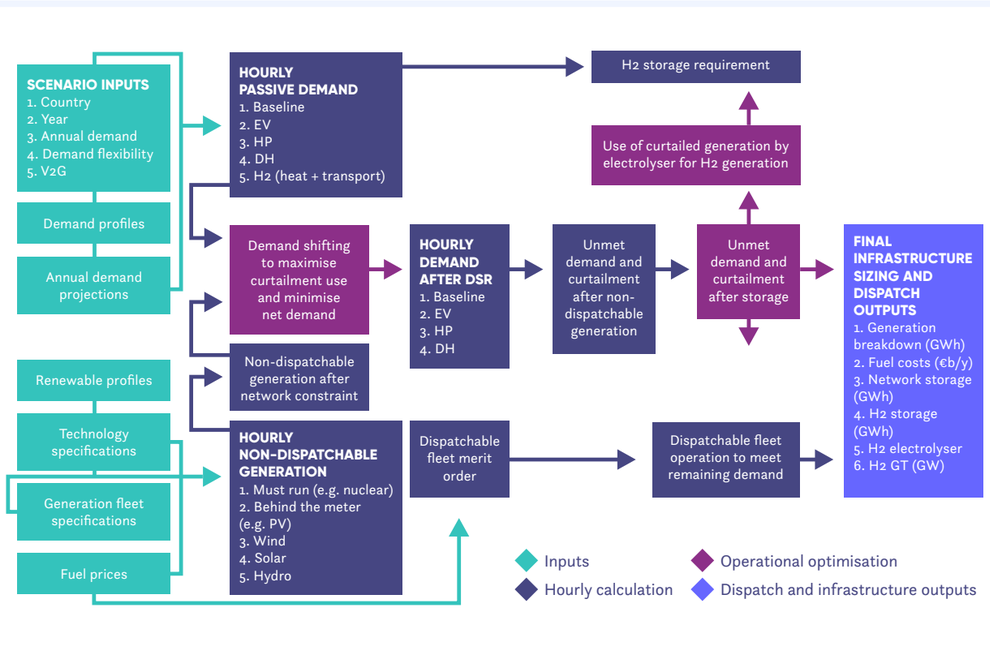
FINANCING

In many cases the transition involves substituting more up-front capital spending for reduced ongoing fuel costs. Access to finance capital to support this is therefore critical, both on a small scale (for example small haulier firms wanting to invest in zero emission trucks, households seeking to purchase zero emission cars and heat pumps) and a large scale (the investment by power companies in renewable technologies, distribution and storage, and investment by energy-intensive companies in zero emission technologies and energy efficiency).

Image: BlackRockSolar (CC BY 2.0)

APPENDIX:

MODELLING METHODOLOGY



ANNEX FIGURE 1

4.1 ENERGY SYSTEM MODELLING

4.1.1 DEMAND PROFILE AND FLEXIBILITY

The model can be populated with a detailed breakdown of the demand by end use types. The demand is differentiated based on its hourly profile and potential for flexibility. Currently the model has following demand segmentation (although the data architecture allows for adding further demand categories):

- Baseline (residential +commercial + industrial consumption)
- EV home charging
- EV workplace charging
- EV public charging
- EV HGV
- Residential HP
- District heating HP
- Electric heating
- H2 heating
- H2 transport

The annual demand and profile for each of these demand types is defined to calculate the passive hourly profiles. In addition, the share of demand that is flexible and the period of flexibility is also specified. The flexible demand is derived by shifting demand to hours or low net demand i.e. demand net of renewable and must-run generation. This includes the following four flexibility options:

HEAT PUMP FLEXIBILITY

The residential HP demand flexibility is based on the thermal storage availability (e.g. hot water storage, advanced phase change material storage etc). This allows the HP to operate during times of low net demand to fill the thermal storage and during times of high net demand. The flexibility is based on a daily operational cycle i.e. the storage flows (charge and discharge) over a day are balanced.

