ROADMAP 2050

A PRACTICAL GUIDE TO A PROSPEROUS, LOW-CARBON EUROPE

TECHNICAL ANALYSIS

GREEN EUROPE
80% CO2 REDUCTION
SUSTAINABLE ENERGY
LONG TERM GDP GROWTH
SUSTAINABLE ENERGY
ECONOMIC GROWTH
LESS POLLUTION
INTERGRATED EU
JOB CREATION
DEMANDSIDE MANAGEMENT
CO2 REDUCTION

PREFACE

In July 2009, the leaders of the European Union and the G8 announced an objective to reduce greenhouse gas emissions by at least 80% below 1990 levels by 2050. In October 2009 the European Council set the appropriate abatement objective for Europe and other developed economies at 80-95% below 1990 levels by 2050. In support of this objective, the European Climate Foundation (ECF) initiated a study to establish a fact base behind this goal and derive the implications for European industry, particularly in the electricity sector. The result is *Roadmap 2050: a practical guide to a prosperous, low-carbon Europe*, a discussion of the feasibility and challenges of realizing an 80% GHG reduction objective for Europe, including urgent policy imperatives over the coming five years. The scientific basis and the political process behind the setting of that objective are not discussed.

This is the first of three volumes. It is a technical and economic assessment of a set of decarbonization pathways. Volume 2 will address the policy and regulatory implications arising from the analysis, and Volume 3 will address the broader implications for society. ECF strongly recommends that further work be carried out that will help stakeholders understand the required change in more detail, including the different ways in which various regions would experience the transformation.

Roadmap 2050 breaks new ground by outlining plausible ways to achieve an 80% reduction target from a broad European perspective, based on the best available facts elicited from industry players and academia, and developed by a team of recognized experts rigorously applying established industry standards.

This study is funded by ECF, which itself is funded solely by private philanthropic organizations[1]. ECF does not have financial ties to EU political bodies, nor to business. Representatives of the European Commission and its services have provided strong encouragement for the development of this undertaking and have given welcome guidance regarding the objectives and the approach. Along with representatives of other EU institutions, notably the European Parliament and Council of Ministers, the European Commission has been consulted periodically throughout the course of the project. In addition, a wide range of companies, consultancy firms, research centers and NGOs have counseled ECF in the preparation of this report. These organizations can be found in the acknowledgements section.

1. ECF's funding sources are fully disclosed on its website, www.europeanclimate.org

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The work on the three volumes of the Roadmap 2050 project has been undertaken by:

- Volume 1 - Technical and Economic Analysis: McKinsey & Company; KEMA; The Energy Futures Lab at Imperial College London; Oxford Economics and the ECF
- Volume 2 - Policy Report: E3G; The Energy Research Centre of the Netherlands and the ECF
- Volume 3 - Graphic Narrative: The Office for Metropolitan Architecture and the ECF

In addition, a wide range of companies, consultancy firms, research centres and NGOs have provided various forms of assistance during the preparation of this report. These organisations have provided valuable counsel that we have tried faithfully to reflect in this analysis, however their willingness to consult and to be consulted in the course of this work should not be taken to mean that each of them agrees with all of its assumptions or conclusions.

The ECF is the sole author of the Roadmap 2050 report, is solely responsible for its content and will act as a guardian of the content. The materials can be freely used to advance discussion on decarbonisation of the power sector and the broader economy. The report is made available to any and all audiences via a Creative Commons license. For details of the terms and conditions, please see www.roadmap2050.eu/cc

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For more information on Roadmap 2050:
www.roadmap2050.eu
European Climate Foundation:
www.europeanclimate.org

DEFINITION OF THE "ROADMAP 2050" STUDY

Roadmap 2050: a practical guide to a prosperous, low-carbon Europe has two primary objectives: a) to investigate the technical and economic feasibility of achieving at least an 80% reduction in greenhouse gas (GHG) emissions below 1990 levels by 2050, while maintaining or improving today's levels of electricity supply reliability, energy security, economic growth and prosperity; and b) to derive the implications for the European energy system over the next 5 to 10 years. *Roadmap 2050* addresses at a high level GHG emissions across all sectors of the economy, and it analyses the power sector in depth. The approach taken stipulates the minimum desired 2050 outcome as expressed by European leaders, and then derives plausible pathways from today to achieve them. The methodology is known as "back-casting," to differentiate it fundamentally from forecasting: the end-state is stipulated, that is, rather than derived. A back-casting approach can help to highlight where momentum must be broken and re-directed in order to achieve future objectives, while forecasting tends to extend current trends out into the future to see where they might arrive.

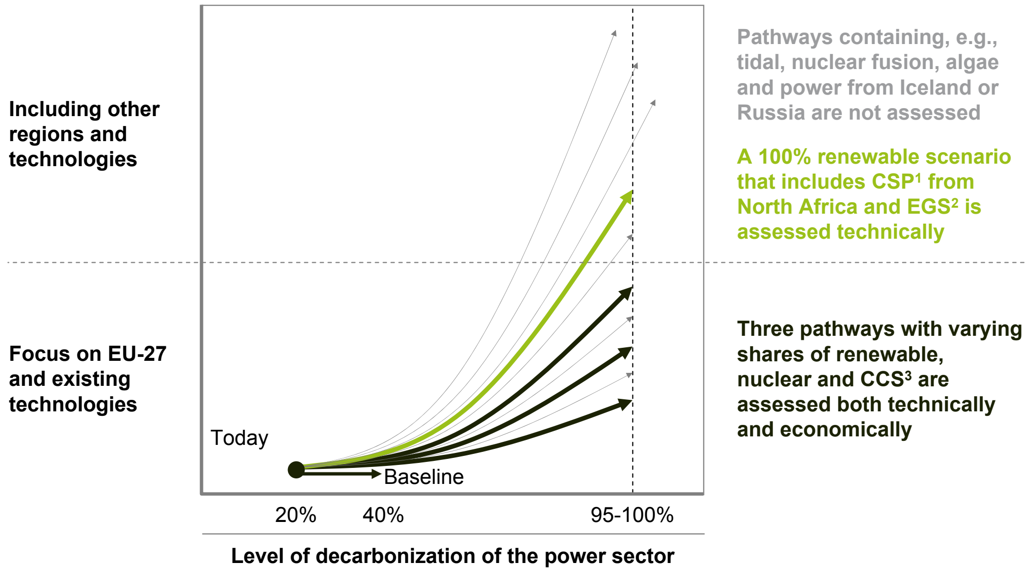
The end-state stipulated for *Roadmap 2050* is an 80% reduction in GHG below 1990 levels by 2050 across the European economy (without relying on international carbon offsets[2]), *and* an energy system that delivers at least the same level of service reliability as Europeans enjoy today. The initial analysis confirmed that it is virtually impossible to achieve an 80% GHG reduction across the economy without a 95 to 100% decarbonized power sector. Three different decarbonized power sector pathways have been studied that differ in the shares of a range of low/zero carbon supply technologies: fossil fuel plus CCS, nuclear energy, and a mix of renewable technologies. In addition, a scenario with 100% electricity from renewable sources was assessed, primarily on the dimension of maintaining the acceptable level of service reliability.

The pathways are designed to be robust; they do not depend on future technology breakthroughs or on electricity imported from neighboring regions. They are based on technologies that are commercially available[3] or in late-stage development today; breakthroughs in technology will only improve the cost or feasibility of the pathways. By design a mix of technologies is used to avoid over-reliance on a few "silver bullet" technologies. This allows resource diversification as well as geographical differentiation. Consequently, the pathways are not fully optimized for lowest cost: they are not based purely on those technologies that are currently expected to be the cheapest in 2050. This approach adds to the robustness of the conclusions; if one technology fails to deliver as expected, the system still works. The technological mix also allows for the development of technologies in those locations where the required natural resource is most abundant. Constraints imposed by land use and by supply chains are taken into account. Finally, a greater diversity of resources delivers greater security of supply, which is an outcome policymakers are likely to seek in any case. A consequence of this approach is that, especially for the first decade, the back-casted technology mixes might differ from analyst forecasts.

Roadmap 2050 provides a robust analysis at a European level of the complex impacts of each decarbonization pathway on the provision of grid reliability services, ensuring that historical levels of supply reliability are maintained. Given limited time and resources, reasonable simplifying assumptions were made and tested regarding regional and local impacts; more detailed follow-on work would be required to address any actual facility planning and siting questions. The transmission grid expansion is

2. While recognizing that well-designed offsets markets can play a role in engaging developing countries and encouraging sound investment in low-cost strategies for controlling emissions in the near to medium term, the availability of CDM credits (or equivalent) to developed economies by mid-century is highly uncertain and likely to be very limited, and therefore this analysis does not rely on significant availability of offsets by 2050.
3. Although the technologies are commercially available today, it is still assumed that the costs will go down over time in real terms. The level of improvement differs by technology

EXHIBIT 0



1 Concentrated Solar Power (thermal, not photo voltaic)
2 Enhanced Geothermal Systems
3 Carbon Capture and Storage

optimized to lowest cost to support the exchange and sharing of renewable resources across the region, and to ensure that low-carbon resources are utilized when available. In doing this, the study makes trade-offs between adding transmission capacity, back-up generation and incurring additional operating costs to balance the power system. The study also evaluates the role of "smart" grid measures in reducing the need for transmission and backup services, by allowing load to participate in balancing the system.

The report addresses the implications of electrification in buildings and transport on final power demand, but it does not attempt a detailed analysis of the decarbonization pathways for either sector. As such the assumption regarding the extent of electrification in transport (vs. biofuels, e.g.,) or regarding the extent of electrification of buildings (vs. biogas heating or zero-carbon district heating, e.g.,) should not be taken as expressing a view that these are the preferred solutions. These assumptions can rather be viewed as presenting a conservative case for the amount of electric demand that must be decarbonized. Should other (non-electric) decarbonization solutions emerge for some portion of either sector, these will only make the power challenge that much more manageable.

Roadmap 2050 is the first of its kind to provide a system-wide European assessment, including a system reliability assessment. It is also the first study to develop its analysis in cooperation with the NGOs, major utility companies, TSOs, and equipment manufacturers across technologies and throughout Europe. The project built on several previous studies, including country specific analyses and technology assessments. It presents new facts, but also leaves room for further fact finding. The report provides insights from fact-based analysis on the technical feasibility of an 80% emission reduction by 2050, on the potential and cost of low-carbon power generation and transmission, and on the impact on the different sectors in the economy. It does not address the costs of distribution network reinforcements incremental to the distribution investments already required in the baseline; however a preliminary effort has been made to gauge the likely magnitude of these investment needs. Beyond imposing reasonable technical constraints, *Roadmap 2050* does not attempt to make judgments on the relative political or social feasibility of implementing various components of the pathways (e.g., for the transmission expansion or extent of new nuclear construction). Neither does the report analyze in detail the potential cost of transition risks. These could be significant if bad policies damage the economy, or investments fail in terms of budget or technology delivery. Finally, *Roadmap 2050* will need to be supplemented by further work to clarify the implications for countries or regions, while preserving an integrated EU perspective.

Evaluation criteria taken into account include a combination of power system reliability, total energy costs, economic and employment growth, security of supply, sustainability and GHG emission levels.

SUMMARY OF FINDINGS

By 2050, Europe could achieve an economy-wide reduction of GHG emissions of at least 80% compared to 1990 levels. Realizing this radical transformation requires fundamental changes to the energy system. This level of reduction is only possible with a nearly zero-carbon power supply[4]. Such a power supply could be realized by further developing and deploying technologies that today are already commercially available or in late stage development, and by expanding the trans-European transmission grid. Assuming (i) industry consensus learning rates for those technologies; (ii) increased emission reduction efforts in the rest of the world; (iii) market demand for low-carbon investments; (iv) IEA projections for fossil fuel prices; (v) a significant expansion of grid interconnection between and across regions in Europe; and (vi) an *average* carbon price of at least € 20-30 per tCO_2e over 40 years, the cost of electricity and overall economic growth in the decarbonized pathways would be comparable to the baseline over the period 2010-2050[5]. In the shorter term, the cost of electricity in the decarbonized pathways is higher than the baseline, more so in the pathways with higher shares of renewable supply. Over the medium and longer term these differences disappear. Because the average costs of the decarbonized pathways over 40 years differ from the baseline cost by less than 15%, other factors, like risk tolerance, technology development, legacy infrastructure, resource availability and security of supply become more important in planning for and implementing a decarbonized power system.

Achieving the 80% reduction means nothing less than a transition to a new energy system both in the way energy is used and in the way it is produced. It requires a transformation across all energy related emitting sectors, moving capital into new sectors such as low-carbon energy generation, smart grids, electric vehicles and heat pumps. These investments will result in lower operating costs compared to the baseline. Dramatic changes are required to implement this new energy system, including shifts in regulation (e.g., to provide effective investments incentives for capital-intensive generation and transmission capacity), funding mechanisms and public support. Despite the complexities, the transformation of the European power sector would yield economic and sustainability benefits, while dramatically securing and stabilizing Europe's energy supply.

Realistically, the 2050 goals will be hard to realize if the transition is not started in earnest within the next five years. Continued investments in non-abated carbon-emitting plants will affect 2050 emission levels. Continued uncertainty about the business case for sustained investment in low-carbon assets will impede the mobilization of private-sector capital. Waiting until 2015 (or later) to begin to build the large amount of required infrastructure would place a higher burden on the economy and the construction industry. Delay would also increase the challenges in transforming policies, regulation, planning and permitting. At the same time, the project to transform Europe's power sector will need to take into account feasible ramp-up rates across all sectors, particularly in the current financially constrained context. In the decarbonized pathways, the capital spent in the power sector goes up from about € 30 billion in 2010 to about € 65 billion a year in 2025. When delayed by ten years, the required annual capital spent goes up to over € 90 billion per year in 2035. This would require steep scale up of supply chains, potentially leading to short term shortages of building capacity, materials and resources. Furthermore, the cumulative emitted CO_2 between 2010 and 2050 would increase substantially. The project requires closer transnational cooperation in transmission infrastructure, resource planning, energy market regulation, and systems operation. Taking all this into account, it is not difficult to see that technological,

4 .Defined as a power sector that emits 5% or less of baseline GHG emission levels.
5. Levelized cost of electricity (LCoE) was calculated without a projected carbon price; a price of €20-30 per tCO_2e would effectively equalize the baseline LCoE with the LCoE of the decarbonized pathways. A significantly higher CO_2 price may be required to provide incentives for new investments. Volume 2 will address the policy implications

regulatory and collaborative activities have to start now in order to ensure a realistic pathway towards achieving the 80% GHG reduction by 2050.

DEPLOYMENT OF EXISTING TECHNOLOGIES COULD REDUCE GREENHOUSE GAS EMISSIONS IN EUROPE BY 80% BY 2050

By deploying technologies already commercial today or in late development stage, Europe could reduce greenhouse gases emissions by 80% by 2050 compared to 1990 and still provide the same level of reliability as the existing energy system. Assuming no fundamental changes in lifestyle, this transition nonetheless requires that all currently identified emission abatement measures[6] in all sectors will be implemented to their maximum potential. These include energy efficiency measures; decarbonization of the power sector; a fuel shift from oil and gas to power and biomass; afforestation; and many others. Specifically, this means that:

- *Energy efficiency* improvements up to 2% per year are realized. This project assumes that energy efficiency measures like those identified in the McKinsey 2030 Global GHG Abatement Cost Curve for Europe are implemented fully and in all sectors. These include aggressive energy efficiency measures in buildings, industry, transport, power generation, agriculture, etc. It also assumes that the energy efficiency measures identified in the 2030 GHG abatement curve penetrate further as the timeframe continues to 2050.

- Nearly full *decarbonization of the power sector* is achieved by relying to varying degrees on renewables, nuclear and carbon capture and storage (CCS), along with a significant increase in transmission and distribution investments.

- *Fossil fuels are replaced* in the buildings and transport sectors by decarbonized electricity and low CO_2 fuels (e.g., 2nd-generation biofuels).

- All *other identified emission abatement* measures are implemented, such as CCS in industry and afforestation.

Prerequisites assumed in *Roadmap 2050* for a reliable and affordable decarbonized power sector include: to have a geographical distribution of supply technologies and resources that have sufficient potential in the aggregate to meet projected demand; to use a mix of technologies rather than a few; to allow sufficient time for the implementation of the pathways to avoid stranded costs due to early retirements (yet to retire plants at the end of their assumed economic lives); and finally to deploy these resources across a transmission and distribution grid capable of fully meeting demand for electricity in all places at every hour of the year to the current reliability standard of 99.97%[7].

Decarbonized electricity consumption in 2050 is estimated to be about 4,900 TWh per year (including Norway and Switzerland), which is approximately 40% higher than today. In the baseline (consistent up to 2030 with IEA WEO 2009), the overall power demand would also grow by about 40% by 2050. *Roadmap 2050* assumes that this “business as usual” growth in demand is avoided almost completely by applying the aggressive energy efficiency measures described above. However, because of growth in new sources of power demand (for electric vehicles and heat pumps in buildings and industry), the overall quantity of demand for electricity in 2050 is roughly the same as it would have been without decarbonization[8] (though overall energy consumption is lower because of the higher efficiency of electric vehicles and heat pumps compared to what they are replacing).

6. This report leverages the extensive work done by McKinsey on the technical GHG abatement potential up to a maximum cost of €60 per tCO2e (and assumes further abatement potential up to €100 per tCO2e). For more details please refer to its report available on its website (“Pathways to a low carbon economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve”).
7. This reliability means that over the course of a year 99.97% of the total electricity demand is delivered. Any demand that is not met is generally managed through contracted “interruptible loads” rather than through brown-outs or black-outs.
8. This is the net sum of economic growth, energy efficiency measures and electrification of transport and heating; if the energy efficiency targets were not met and electrification were still to be pursued as modeled, electricity demand would increase by 80 % compared to today’s levels.

Power generation technologies (and the associated primary energy resources) capable of producing the required 4,900 TWh per year of decarbonized power exist today, either commercially available or in late stage development. Several mixes of power technologies have proven to be feasible, providing reliable power at all times at an economic price on average over the 2010-2050 period. The technologies include hydro; coal and gas plants with CCS; nuclear plants; wind turbines (onshore and offshore); solar PV and CSP; biomass plants; and geothermal plants. The supply mixes tested cover a share of renewable energy between 40% and 100%, a share of nuclear energy between 0% and 30%, and a share of fossil fuel plus CCS plants between 0% and 30%. For both CCS and nuclear a sensitivity up to 60% was assessed on cost and reliability. A supply of solar power from outside Europe (based on commercial CSP technology) as well as breakthrough in technology with enhanced geothermal was assumed for the 100% renewable energy pathway.

The rationale for using a mix of sources rather than a few technologies in each of the pathways is that a) most technologies do not have sufficient theoretical capacity to supply all demand, b) a mix of technologies is more robust against delivery risks, and c) different technologies can be utilized to a greater extent in those regions where they are most suitable. A diversity of resources also enhances supply security. While the three main pathways employ some quantity of nuclear and coal-with-CCS plants operating in customary fashion, neither nuclear nor coal-with-CCS is necessary to deliver decarbonization while maintaining the current standard of reliability (as described in chapter 7 on Further opportunities, with the 100% RES being fully reliable), nor was the combination of nuclear or coal-with-CCS incompatible with high renewable shares. In each pathway, CCS is required to achieve significant abatements in industry. It should be noted that the resulting technology mix is not always similar to the forward-looking projections of industry associations and analysts, especially in the short term.

Implementation of new policies and regulations, orderly construction of new plants, and a smooth build up of the new technology supply chains requires the full period of about forty years available between now and 2050. Existing (CO_2 emitting) plants are assumed to be able to operate to the end of their economic lives[9], at which point their retirements, along with load growth, will create the market demand required for investments in low carbon technologies to deliver the projected learning potential. However, if the new energy system would be delayed significantly at first and then implemented at an accelerated pace later, the risk of a forced retirement of high-emitting plants increases. This would be the result of new plants being built at the beginning of the period, to compensate the slower implementation of low-emitting technologies, that would be replaced by such technologies later but before the end of their economic life. A significant delay in building out the new system could also create a risk of temporary supply chain shortages, which would increase the cost of transition.

Compared to today, all of the pathways, especially those with higher RES penetrations, require a shift in the approach to planning and operation of transmission systems. Electricity demand is no longer fixed and unchangeable. ‘Smart’ investments that make demand more flexible and responsive to the available supply of energy can significantly reduce system costs and implementation challenges. Expansions of transmission system capacity are a crucial and cost-effective way to take full advantage of the low-carbon resources that are available, when they are available[10]. Inter-regional transmission must develop from a minor trading and reserve-sharing role to one that enables significant energy exchanges between regions across the year, enabling wider sharing of generation resources and minimizing curtailment. Operation of the grid must be based on greater collaboration over wider areas. To achieve this, it is paramount that planning and evaluation of transmission investments and operational decisions consider wider regional benefits than is currently the case.