EV FLEXIBILITY

The residential EV demand flexibility is based on the EV connection profile, duration of connection and the typical daily EV demand. The smart EV profile also depends upon the duration of charging period e.g. EV could be charged every day during hours of lowest net demand every day. However, since on average the daily EV demand is small compared to the available battery storage, the period of charging could be extended over a few days to maximise the benefit of smart charging, thus allowing smart EV charging to utilise otherwise curtailed generation.

DAILY FLEXIBILITY

The daily flexibility captures the flexibility of demand types that can be shifted to any hour of the day e.g. residential DSR of smart wet appliances, EV HGV, district heating HP (due to availability of thermal storage).

ANNUAL FLEXIBILITY

The annual flexibility represents the demand for hydrogen generation via electrolysers. This demand can be shifted on a seasonal basis to produce hydrogen during periods of sustained curtailment and storing in large seasonal stores e.g. underground salt caverns. Excess hydrogen production may also be needed to balance the system via use of hydrogen gas turbines during times of peak demand and low renewable generation.

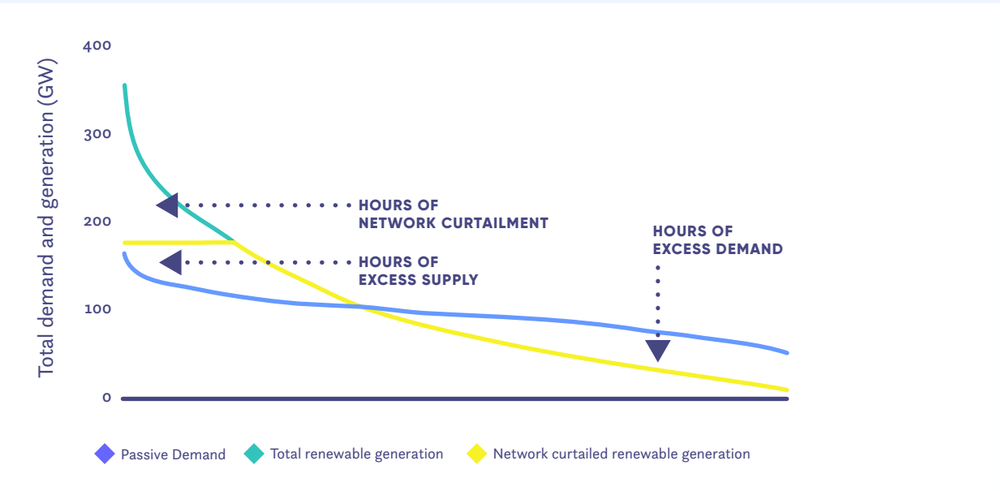
4.1.2 RENEWABLE GENERATION AND NETWORK CONSTRAINTS

The model calculates the total renewable generation requirement in the system based on the defined capacities of the renewable technologies (wind, solar, hydro) and the weather data. This is defined for each spatial region in Europe (the user can define multiple spatial regions and their weather conditions). Furthermore, the model also has constraints of the local utilisation of renewable generation as well as the transmission capacities linking any two regions for maximum import or export. These connections can be defined as hard constraints, i.e. any excess generation is assumed to be curtailed, or the user may specify maximum utilisation of renewable generation to then identify the required transmission network infrastructure and additional upgrades relative to existing network capacities.

The model also has the option to calculate the cost optimal distribution network capacity based on the total network generation required from renewable (to meet a specific CO_2 content target), the levelized capex of renewable and the levelized capex of distribution network. For highly constrained systems, i.e. where a large share of renewable generation is required and thus the total installed renewable capacity is much larger than network capacity, the incremental reduction in renewable capacity is much larger than the corresponding increase in network capacity. However, if there is sufficient demand for upstream of network hydrogen production via electrolyser, then investment in hydrogen pipeline infrastructure could be more cost effective.

4.1.3 TOTAL NON-DISPATCHABLE GENERATION AND NET DEMAND PROFILE

The model calculates the total generation from renewable and must run capacity to identify the remaining net demand for each hour. This can be positive indicating the need for additional dispatchable generation, or negative highlighting the hours of curtailment. The flexibility of demand is then utilised to maximise the use of curtailed generation and minimise the need for dispatchable generation. Thus the flexibility helps to not only reduce the annual generation (TWh) from dispatchable plants but also reduces the overall capacity (GW) of the generation fleet.