9. The economic lives assumed here are approximations of the average depreciation lifetimes of the various plant types.
10. A detailed assessment of distribution system investments is outside the scope of this report. Distribution investments in the future are likely to be significant, but the extent to which they will be incremental to the baseline, rather than investments already required in the baseline, is unclear.

A significant challenge is the provision of low load factor dispatchable capacity that can be available, for example in winter when there is less solar production and demand is higher. Roughly 10% to 15% of the total generation capacity would be needed to act in a backup arrangement with low load factors. The preferred technologies for the backup service are yet uncertain, and the attractiveness of the various options needs to be assessed in more depth. Currently, likely options include: extensions of existing flexible plants but limited to very low utilization rates[11]; new gas-fired plants (e.g., open-cycle gas turbine plants without CCS)[12]; biomass/biogas fired plants; and hydrogen-fueled plants, potentially in combination with hydrogen production for fuel cells. The implications for gas or hydrogen networks have not been studied in detail. Storage is optimized to create additional flexibility. The study has not assumed any additional large-scale storage capable of shifting large amounts of energy between seasons but with new technology this may become an economic alternative. Neither has vehicle-to-grid storage been assumed. If proven economic and feasible, this could enhance the balancing capability of the system.

DECARBONIZATION WOULD ENHANCE GROWTH AND SECURITY OVER THE LONG TERM

While the unit cost of *electricity* over the 2010-2050 period could be 10-15% higher than in the baseline (excluding carbon pricing), the overall cost of *energy* in the decarbonized pathways declines by 20-30% over the period relative to the baseline, due primarily to greater energy efficiency and a shift from oil and gas to decarbonized electricity in the transport and buildings sectors. In the pathways, GDP growth is slightly higher as a result this improvement in productivity, though the impact is likely to differ from region to region. Reliance on fossil fuels declines significantly in the decarbonized pathways and the use of indigenous energy sources with low or zero fuel costs expands significantly, which together increase the security and stability of Europe's energy supply.

- **Across the energy system** (electricity, oil, gas and coal, supply and demand sectors), the cost of energy per unit of GDP decreases in 2010-2020 by ~15% in the baseline and ~25% in the decarbonized pathways (mostly due to increased efficiency). After 2020, the cost of energy per unit of GDP continue to decrease more strongly in the decarbonized pathways, resulting in a 20-30% benefit in energy cost per unit of GDP in 2050. This is mostly an effect of more energy efficiency and a shift away from oil and gas to power, as well as lower GHG emissions which reduce the exposure to carbon prices. The benefit of the decarbonized pathways is equivalent to a lower total cost of energy of € 350 billion per year by 2050, or € 1,500 per year per household.

- **Within the power sector,** the levelized cost of electricity of the decarbonized pathways is about 10-15% higher than in the baseline. This difference would be bridged with an *average* CO_2 price of at least € 20-30 per ton[13]. A significantly higher CO_2 price may be required to provide incentives for new investments. Volume 2 will address the policy implications. In the decarbonized pathways, the levelized cost of electricity is relatively higher in the 2010-2020 period and relatively lower in the period 2030-2050. This cost evolution reflects an increase in capital invested, offset by a decrease in the overall running costs. The capital costs for the power sector are about 70% higher than in the baseline, with an additional €25 billion per year of investment on average over the 2010-

11. The costs of converting and maintaining an existing fossil plant for this purpose may in most cases be prohibitive relative to alternatives, such as OCGT.
12. In case of gas-fired backup plants, an increase in generation capacity will require an increase in gas transport and storage capacity (to be able to deliver the gas at peak times); however, parts of the current gas transport and storage system might become available for this use, as the system has been dimensioned for winter peak demand for heating from commercial and residential customers which will no longer be needed if all buildings have electric heating.
13. Input assumptions moderately affect these conclusions: an increase in the real after-tax cost of capital from 7% to 9% increases electricity costs by 15% in the decarbonized pathways and by 10% in the baseline. If RES cost reductions fall behind the learning rate assumptions by 50%, the cost of electricity increases by 15% in the decarbonized pathways, and by 2% in the baseline. A 25% higher fuel price increases the cost in the baseline by 10% compared to 5% in the decarbonized pathways.

2050 period compared to the baseline. A market and regulatory environment that offers investors sufficient incentives is required to trigger the required investments in capital-intensive generation and transmission capacity.

While these numbers represent less than 1% of annual GDP over that period, the change is significant for the energy sector. The power sector will require more capital to finance the investments in low/zero carbon generation, transmission and back up capacity. Longer term, the coal, gas and oil sectors may see investments decline by 50% due to lower demand, which can have large implications for certain countries. Clearly, this number depends on the extent to which the lower demand displaces imported vs. domestically produced fuels and to what extent the decline would have happened anyway in the baseline. Notwithstanding a possible decline, fossil fuels still play a significant role in all pathways. Natural gas in particular plays a large and critical role through the transition.

In the 2010 to 2020 period, the slightly higher electricity costs would reduce the growth rate in GDP by 0.02% compared to the baseline. This means that the same 2020 GDP levels would be reached about one month later in the decarbonized pathways than in the baseline. Such macro-economic modeling should be seen with its usual limitations: it is not meant as a forecast but only as a tool to better understand the potential impact of such measures. The results show that the likely impact on GDP growth is lower than the customary margin of error for macro-economic forecasts. Higher electricity prices may reduce competitiveness for sectors that compete globally and have a high share of energy costs, though can be offset to some extent by investments in energy efficiency. If Europe is able to build and maintain a leading position in clean technology, increased exports could contribute about €25 billion per year to GDP in this first decade, similar to the contribution of about 10 of the largest European technology providers. This is equivalent to a contribution to GDP growth of about 0.04% per year.

From 2020 to 2030, the cost of energy (power and primary energy) per unit of GDP is already lower than in the baseline, as more energy efficiency is realized and oil and gas demand is shifted to electricity, which is lower cost and results in greater energy efficiency. Annual GDP growth could be slightly higher than in baseline, by about 0.03%.

In the 2030 to 2050 period, the cost of energy per unit of GDP output could be about 20 to 30% lower in the decarbonized pathways than in the baseline. The lower cost is due to the large implementation of energy efficiency levers and a significant shift away from oil and gas in transport and buildings, with electric vehicles, fuel cells and heat pumps being both more efficient than current technologies and using lower-cost energy sources. Though the total bill for electricity in the decarbonized pathway is similar to the baseline, on an overall energy system level (power, oil, coal and gas), the annual cost advantage could grow to €350 billion per year in 2050. As a result, the annual GDP growth rate in the decarbonized pathways is about 0.07% higher than in the baseline. Achieving the energy efficiency reductions is of critical importance: if only half of the desired energy efficiency measures were achieved, and the cost doubled, GDP in the decarbonized pathways would be €300 billion lower by 2050, eroding the improvements in productivity and imposing additional investment requirements for generation and transmission.

The changes in the energy system would have an impact on overall employment. New jobs are created to implement energy efficiency measures (e.g., building insulation) and to develop and install new technologies (e.g., heat pumps, electric cars and hydrogen fuel cells, capital investments in power generation and transmission). Sectors that benefit most are construction and mechanical engineering. The total number of these new jobs by 2020 could range from 300,000 to 500,000. At the same time, employment in some primary energy supply chains may erode, depending whether it is European fossil fuel production or imports that are displaced. Demand for oil, coal and gas may decrease by 60 to 75% between 2010 and 2050 compared to the baseline. Over 250,000 jobs could be at stake, both in the baseline and the decarbonized pathways. Clearly, some regions will be hit harder in this respect than others. Short-term interventions could ensure that employees in vulnerable industries and regions are appropriately supported, both in financial assistance and in skills retraining, in the transition years 2010-2020[14].

The security of Europe's primary energy supply is improved in the decarbonized pathways. Substantial benefits can be expected in terms of the resilience of the economy to volatility in fossil fuel prices. A spike in oil and gas prices has often been the spark that ignites a recession. On a total economy level, the demand for coal, oil and gas would be reduced significantly. Fuel sourced from non-OECD countries for power supply could decrease from 35% of total fossil fuels in the baseline down to 7% of total fossil fuels in the pathway that relies on 80% renewable energy sources. Moreover, the absolute volume of fossil fuels is lower in the high renewable energy pathways. At the same time, local control of power supply for each member state in the EU remains similar to what it is today, as significant capacity in backup plants ensures sufficient local production is available to cover most of the local demand for electricity. Sufficient grid and back up investments can ensure that the increased intermittency of the decarbonized pathways delivers reliable power.

IMPLEMENTATION IS THE BIGGEST CHALLENGE

Although the decarbonization pathways seem feasible from a technical and economic viewpoint, the feasibility of implementation is less obvious. The magnitude of change required in the sectors affected is substantial in all of the decarbonization pathways tested. Between now and 2050, a decarbonized economy will have to achieve the following milestones:

- On average, the pathways require the installation of about 5,000 square kilometers of solar panels over 40 years equaling about 0.1% of the area of the European Union (assuming 50% of these being rooftop solar panels). This requires significant project management efforts and (spatial) planning and permitting at large scale. The new installation and replacement of close to 100,000 wind turbines (of which half could be at sea), equaling 2,000 to 4,000 new wind turbines per year. This is about the same pace as the wind sector has built over the past decade, albeit that the new wind turbines are significantly larger (up to 7-10 MW), with a large share offshore in challenging conditions.

- The addition of significant new transmission capacity, with several thousands of kilometers of new inter-regional transmission infrastructure required. The overall expansion required over 40 years is a factor-three increase from today's level of inter-regional transmission capacity. In some corridors the expansion will be even greater, such as, for example, in Iberia to France, where capacity is currently less than 1 GW and the required increase would range from 15 to 40 GW (high end of the range with 80% RES penetration). Clearly this will not be possible unless the historical pattern of public opposition is addressed; among other things, this will involve reconsideration of public planning processes to bring greater clarity of purpose and remove barriers. Alternative solutions to overhead lines over the Pyrenees may need to be considered[15], as well as alternative generation mixes with higher wind and lower solar generation. Additionally, enhanced local distribution networks and IT applications for smart grid functionality must be implemented on top of the baseline maintenance, expansion and upgrades already anticipated.

- Approximately 190 to 270 GW of backup generation capacity is required to maintain the reliability of the electricity system, of which 120 GW already in the baseline. This represents 10 to 15% of total 2050 generation capacity (the high end being the 80% RES pathway). This capacity would be required on a regional basis and will be run at load factors of less than 5% for

14. However, concerns about carbon leakage through the potential relocation of industry due to stringent emission regulations seem to be often overplayed: external research indicates that less than 1% of industrial production could potentially relocate. While many factors influence such decisions, further research is required to clarify what level of carbon penalty could affect the share of industry affected.
15. E.g., underground and sub-marine cables; in costing new transmission needed in the decarbonized pathways, it has been assumed that a mix of AC and DC, overhead, underground and sub-marine technologies will be deployed, which reflects in part the assumption that transmission cost levels between Iberia and France are based on deploying a disproportionately high percentage of underground and/or sub-marine cables.

the 40%/60%/80% pathways and up to 8% in the 100% RES pathway.

- In each of the pathways, CCS is required. The three main pathways include CCS for power generation and all scenarios require CCS to abate industrial emissions, e.g., for steel, refining, chemicals and cement. The realization of an extensive CO2 transportation and storage infrastructure across certain regions in Europe, depending on where and how CCS will be most intensively deployed.

- In the 40% RES pathway, about 1,500 TWh per year of nuclear production is required, compared to approximately 1,000 TWh per year today. Approximately 200 GW of new nuclear plants would need to be built, representing approximately over a hundred new nuclear plants entering construction by 2040. The 80% RES pathway requires that about half of the current level of nuclear production is replaced.

- The deployment of potentially up to 200 million electric and fuel cell vehicles and potentially around 100 million heat pumps for buildings or city districts across Europe. Achieving these goals would require a fundamental transformation of the automotive supply chain as well as a large construction effort in buildings and associated infrastructure.

The fundamental transformation of all energy-related sectors requires steep growth of supply chains for engineering, manufacturing and construction of power generation, transmission infrastructure, energy efficiency measures, new car types, etc. Yet the required rate of growth is not without precedent, and it is considered feasible by industry experts. Funding requirements shift substantially. Within the power sector, about € 30-50 billion per year of additional funds are required for more capital-intensive generation capacity and grid investments. Capital for oil, gas and coal supply in Europe may come down by 30%. Funding is required for new investments in energy efficiency measures, heat pumps and alternative drive trains, which may add up to over € 2-3 trillion over 40 years.
All decarbonization pathways explored in Roadmap 2050 confront profound implementation challenges. Some challenges – like the need for large and rapid additions of transmission capacity between and within regions – are common to all pathways, though they differ in scale from one pathway to the next. Other challenges tend to emerge within some pathways more than others – for instance, one pathway relies heavily on a large, sustained nuclear construction program, while others rely heavily on deployment of "smart" demand-side technologies and practices to manage high levels of intermittent supply. Apart from the implementation challenges, the pathways also face large public acceptance challenges. These affect all scenarios, but differ significantly between them across the various dimensions.

Recognizing the current challenges in achieving new licenses and rights of way for transmission lines, a sensitivity was investigated with substantially less transmission than the capacity reached in the optimized case. The alternative to transmission was modeled as additional storage capacity within the system. The analysis shows that there would be a need to add more than 125 GW of new storage capacity (approximately 3 times the existing EU storage capacity) with an associated 50 TWh of energy storage (equivalent to about 50% of the average storage in Norway) spread across all of the regions. An alternative approach could be to supply the additional power required from generation when transmission constraints limit energy import and to allow the curtailment of output from renewable sources when export potential is limited. This approach requires about 40 GW of additional generation capacity and leads to a curtailment of renewables of nearly 10%, three to five times the level of curtailment in the cost optimized case. In both of the alternative cases the overall costs would be significantly higher than those for the cost-optimized transmission investment case.

Delivery risks exist for most technologies. Nuclear and to some extent CCS carry public acceptance risks. Nuclear faces proliferation concerns and issues with handling and disposal of high-level radioactive waste. The quantity of long-term storage capacity that will be feasible for CCS is still unclear, while a CO_2 transport infrastructure will need to be constructed. Onshore wind also faces local public acceptance issues, while offshore environments make the construction and maintenance of offshore wind installations challenging. For biomass, the development of a reliable logistics infrastructure is challenging, as is avoiding competition with food and water and negative effects on biodiversity. Learning for most of the required technologies, particularly for solar and CCS, will need to be achieved through continued R&D, demonstration and/or deployment investments.

Arguably the toughest challenge of all is to obtain broad, active public support for the transformation, across countries, sectors and political parties. Transnational cooperation is required for regulation, funding, R&D, infrastructure investments and operation. Societal enthusiasm for the changes is also needed to draw talent and energy, much as the high-tech sector did in recent decades, to innovate, plan and execute these massive changes in power supply and consumption. Resilience to overcome inevitable setbacks will be required, including initiatives to change public attitudes regarding the construction of large-scale overhead transmission infrastructure.

In summary, the challenge in implementation is not "the same, but more." Europeans possess the skills, the technology, the capital and the industrial wherewithal to deliver this transformation, but the policies and regulations required to mobilize those vast resources to the extent required do not yet exist. If European leaders are serious about achieving an 80% reduction in GHG emissions by 2050, then a heavy burden falls upon policymakers, in Brussels and in member states, to re-shape the energy landscape through enhanced markets and effective regulation.

PRIORITIES FOR THE NEXT 5 TO 10 YEARS

Five priorities must be set for 2010-2015 in order for Europe to progress towards implementation of an 80% reduction target for greenhouse gas emissions by 2050:

1. *Energy efficiency* – The case for transition relies to a large extent on a marked improvement on financial incentive structures and the current pace of delivery of energy efficiency improvements across the economy. It is well established that vast potential exists for cost-effective energy efficiency measures, less costly than supply measures required to replace them. The costs of the transition rise significantly if implementation of energy efficiency measures falls behind. Innovative programs will be needed to eliminate information barriers, reduce transaction costs and mobilize investment capital.

2. *Low carbon technology* – The case presented here does not rely on technology breakthroughs, but it does rely on steady, in some cases dramatic improvements in existing technologies. Coordination of support for development and deployment of, e.g., CCS, PV, offshore wind, biomass, electric vehicles, fuel cells, integrated heat pump and thermal storage systems, and networked HVDC technologies, including adoption of common standards, will be critical. R&D support for, e.g., enhanced geothermal systems, large-scale electrochemical storage and other new, potential breakthrough technologies will enable the transition faster and at lower cost.

3. *Grids and integrated market operation* – A large increase in regional integration and interconnection of electricity markets is key to the transition in all pathways and is urgently required even for the level of decarbonization already mandated for 2020; it is, paradoxically, also the key to reliable and economic integration of localized energy production, along with investments in smarter control of demand and decentralized supply. Effective transmission and distribution regulation, the development of regionally integrated approaches to planning and operation of grids and markets, and support from stakeholders are required.

4. *Fuel shift in transport and buildings*. The aggressive penetration of electric mobility, hydrogen fuel cells and 2nd generation biofuels for the transport sectors required after 2020 is contingent upon urgent action on progressively tightening emission standards, technology development programs and standards development for charging infrastructure. Likewise for buildings, the required large-scale roll-out of heat pumps and, to a lesser extent biomass/

biogas (potentially via district heating) means that these choices must be built into the design of energy efficiency programs in the next few years; roll-out could begin selectively in the near term in new construction to build up the commercial infrastructure required for wider application later on.

5. *Markets* – A massive and sustained mobilization of investment into commercial low-carbon technologies is needed, the vast majority of which will probably come from the private sector. Investors need greater certainty about future market conditions and the future competitive landscape. Current market design, i.e. energy markets based on marginal cost pricing, must be reviewed in light of the capital-intensity of these new technologies. Low-carbon investors need more clarity about the ultimate fate of high-carbon assets, to have sufficient confidence that their investments will be profitable under a sufficiently wide range of future market conditions.

If these priorities are addressed in the next few years, the public, investors and governments can move forward with a comprehensive infrastructure agenda that is consistent with the 2020 and 2050 objectives. This agenda should link to the specific investment agendas of governments, equipment manufacturers, TSOs and utilities.

THE CASE FOR AN ENERGY TRANSFORMATION

The energy transition towards a decarbonized economy has benefits that reach beyond climate change mitigation. This section describes the case for Europe in a broad sense. The study results are put in perspective by arguments both supportive and critical of the case.

RATIONALE FOR AN ENERGY TRANSFORMATION

The case for an energy transformation has been made several times over the past decades. The late 1970s and 1980s saw different levels of progress on biofuels (Brazil), nuclear, efficiency, renewables and cogeneration in response to energy security and environmental concerns. Interest in energy efficiency in particular was spurred by the oil embargo in 1973 and continued through the early 80s, but interest in efficiency waned once the price of oil returned to low levels in the mid 80s. In the 1990s, technology development in wind, solar and batteries as well as the introduction of electricity market liberalization drove the need for and potential of higher renewable targets. Over the past decade a combination of high growth in demand for energy, slowing growth in oil supply and growing concern about climate change have been driving the case for renewable energy and energy diversification. The current case for an energy transformation can be summarized as follows:

A. **Lower energy costs per unit of output and more stable and predictable energy prices.** While unit electricity costs in the decarbonized pathways could be on average 10-15% higher than in the baseline (excluding carbon pricing), energy costs per unit of economic output come down by 20% to 30% compared to the baseline, due to increased energy efficiency and a shift from oil and gas to decarbonized electricity in the buildings and transport sectors. Because the economy in the decarbonized pathways depends on low/zero fuel-cost sources (mostly renewable energy and nuclear), the marginal production costs are low and energy costs are more stable and predictable.

B. **New economic growth and job creation through innovation.** The transition requires about € 7 trillion[16] of investment over the next forty years in new energy efficiency measures, clean technology and new infrastructure. The new technology investments could create between 300,000 and 500,000 jobs. About 250,000 jobs could be at stake in the fossil fuel industry. Clean tech investments could provide a €25 billion annual export market over the first decade, depending on whether Europe can reach and maintain a leading position. The impact is likely to differ from region to region and for different sectors of the economy.