ANNEX FIGURE 2

4.1.4 STORAGE AND V2G OPERATION

The model has a storage module to represent additional flexibility available via grid batteries. The model looks at the potential storage flows of various battery size (e.g. from 1GWh to the maximum seasonal storage requirement) to calculate the annual throughput and thus the equivalent cycles. A cost optimal storage size is then selected, based on a minimum cycling threshold, and operated in an optimal manner to reduce curtailment and maximise the peak net demand reduction. In scenarios with vehicle to grid (V2G) the collective stock battery storage is calculated and operated in a similar manner to grid storage, within the constraints of:

1) Battery capacity available for discharge

2) Share of stock participating in V2G

3) Share of stock connected to grid

4) Connection charging rate

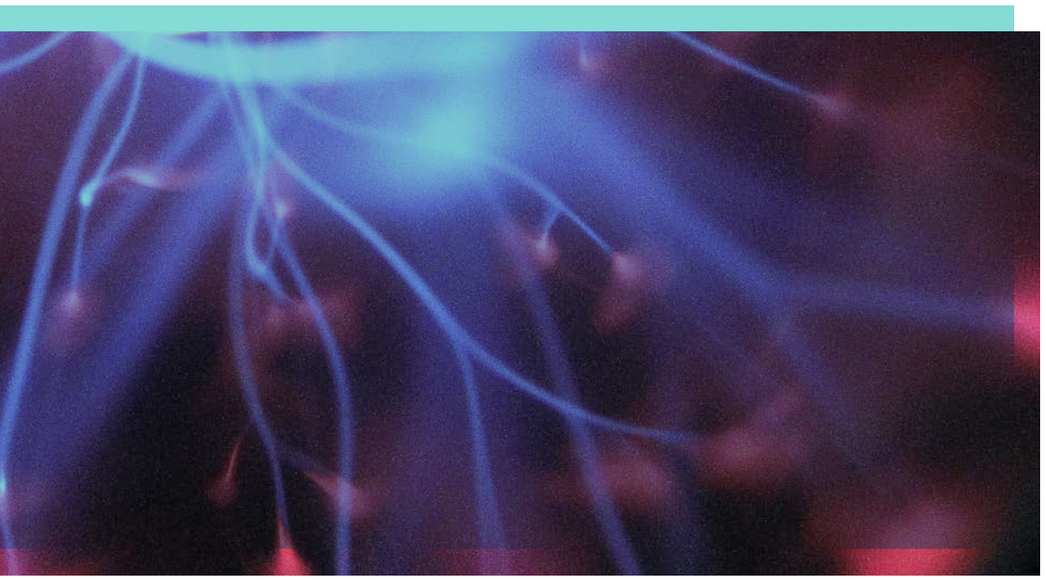
Image: SBA73 "Forn Solar" (CC BY-SA 2.0)

4.2 ANNUAL HYDROGEN PRODUCTION AND STORAGE

The model finally considers the annual demand for hydrogen generation via electrolysers, using the remaining curtailed generation. This could be curtailment due to network constraints or lack of coincident demand. The resulting load factors of electrolyser operation are calculated, if these are lower than a user defined threshold for economic operation (based on a target hydrogen price), then the model calculates the increase in renewable capacity required to meet the desired load factors. This operational profile of an electrolyser, as well as the demand profile of hydrogen use for heating and transport, is used to calculate the seasonal hydrogen storage requirement.

4.3 DISPATCHABLE GENERATION OPERATION

The model calculates the short run marginal cost of generation of all dispatchable technologies to generate a merit order for dispatchable fleet. This curve is based on the fuel costs, range of efficiencies across fleet of technology types and typical technology plant sizes. This dispatch curve is then used to identify the plants and generation technologies utilised in each hour to meet the remaining unmet demand i.e. when the net demand after demand flexibility and storage is still positive. If the dispatchable generation capacity is not sufficient, hydrogen gas turbine may be utilised. This results in additional demand for hydrogen generation which is added to the existing hydrogen demand for heating and transport to identify if the electrolyser load factor threshold is met and if there is sufficient curtailed renewable generation. The model then calculates final adjustment to renewable capacities, if required, to produce excess generation.