C. **Increased security of energy supply and more economic stability.** Demand for fossil fuels could fall by over 60%, compared to an increase in fossil fuel demand in the baseline. In a future with higher competition for natural resources, Europe would become less reliant on energy imports. It is conceivable that other dependencies could arise in the event that some technology supply chains become more reliant on specific sources for critical materials.

D. **More sustainable energy and fewer emissions.** Greenhouse gas emissions are reduced by 80% in the decarbonized pathways from 1990 versus only a 10% decrease in the baseline, even though the baseline includes significant energy efficiency measures. Depending on emission levels outside

16. This includes € 4.2 trillion that is also required in the baseline

Europe, some cost for climate change adaptation may be avoided. Other emissions, like NO_x, SO_x, black carbon, other particulates and noise will also decline significantly. In the decarbonized pathways, economic growth is more sustainable, as a shift away from fossil fuels is required in any case at some point in the future due to resource depletion.

INSIGHTS THAT MAY CHANGE 'COMMON WISDOM'

This study has provided some facts around key challenges to the feasibility and affordability of an energy transition:

A CO_2 reduction of at least 80% by 2050 is technically possible. A combination of efficiency, near full decarbonization of the power sector and fuel shift in transport and buildings can realize 80% emission reduction compared to 1990. Near full decarbonization of the power sector can be achieved by various mixes of low carbon supply technologies, like renewable energy, CCS and nuclear.

An expanded European grid can effectively reduce intermittency challenges. Intermittency issues on a national scale are becoming significant (e.g., Danish power prices falling to below zero). Local solutions, like storage capacity investments are typically considered. These can alleviate intermittency issues, but often result in relatively high renewable energy curtailment, e.g., up to 15%. The cost of storage plus the loss of renewable power production could be material. A cost effective solution is to expand the inter-regional transmission grid across Europe. Fluctuations in demand and supply are canceled out to a large extent and back up capacity is available at larger scale. The grid investments required are around 10% of generation investments and reduce curtailment to 1 to 5%, making it an effective and economic solution.

A high renewable supply system is technically feasible. Higher levels of intermittency can be managed through a combination of significantly expanding the European transmission grid, building significant back up capacity plants, applying demand response and potentially using energy sources from outside Europe (e.g., North Africa).

Roughly speaking, for every 7-8 MW of intermittent capacity (wind and solar PV), about one additional MW of back up capacity is required. Back up plants form an important part of the system balancing and are required especially at times in winter when the solar power is low, wind lulls occur and the demand for heat pumps is the highest. The load factor of the back up plants is expected to be below 5% for the 40%/60%/80% RES pathways and up to 8% in the 100% RES scenario.

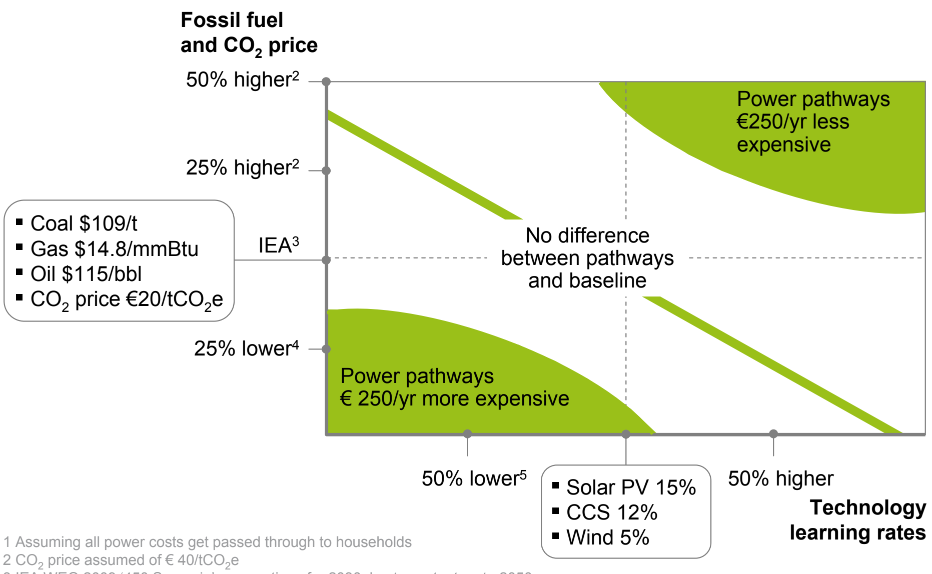
Technology breakthroughs are not required to decarbonize the power sector. All technologies assumed in the three main decarbonized pathways are commercially available at large scale, except CCS, which is in late stage development. Although technology breakthroughs can be expected, they are not required to decarbonize the power sector. Continuous cost reductions are required to make the decarbonized pathways economically competitive versus the baseline. Decarbonization in the transport sector requires mass application of electric vehicles, hydrogen fuel cell vehicles and/or biofuels. This requires a significant improvement in performance and cost. Similarly, decarbonization in buildings requires a breakthrough in the application of heat pumps.

Costs of electricity of the decarbonized pathways are comparable to the baseline and, even with pessimistic assumptions, the impact per household is below € 300 per household per year. Depending on the assumptions, electricity costs can be higher or lower in the decarbonized pathways. If assuming IEA fossil fuel prices and industry average views on technology learning rates, the cost of decarbonized energy is € 100 per year per household more expensive. When assuming an average CO_2 price of 20-30 € per tCO_2e over 40 years, the cost difference disappears. A significantly higher CO_2 price may be required to provide incentives for new investments. Volume 2 will address the policy implications. When assuming 25% higher fossil fuel prices, a CO_2 price of € 40 per tCO_2e and 50% higher technology learning rates, the average household is €250 per year better off,

EXHIBIT 1

The cost of the decarbonized pathways and the baseline are likely to differ less than € 250 per year per household

Cost impact of the decarbonized power pathways per year per household[1]



1 Assuming all power costs get passed through to households
2 CO_2 price assumed of € 40/tCO_2e
3 IEA WEO 2009 '450 Scenario' assumptions for 2030, kept constant up to 2050
4 No carbon price
5 For all technologies. Learning rate is defined as capex improvement per doubling of cumulative installed capacity

vice versa. Superimposing 25% lower fuel prices, 50% lower learning rates plus €500 billion cost of change would result in a €300 higher annual cost per household than in the baseline (see Exhibit 1).

Both nuclear and fossil plants with CCS can be compatible with intermittent renewable energy sources. The combination of an expanded grid and increased back up plant capacity can balance a system that contains both some quantity of "baseload" generation as well as high levels of intermittent power. Load factors of nuclear and coal plus CCS remain high throughout the year, while curtailment of renewable energy remains below 3%.

Nuclear and/or coal-with-CCS plants are not essential to decarbonize power while safeguarding system reliability. A scenario with 100% renewable energy was evaluated. It includes 15% imports from North Africa and 5% from EGS, qualified as a breakthrough technology. It was evaluated in particular from the perspective of system reliability and was found to be capable of delivering the same level of reliability; the cost of electricity for this scenario contains higher levels of uncertainty and warrants additional study, but it does not appear to be dramatically more expensive than the main decarbonization pathways studied. In this pathway, storage and/or biogas are needed to keep emissions from OCGT plants at reasonable levels.

Delay by 10 years is not the better option if the 2050 target needs to be met. Although fundamental research will develop without large scale investments in renewable technologies, the cost improvements through scale effects are not realized if investments are delayed. Furthermore, the required investments prior to 2050 would have to be realized in 3 rather

18. Demand Response (DR) refers herein to a change up or down in a customer's electricity demand in response to dispatch instructions or price signals communicated to customers' premises; DR as used here does not reduce the energy delivered in a day, it time-shifts it within the day.

than 4 decades, increasing pressure on supply chains and funding, potentially leading to price increases due to shortages.

Distributed production does not take away the need for increased transmission. The analysis assumed up to 50% of solar PV is deployed on rooftops and the grid solutions reflect that assumption.

Storage facilities and electric vehicle-to-grid are not necessary but could improve the technical feasibility and economics. Storage beyond existing hydro and battery back delivery will reduce the need for grid and back up capacity.

ARGUMENTS THAT WOULD MAKE THE CASE MORE OR LESS ATTRACTIVE

There are a number of reasonable arguments that the case for transformation could be less attractive than portrayed in this report. Several of these warrant additional work to better understand the implications. This is particularly true for the effectiveness of new policy and the potential cost of implementation, the impact on distribution and gas infrastructure and the costs of change.

Similarly, there are a number of valid arguments why the case for transformation is more attractive than portrayed in this report. These may cancel out the challenges mentioned above to a greater or lesser extent. Of particular importance would be the impact of successful breakthroughs in technology and the reduced exposure to economic recessions caused by sudden increases in oil and gas prices.

Arguments for a less attractive case	Potential impact
1. Ineffective or counter-productive *regulation* could drive (capital) costs up, e.g., when energy efficiency measures fail, common standards are not adopted or investments are delayed due to lack of incentives.	*High*. Regulation is complex. Executing the transition well is critical. Misguided regulation could have devastating effects on the current system. For example, reduced success in energy efficiency could cut GDP by €300 billion in 2050.
2. Incremental costs for *distribution* are not incorporated. Individual house connections may have sufficient capacity, but on a street / neighborhood level, capacity could be insufficient to cope with EVs, heat pumps and back delivery of decentral solar (although demand response[18] will reduce peak load significantly). Costs for DR not included.	*High*. Estimates of the total distribution investment costs are €200 to 300 billion. However, grid upgrades are also needed in the baseline, so the incremental cost in the pathways will be less. If none of the required investments were required in the baseline, the cost of electricity could increase by an additional €5 to €7 MWh (5%).
3. Lack of *public support* could drive costs up and delay implementation, e.g., requirement for more underground cables and permitting issues for on shore wind and CO_2 storage.	*High*. Public opposition to, e.g., new overhead power lines, onshore wind farms, new nuclear plants and new CO_2 storage facilities has been and continues to be a major impediment.
4. The *cost of change* and the risk of (partial) failure are not incorporated. Large write-offs are common in industries under transition, e.g., UMTS, investments in fiber networks.	*High*. The magnitude depends on the effectiveness of regulation and the pace allowed.
5. The assumed technology learning rates and cost reductions may not be achieved (e.g., 15% learning rate for solar PV).	*High. A 50% reduction in learning rates across all technologies could increase the delta to the baseline by €10 per MWh.*
6. Implementation constraints could be more severe, e.g., Iberia/France interconnection, locations for wind onshore, solar, spatial requirements for heat pumps.	*Medium*. Alternative are available, e.g., laying part of the Iberia-France link underground or undersea; shifting the generation to more wind and less solar.
7. Incremental gas infrastructure costs for backup plants are not incorporated (primarily pipelines and storage)	*Medium*. Depending on the pathway, with lower residential and power demand for gas the current gas infrastructure might suffice.
8. Fossil fuel prices may be lower than anticipated by IEA.	*Medium*. A 25% price reduction reduces the transition benefits by less than €5 per MWh.
9. Increased demand could raise costs. If GDP increases faster than energy costs, consumers may decide to use more energy, not less	*Low*. Demand for decarbonized electricity will only increase if the costs are low and it is priced attractively.
10. Extreme *weather conditions* result in more year-on-year volatility in natural resources (e.g., wind lulls during winter when demand is high, potentially combined with cloudy skies)	*Low. Extreme weather conditions are included in the base case. Providing for conditions beyond these would cater for more than 1/20 year events adding < €1-2 per MWh.*

Arguments for a more attractive case	Potential impact
1. Innovation and related energy price reductions could create additional spillover effects in other sectors (e.g., energy-intensive industries)	*High*. Past innovations have had significant impact on productivity levels and contributed up to 1% additional GDP growth.
2. Technology learning rates are too conservative, or a *breakthrough technology* could emerge within the next 40 years.	*High*. Except for hydro, nuclear and conventional geothermal, all low/zero carbon supply technologies are emergent. Promising new concepts are being tested at pilot scale.
3. The exposure to *oil and gas price spikes* is lower in the decarbonized pathways. The risk of an oil or gas price triggered recession is therefore lower.	*High*. Academic studies have shown a direct correlation between price spikes and the onset of recessions. The pathways are significantly more resilient, saving 0.5% of GDP at the outset of such a crisis (over €70 billion a year).
4. The *total car cost of electric vehicles* or fuel cell vehicles will converge to the total car cost of a combustion engine car. Currently, a € 5,000 car cost difference is assumed to remain until 2050.	*High*. If the production cost of conventional and electric cars converges, it would result in an improvement in the decarbonized case of up to € 500 billion over forty years.
5. The assumed *technology mix* for 2050 is not fully optimized and the actual 2050 system could be more efficient and less costly than modeled in this study. The CO_2 abatement effect of CCS on co-fired biomass is not taken into account, which could be 5-10%	*Medium*. More detailed understanding of the regional and future costs will allow more optimal technology allocation.
6. The *cost of capital* could fall below 7% due to smart regulation, optimizing risk between investors and other stakeholders, enabling higher leverage and lower interest rates.	*Medium*. A reduction in the cost of capital from 7% to 5% improves the electricity cost by about € 5 per MWh.
7. Integration with *regions outside Europe* could lower the cost of the technology mix. Large potential for solar CSP from North Africa or geothermal power from Iceland or Turkey would provide firm dispatchable power. Russia could supply low cost biomass and biogas.	*Medium*. The potential contribution of North African solar CSP and Icelandic geothermal would reduce the need for balancing and back up capacity, but higher transmission requirements could reduce that benefit. There may be other potential benefits in developing these options.
8. Fossil *fuel prices* could be higher than anticipated by IEA in the baseline. The same fuel prices are used in the decarbonized pathways, yet a global *shift away from fossil fuels* could result in lower prices.	*Medium*. A 25% increase for fossil fuels would give a relative benefit of €5 per MWh.
9. Load shifting capability could be larger than currently assumed in the study.	*Low*. While reducing the need for transmission and backup further, the cost for these is only about 10% of total power investments.
10. Storage will become more cost effective than transmission and backup, reducing the need for transmission investments (e.g., EV batteries).	*Low*. The cost for transmission and backup is only about 10-15% of total power investments.

PART A:

CONTEXT, METHODOLOGY AND BASELINE

CHAPTER 1

CONTEXT AND OBJECTIVES

1.1 CONTEXT OF THE STUDY AND OBJECTIVES

Europe agreed to a target of 80% emission reduction in 2050 (compared to 1990 levels) in the G8 meeting in l'Aquila in July 2009 if global action is taken. In October 2009 the European Council set the appropriate abatement objective for Europe and other developed economies at 80-95% below 1990 levels by 2050. This study does not make any judgment on the target itself, but takes a reduction of at least 80% below 1990 levels by 2050 as a starting point.

The energy policy of the new Commission (for the period 2010-2014) will be instrumental in minimizing the effort, cost and duration needed to reach that target. Establishing a 2050-driven policy framework for the current period could therefore become one of the pivotal accomplishments of this Commission.

The objective of the study is to clarify short term requirements to achieve the 2050 ambitions, highlighting critical-path decisions that maximize the range of zero-carbon supply options and avoid high-carbon lock-ins, with levels of electricity supply reliability, energy security, economic growth and prosperity at least comparable to today's. It addresses at a high level the entire emission scope but looks in particular detail at the power sector.

The deeper focus on the power sector aims to answer the following questions:

- Is a fully decarbonized, equally reliable power supply technically feasible using known technologies? How could that be achieved over a wide range of resource mixes?
- How wide is the range of viable options? Do reliability or cost issues clearly favor specific decarbonization pathways? Or do other considerations drive the choice of pathways?
- Are these options affordable and what is the effect on Europe's economy?
- What are the similarities and differences between the pathways?

1.2 SCOPE AND ASSESSMENT CRITERIA

1.2.1 Scope of the report

The scope of the analysis included in volume I of this report is focused on two elements:

- **The description of a plausible way to realize an economy-wide GHG reduction of 80%** Baseline emissions are first projected and mitigation opportunities are derived across all GHG emitting sectors at the EU-27 level to meet the -80% 2050 target . The evolution during the period 2010-2050 is then derived using a "back-casting" approach.
- **The development and assessment of pathways to decarbonize the power sector** For the power sector, three main plausible pathways are

developed that each would realize a decarbonized power sector. The pathways range in share of renewable energy sources (RES, from 40% to 80%) versus fossil CCS and nuclear energy. Additionally, a pathway with 100% RES is assessed, and sensitivities on the relative shares of fossil with CCS and nuclear are performed. A detailed analysis for the implications on the transmission grid and balancing the system is included. In scope for the main pathways are the impact of decarbonized power on economic metrics; end-to-end implications on capital investments; import dependency; and commissioning and decommissioning requirements by technology by decade. Implications for other sectors are focused particularly on their link to the power sector through fuel shifts to decarbonized power.

The geographical scope of the study is the EU-27 plus Norway and Switzerland. This work assumes that Europe takes the global lead in emission reductions, but it also assumes that the rest of the world follows suit on a 450 Scenario trajectory[19]. This is particularly relevant when estimating the macro-economic impact as well as the potential for learning effects of technologies, as it is assumed that global investment drives down the costs of new technologies together with European investments.

Out of scope: a comprehensive assessment of all possible generation technologies; a detailed assessment of the cost of energy storage technologies; an optimization of the pathways based on future cost projections; policymaking and regulatory implications or recommendations (these will be covered in Volume II); implications on power and primary energy markets, pricing mechanisms, national energy strategies and secondary effects of decarbonization pathways on primary fuel prices; detailed trade-offs in the decarbonization of road transport (via electrification, hydrogen, biofuels or systemic measures like modal shift and urban planning) or building heat (via electrification, biomass/biogas, zero-carbon district heating schemes or other options); a detailed review of energy efficiency improvements available in all energy using sectors; or a study on the potential impact of the pathways on biodiversity, water requirements or other environmental issues.

1.2.2 Overall criteria for assessing the pathways

As already highlighted, climate is not the only element driving Europe's energy strategy. Indeed, three equally important goals emerge: sustainability (e.g., greenhouse gas emissions, resource depletion), prosperity (e.g., impact on the cost of energy, impact on GDP), and security of energy supply (e.g., European import dependency, self reliance in energy by region, risk of technology failure in the power sector). Security of supply includes the premise used in this work that the reliability of the electricity system cannot be compromised – pathways must maintain similar energy system reliability standards that are enjoyed today, using a benchmark standard of 99.97%.

On the other hand, the level of public acceptance, the related change required in the mindsets of all public and private stakeholders, as well as a consistency check with national energy policies are not included as the criteria for this work. Still, their importance cannot be understated, and the challenges they present will be highlighted in the latter part of this report, as well as in volumes II and III.

1.3 The added value of this report

While other organizations have issued reports on similar subjects, this project is an important addition to several dimensions of the debate:

- It covers the requirements on all sectors to reach the 2050 target of 80% GHG emission reduction without offsets, covering the implications on the power sector in detail; it is noteworthy in particular for its unique, in-depth analysis of grid system security and balancing analysis.

19. CO_2e concentrations projected by the IPCC to imply a global average increase in temperature of +2°C

- It describes a plausible, robust solution, with no significant technological or geopolitical “leap of faith” required. It is a fact-based approach without any pre-conditioned outcomes or biases. It therefore analyzes a range of pathways for the power sector that covers most opinions on the topic.

- It is comprehensive in scope, covering the EU-27 across all sectors, assessing in detail the implications for the power sector and particularly grid issues, providing a bottom-up cost assessment of a variety of pathways, and assessing macro-economic impact.

- The analysis was executed by a broad set of specialized consultants in cooperation with major industry players, the future investors in the required infrastructure, as well as influential NGOs. They have been involved in providing input to the key assumptions and reviewing the output of the analysis.

- While not funding the work, the European Commission and other European political stakeholders have been involved and given input on the objectives as well as on the output of the work. This report is also timed to support the EU decision calendar.

- Finally, it includes an intense public stakeholder engagement process with broad public communication tools.

CHAPTER 2
METHODOLOGY AND APPROACH

2.1 DESCRIPTION OF THE OVERALL METHODOLOGY

This work is a back-casting exercise, based on a series of analytical steps that take as exogenous inputs (i) a reduction of GHG emissions in EU-27 by 80% by 2050 compared to 1990 levels; and (ii) the delivery of a level of electricity supply reliability that is similar to that enjoyed today.

Baseline development The baseline leverages widely accepted external 2030 projections (mainly from the IEA WEO 2009 and Oxford Economics). The same trends in energy, power and emissions intensities are used to extrapolate these projections from 2030 to 2050. The baseline includes the development of the key parameters such as energy and power demand as well as GHG emissions. It is described in detail in Chapter 3.