4.4 ANALYSIS METHOD: MACROECONOMICS

4.4.1 E3ME

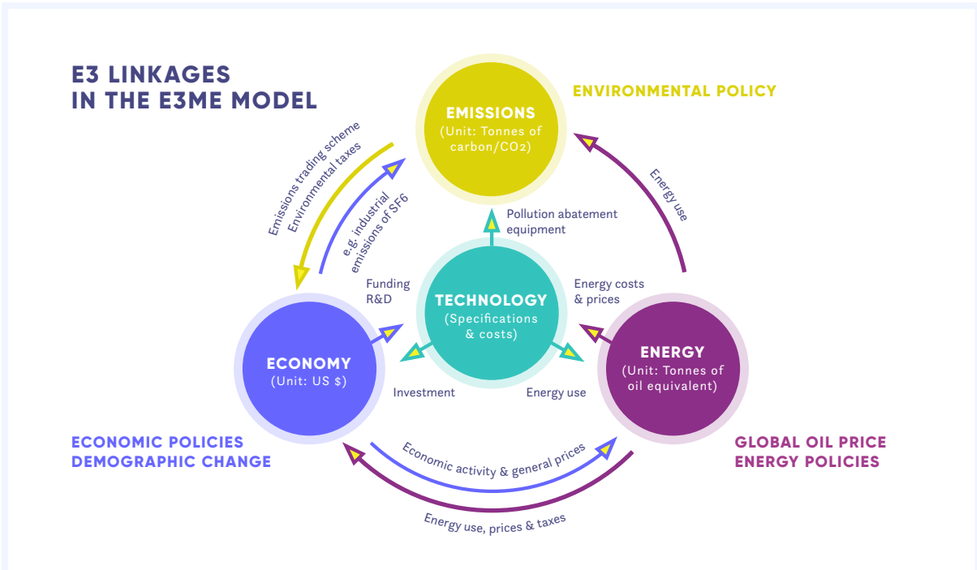
The macroeconomic analysis was carried out using the E3ME global macro-sectoral model, which has been designed to model the economic impacts of long-term energy-economy-environment scenarios.

E3ME's features include:

- complete representation of the economy, energy systems and key aspects of the environment, and the inter-linkages between each of these components
- a high level of granularity, including coverage of 59 nation states/regions and up to 70 distinct economic sectors
- explicit representation of the drivers of technology take up and the interactions between energy policy and technology
- an econometric approach, which provides a strong empirical basis and does not impose the assumption of optimising behaviour by agents

E3ME models the linkages between the energy system, the environment and the economy. Changes in the energy system feed into the economy via changes in energy prices, energy use, the energy generation mix and the demand for carbon-based or clean technologies. Industries and consumers respond to changing prices, which leads to changes in output and incomes across different regions and sectors. The E3-linkages support the modelling of scenarios that capture the potential economic impacts and transition risks associated with a range of policies, to a high degree of regional and sectoral detail.

Figure 4 summarises the key energy, economy, and environment linkages and the important role of technology in each of these domains.



ANNEX FIGURE 3: *E3 linkages in the E3ME model*

E3ME has been developed and applied since the early 1990s. Recent applications include:

- The macroeconomics of the Energy Union, European Commission (DG Energy), 2018-2021
- Modelling the economic impacts of A Clean Planet for All, A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy ('the Long-Term Strategy'), European Commission (DG CLIMA and DG Energy)
- Study on the impacts of EU actions supporting the development of renewable energy technologies, European Commission (DG Research), 2017-2018
- Study on energy prices, costs and subsidies and their impact on industry and households, European Commission (DG Energy), 2017-2018
- Renewable Energy Benefits, International Renewable Energy Association (IRENA), 2016-2017
- The macroeconomic impacts of energy and climate policies, European Commission (DG Energy), 2015-2017