Development of 80% reduction The feasibility of reaching the 80% reduction target by 2050 is described in detail in Chapter 4 and is assessed by deploying all cost-effective mitigation measures implemented to their maximum potential (up to a maximum cost of €100 per tCO_2e). This includes all abatement measures identified in the McKinsey Global GHG Abatement Cost Curve[20] beyond the energy efficiency improvements already incorporated in the baseline as defined in the IEA WEO 2009 report (1 to 2% per year). Beyond 2030, further penetration of CCS and energy efficiency measures is assumed. The requirements in buildings and transport for a further shift to non-emitting fuels such as biomass, hydrogen, zero-carbon CHP and carbon-free electricity were then assessed in order to reach the 80% target. Excluded are significant behavioral changes that would affect quality of life, such as major reductions in road transport. Emerging from this analysis is the conclusion that nearly full decarbonization of the power sector is an essential component of any 80% GHG reduction pathway.

Decarbonizing the power sector Power sector decarbonization is then analyzed in detail in Chapter 5, based on net final power demand projected after reductions from the baseline due to additional energy efficiency measures and increases due to electrification in transport and heating. Three main pathways for the power mix evolution have been defined to cover a wide range of prevailing views, and they are described in the following section. The grid balancing and security requirements for these pathways are analyzed extensively based on a generation dispatch model that optimizes the requirements for transmission, backup plants and balancing actions with an hourly resolution. The dispatch model considers a full range of dynamics of the power including hydro optimization, storage source utilization and the contribution from increasing the flexibility of demand. The decarbonized pathways are then assessed across a number of criteria: cost of electricity, overall investment required, energy security, macro-economic measures (e.g., GDP, sector growth, employment, inflation). The feasibility of a reliable 100% RES scenario was also assessed, and the cost of electricity for this scenario was evaluated with a wider range of uncertainty embedded in the results. Sensitivities on the changes in key parameters are described in Chapter 7.

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20. This report leverages the extensive work done by McKinsey on the maximum technical GHG abatement potential up to a maximum cost of €60 per tCO2e (and assumes further abatement potential up to €100 per tCO2e). For more details please refer to its report available on its website ("Pathways to a low carbon economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve").

2.2 BACKGROUND TO THE POWER DEEP DIVE

2.2.1 The value of a conservative approach using current technologies

This report is based on an approach that focuses on "current technology", which has been used in the three main pathways; additionally, chapter 7 explores further opportunities, including expanding to new geographies and potential technology breakthroughs that could ease the transition. The current technology approach is conservative in that it assumes 100% of the electricity is produced within the EU-27, Norway and Switzerland, and only uses technologies that are in late stage development or beyond[21]; but this is partially offset by the fact that these technologies are assumed to see improvements in cost and performance from where they are today, in some cases dramatically so, based on current industry consensus.

The "current technology" approach that is used throughout the key technical chapters of this report assesses how to solve the power decarbonization challenge by applying a broad mix of technologies and designing a power system to current reliability standards. This quantitative approach uses technologies that are in late stage development and demonstration stage or beyond to meet the extrapolated power demand from 2010 to 2050. Breakthrough technologies are excluded to make a robust case that depends on (close to) proven technologies. To further increase the robustness of the case, a broad mix of technologies is used, rather than relying on a few that may be expected currently to be lower cost. The future capital and operational costs and characteristics of these generation technologies are modeled based on learning rates that have been tested extensively with key industry players.

This approach allows a technical and economic assessment of whether an 80% reduction is possible with today's technologies and at what cost, with an indication of required investments by decade as well as an assessment of short-term measures that fit with the long-term objective. It compares these decarbonization pathways on economic and security of supply metrics.

Chapter 7 describes some of the potential "discontinuities", testing the impact of expanding to new geographies such as North Africa and describing possible breakthrough supply technologies in performance, costs and potential for 2050. It allows an understanding of what alternative futures might look like.

2.2.2 Pathways development and back-casting

Pathways development Three power pathways to an essentially carbon-free power sector were defined based on the following starting points: (i) to ensure at least 95% power sector decarbonization by 2050 compared to 1990 levels; (ii) to provide a level of electricity supply reliability that is similar to that enjoyed today; and (iii) is designed to be credible and *plausible* but not necessarily *optimized*.

The term *plausible* refers to several important elements of the power pathways. First, as described in the previous section, it means that they are based on a wide mix of commercially available or late-stage development technologies. This also means that technology mixes in the pathways are not meant to be predictive. Consequently, the total cost is not based on those technologies that are currently expected to be the lowest cost in 2050. This adds to the robustness of the solution (if one technology falls through, the system still works). Furthermore, a broad set of technologies and resources is more feasible to balance than concentration in a few technologies. Also, a basket of technologies allows deployment of appropriate technologies in those

21. The analysis does not attempt a comprehensive assessment of such technologies but rather focuses on those likely to be material at a European level by 2050; for instance, tidal power could be said to be in late-stage development, but its exploitable potential, though important in some regions, is relatively immaterial overall.
22. The solar industry has seen growth beyond 20% in the past few years.

locations where the relevant natural resource is most abundant. Limitations in (future) supply chains are also taken into account, e.g., solar PV industry growth is assumed to average about 20% year-on-year[22] through the full period, and biomass potential is limited to the sustainable potential identified for Europe. Additionally, there are economic trade-offs between investments in backup generation and transmission expansion and the annual balancing costs and generation curtailments.

Based on these criteria, the three pathways were designed to reflect a wide range of technically and economically plausible outcomes. They differ in the amount of electricity that is assumed to be produced by fossil with CCS, nuclear and renewable energy sources (RES) in 2050. The share of RES in 2050 in the three main pathways ranges from 40% to 60% and 80%. Fossil with CCS and nuclear supply the corresponding 60%, 40% and 20% share in each of the pathways. In order to limit the number of pathways addressed in the report and minimize confusion, the share covered by fossil with CCS[23] and nuclear is simply split evenly. Additionally, sensitivities were tested for each pathway in which the contribution of nuclear is increased by decreasing the contribution of fossil with CCS, and conversely the contribution of fossil with CCS is increased by decreasing nuclear. The plausibility of the 100% RES scenario was assessed primarily on system reliability dimensions, while the evaluation of the cost of electricity in this pathway has a higher degree of uncertainty embedded in the results.

Back-casting approach "Back-casting" means working backwards from 2050 to today. It is fundamentally different from forecasting, as the end-state is stipulated rather than derived. It can therefore help to highlight where current momentum must be broken and re-directed in order to arrive at a certain point in the future, while forecasting tends to extend current trends out into the future to see where they might arrive. The 2050 end-state is defined in each of the pathways as described in the previous section. The starting point is 2010. In the 60%, 80% and 100% RES pathways, by 2020 the EU reaches the production of electricity from RES roughly implied by the 2020 targets (34%). In the baseline and in the 40% pathway, RES penetration in electricity by 2020 reaches only the level forecasted in the baseline scenario of the IEA WEO 2009 of 29%. No intermediate RES target is assumed beyond 2020.

2.3 MACRO-ECONOMIC MODELING

Differences between the pathways are small as the impact on power prices is similar; thus for simplicity of presentation, except where stated otherwise the modeling results from the 60% RES pathway are cited here. The analysis links the results of the generation model, with its detailed description of the power sector under the three different pathways, with a macro-economic model describing the EU-27 economy. The model, developed by Oxford Economics, is a general equilibrium model with a focus on the supply side and on the energy sector. It has a long-term focus, making it better equipped to represent long-term potential growth paths under different circumstances rather than short-term dynamics and business cycles.

Power sector inputs include the share of different power generating technologies, the capital and operational expenditures associated with the power mix, and the implications on the cost of electricity (LCoE) for both the baseline and the pathways as well as the amount of fuel shift required in other sectors, such as industry and buildings, to meet the overall emission reduction target for the EU-27. Assumptions on energy efficiency measures are based on the McKinsey Global GHG Abatement Cost Curve.

The relationships between the different sectors in the economy, their inputs, outputs and weight in the economy are at the heart of the model and the latest version of the dataset that Oxford Economics has been developing for almost 30 years to model both the European and the world economies.

23. With an even split between coal and gas CCS, again meant to increase the robustness of the answer

Key assumptions on the characteristics of the economy in the rest of the world, particularly in terms of the energy sector, are based on the IEA WEO 2009 '450 scenario' which, while not as ambitious as the EU-27 decarbonization pathways, is regarded as an aggressive global scenario on action on climate change[24]. The 450 scenario assumes an increase in oil price to $87 per barrel in 2015 and to $115 in 2030 (all numbers in real terms). Gas prices increase to $10.50 per mmBtu in 2015 and $14.80 in 2030. Coal price increases to $91 per tonne of coal in 2015 and to $109 in 2030. This study assumes that fossil fuel prices remain flat beyond 2030. In the baseline modeling, the CO_2 price increases to $43 per tCO_2e in 2015 and $54 in 2030. In the decarbonized pathways, a global carbon market is assumed from 2020 onwards, assuming $50 per tCO_2e in 2020 and $110 beyond 2030 for the EU and OECD. For other major economies (which includes China, Russia, Brazil, South Africa and the Middle East) the CO_2 prices is assumed to be $65/t beyond 2030. ROW power sector decarbonizes less than Europe and builds 30% renewables by 2030.

It is assumed that until 2020, the rest of the world outside Europe sources half of their clean tech equipment from the EU. After 2020, the rest of the world is increasingly sourcing domestically, down to only 10% sourced from the EU by 2050.

2.4 STAKEHOLDERS ENGAGED AND THEIR ROLE

The assumptions in this report have been developed in close and intense collaboration with a total of more than 60 companies, institutions, NGOs and academia. They have been involved through topical workshops, broader ranging sessions, and bilateral meetings throughout the entire process.

Within this process, a panel of 9 academics was formed to review the insights, most of them focusing their research on the power sector. They have given their input to the overall outcome of the analyses, with the focus of their input on the direction of the project and potential next steps. This panel therefore had an advisory role, which means they did not do a full peer review and as such their input should not be taken as a full endorsement of the report or its findings. Next to this, 3 experts have been involved in a similar review session on the grid modeling performed with KEMA and ICL whereby their input was focused on the modeling input and methodology. These experts also had an advisory role, therefore the same applies to them as to the panel of academics as described above.

Finally, an Advisory Council consisting of politicians, academics and business leaders was created to review the findings of this report and help to position them in the larger political context.

The list of all these stakeholders is given in the *Acknowledgements* section in the upfront section of this report.