4.4.2 REPRESENTING THE SCENARIOS IN E3ME

Inputs were taken from bottom-up models developed by Element Energy, including those described in Section 5.1 that represent

- the capacity and generation of electricity by different technologies in 2050 and the associated investment requirements
- the capacity and use of fuels for household heating by different technologies in 2050 and the associated investment requirements (including investments in energy efficiency)
- the adoption and diffusion throughout the stock of road transport vehicles of different powertrains

These outcomes for the energy and road transport system are imposed in E3ME, which also represents developments among other energy uses in the economy but without the specification of bottom-up technological detail. The focus in this study has been on the differences for the energy uses that have been modelled in bottom-up detail.

ENDNOTES

1 For example, flexible technologies are automatically dispatched to minimise net demand battery deployment is sized per scenario to an economically optimized level. Similarly, electrolyser, H2 storage and peaking plant capacities are optimized within each scenario. Also, the balance between demand-related and network-related VRES curtailment is explored and used to determine optimum levels of network investment in each scenario.

2 See also 'Economics of converting renewable power to hydrogen' (Gunther Glenk & Stefan Reichelstein, Nature Energy, 2019)

3 Methane is a much more potent greenhouse gas than CO2, with one tonne of methane equivalent to between 84–87 tonnes of CO2 over a 20-year period (or 28-36 tonnes of CO2 in a 100-year period). The IEA estimates global methane leakage rates associated with natural gas supply chains are at around 1.7% on average. (IEA, World Energy outlook 2017)

4 "What is the role for renewable methane in European decarbonization", International Council on Clean Transportation, 2018.

5 See www.e3me.com for more details.

6 The reference case that was chosen for comparison is the European Commission's EU Reference Scenario 2016, available at https://ec.europa.eu/energy/sites/ener/files/documents/20160713%20draft_publication_REF2016_v13.pdf.

7 Higher annual load factors make PV more cost effective, while consistent load factors across the year also means a lower normalised peak i.e. GW/GWh.

8 Flexibility from sources such as V2G means grid-battery utilization is too low to achieve the operational cycling required for economic deployment.

9 Note that HighE includes some fuel cell cars, which require hydrogen. The size of the store in this scenario would be reduced if it only were required to produce fuel for H2GT peakers.

10 SBC Energy Institute 2014

11 'Annualised costs' are here defined as the annual operating costs plus the capital costs divided by the lifetime of the asset.

12 Purchases of hydrogen are shown separately in the 'hydrogen imports' scenario because the hydrogen is not produced in Europe. In the other scenarios the cost of hydrogen is incorporated in the energy supply costs (because it is produced using electricity from renewable sources).

13 The costs include expenditure on energy fuels used in the home and on energy heating systems (for example, heat pumps and H2 boilers). The costs do not include spending on cars and road fuels: these are lower in the scenarios than in REF2016, because the total cost of ownership of zero emissions vehicles is expected to be lower than for petrol and diesel vehicles.

14 The cost of the energy efficiency measures is not included in the energy spending shown in the figure. The cost of these varies according to the extent of efficiency improvement and the nature of the housing stock, but the scale assumed in this study would still leave the HighE-breakthrough case ranking the lowest among the scenarios.

15 REF2016 incorporates some progress towards decarbonisation reflecting the policies that had been agreed at the time when it was produced in 2016. Since then further commitments have been made and these, together with updated assumptions for technology costs, will be incorporated in the next reference projection when it is published. The more ambitious the reference projection is in terms of decarbonisation, the smaller would be the differences brought about under full decarbonisation of the kind represented by the six scenarios presented here (because a greater share of the changes envisaged under full decarbonisation would already be included in the reference projection). However, the differences between the six scenarios and their relative ranking in terms of economic impact would be unaltered.

16 Under the assumption that European capacity and production can be increased on this scale without significant inflationary pressure.

17 See www.e3me.com for more details.

https://europeanclimate.org/net-zero-2050/
2050@europeanclimate.org

NET ZERO 2050