24. The IEA WEO 2009 450 scenario assumes the development of a global carbon market, first among OECD countries and later across the developed and developing world, together with a substantial uptake of renewable energy sources across the world.

CHAPTER 3
BASELINE DEVELOPMENTS

The baseline serves as a reference to which all key dimensions can be compared (e.g., the cost of electricity, emission reductions, reduction in the use of fossil fuels). This baseline is a projection based on today's world. It is based on reputable sources like the IEA's WEO 2009, UN or Oxford Economics, while detailed breakdowns and interpolations have been developed by the project team. Economic growth by sector and region is based on Oxford Economics and WEO 2009, and shares of energy and power demand and supply by region based on PRIMES. Growth in demand and emissions from 2030 to 2050 is extrapolated using similar trends in energy, power and emissions intensity as 2010 to 2030.

Key developments for overall GDP, energy demand, power demand and GHG emissions from 2010 to 2050 are assumed as follows:

- *Overall GDP is assumed to grow from €10 to 22 trillion (with a stable population)*
- *Energy demand is assumed to grow by 10%, de-linking from GDP growth based on large efficiency improvements of 1% to 1.5% year-on-year*
- *Power demand increases by 40% with lower efficiency improvements (about 1% year-on-year)*
- *GHG emissions, which have decreased by about 10% since 1990 until 2010, are assumed to stay relatively flat until 2050, with significant emission intensity improvements*

This assumes that climate policies currently in force are carried through, but no additional policies are implemented. Assumed policies include: the EU-ETS, with carbon prices for industry, power and aviation (by 2012); the 20-20-20 policy package, including significant energy efficiency improvements (1-2% per annum); transportation efficiency targets; and some CCS pilot projects.
The baseline assumes current technology in road transport and building heating.

3.1 ENERGY DEMAND BASELINE

3.1.1 GDP AND POPULATION

From 2010 up to 2050 population of the EU-27 is assumed to remain stable with around 500 million citizens, while GDP is assumed to more than double, growing by 1.8% year-on-year: from about €10 to 22 trillion in real terms, in line with IEA projections. This implies that on average the GDP per capita will also double, increasing the purchasing power of European citizens.

3.1.2 ENERGY INTENSITY

Energy intensity is defined in this report as the amount of energy required per euro of value added. The developments in energy intensity for the EU-27 are detailed by sub-sector in Exhibit 2 on the next page. Industrial sectors will remain the most energy intensive, but improvements of close to 1.5% year-on-year are assumed. This leads to intensities that are on average 50% lower by 2050 compared to 2010.

3.1.3 RESULTING TOTAL ENERGY DEMAND

Demand growth driven by economic growth is largely offset by improvements in energy intensity, together with the increasing weight of the non-energy intensive sectors (such as services) in the economy. The net growth in energy demand from 2010 to 2050 is assumed to be about 10%, reaching a total of 1,400 Mtoe[25] in 2050. This happens in parallel with a doubling of GDP during the same time period.

EXHIBIT 2

Energy and power intensity reduce by 1% to 1.5% per year

Mtoe per € of sector value added[1]

Service
Industry
Residential & Transport

Sub-sectors	Energy intensity 2010	Energy intensity 2050	Energy intensity CAGR[2]	Power intensity 2010	Power intensity 2050	Power intensity CAGR[2]
Basic metals	1,080	585	-1.5	274	189	-1.0
Industry overall	118	70	-1.3	39	28	-0.8
Electronic engineering	66	37	-1.4	37	24	-1.1
Mechanical engineering	65	50	-0.6	N/A	N/A	N/A
Construction	55	33	-1.3	20	13	-1.1
Retail trade	37	23	-1.2	28	20	-0.9
Wholesale trade	34	21	-1.2	15	11	-0.9
Transport	33	21	-1.2	N/A	N/A	N/A
Residential	33	18	-1.6	10	6	-1.1
Services overall	20	11	-1.5	10	7	-1.1
Finance	12	7	-1.3	6	4	-1.0
Business Services	10	6	-1.2	6	4	-0.8

1 Value added is GDP for the whole economy; value added in industry; value added in services; GDP for transport; and households income for residential
2 Compounded Annual Growth Rate
SOURCE: IEA WEO 2009; team analysis

Exhibit 3 describes developments by sector for total energy, as well as specifically for power.

3.2 POWER DEMAND BASELINE

3.2.1 Power intensity

The power intensity developments follow a similar trend to the total energy ones, although with lower efficiency improvements, assuming a year-on-year decrease at an average of 1%. Industry sectors remain the most power intensive but see significant improvements up to 2050.

3.2.2 Resulting power demand

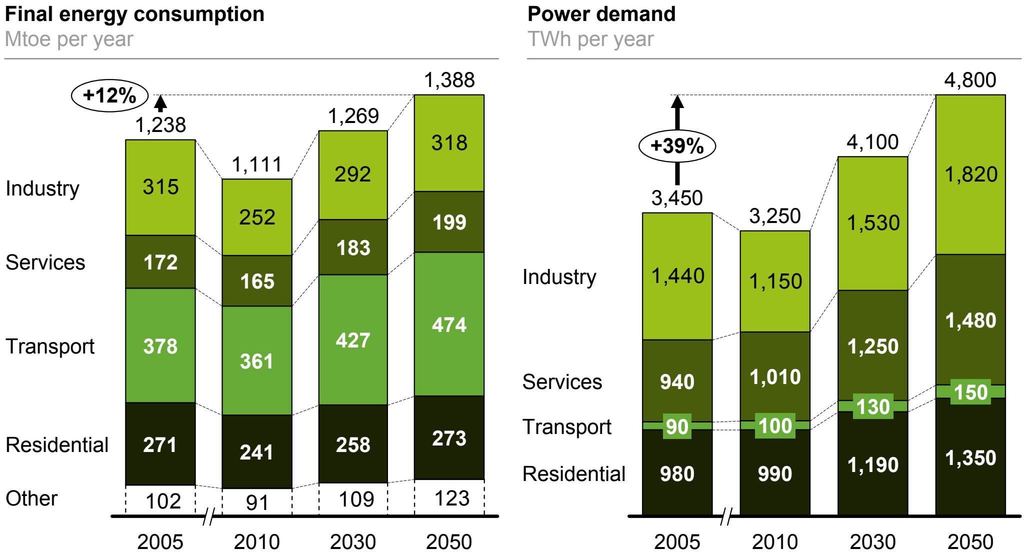
The improvements in power intensity will offset increased energy usage driven by the doubling in GDP, with power demand for the EU-27, Norway and Switzerland climbing roughly 40% above its 2010 value, reaching a power demand in 2050 of about 4,800 TWh, as highlighted in Exhibit 3. This increase is higher than the energy demand one as year-on-year improvements are lower.

25. Million tons of oil equivalent

EXHIBIT 3

Power demand grows by ~40% over 45 years in the baseline

EU-27, Norway and Switzerland energy and power demand



SOURCE: IEA WEO 2009; team analysis

3.3 ENERGY AND POWER SUPPLY

3.3.1 TECHNICAL DEVELOPMENT OF GENERATION TECHNOLOGIES

The current and potential future cost and performance, developments and the maximum capacity for Europe have been established by technology through industry participation workshops. Equipment manufacturers, utilities, TSOs, NGOs and academia were invited to share perspectives and offer public reports. The numbers used in this report reflect mostly the consensus view, though in some cases a reasonable mid-point has been struck among different viewpoints.

Future cost developments are estimated through applying learning rates. For established technologies this is a yearly rate of improvement per year, for new technologies this is a reduction in cost per doubling of cumulative installed capacity. In the latter case, both the current and additional capacity is assumed to be the European capacity, implicitly assuming that the global development is in line with this. Exhibit 4 gives a detailed overview of capital costs per kW of installed generating capacity and their evolution in the 60% RES pathway.

The basic assumption is that all the power consumed in Europe is also produced within Europe; only the assessment of the 100% RES scenario assumes imports (from North Africa). Tables summarizing additional technical parameters can be found in the online Appendices.

EXHIBIT 4

Learning rates are applied to estimate future capex

Type of generation	Generation technologies	Learning rate[1] Percent	Yearly Reductions Percent	Capex 2010 €/KW	60% RES / 20% nuclear / 20% CCS Capex 2030 €/KW	Capex 2050 €/KW
Fossil	▪ Coal Conventional		0.5	1,400-1,600	1,250-1,450	1,150-1,350
	▪ Gas Conventional		0.5	700-800	650-750	600-700
	▪ Coal CCS[2]	12		2,700-2,900 [3]	2,000-2,200	1,750-1,950
	▪ Gas CCS[2]	12		1,500-1,600 [3]	1,000-1,200	900-1,100
	▪ Coal CCS[2] retrofit	12		1,250-1,450 [3]	600-800	500-700
	▪ Gas CCS[2] retrofit	12		750-950 [3]	350-550	300-500
	▪ Oil		0.5	750-850	700-800	600-700
Nuclear	▪ Nuclear[4]	3-5		2,700-3,300	2,700-3,300	2,600-3,200
RES						
Intermittent	▪ Wind Onshore	5		1,000-1,300	900-1,200	900-1,200
	▪ Wind Offshore	5		3,000-3,600	2,000-2,400	1,900-2,300
	▪ Solar PV	15		2,400-2,700	1,000-1,400	800-1,200
Non-Intermittent	▪ Solar CSP	HC[5]		4,000-6,000	2,900-3,500	2,200-2,600
	▪ Biomass dedicated		1.0	2,300-2,600	1,600-1,900	1,300-1,600
	▪ Geothermal		1.0	2,700-3,300	2,000-2,400	1,800-2,200
	▪ Hydro		0.5	1,800-2,200	1,750-2,000	1,500-1,900

1 Percent cost reduction with every doubling of accumulated installed capacity
2 Learning rate of 12% applies to CCS part; Learning of coal/gas plant identical to coal/gas
3 starts in 2020, additional capex to conventional plants for retrofits
4 France starts with lower capex of 2750 €/kWe; LR on Gen II and Gen III separated
5 Hardcoded input based on workshop including storage

Fossil fuel plants

Coal plants and combined cycle gas plants ("CCGT") currently deliver the largest share of electricity production in Europe. Both types of plants are considered firm dispatchable sources of power (see Glossary for definitions). Coal plants have higher fixed costs than CCGT and lower operating costs, and CCGT plants are generally able to start up faster and at lower cost than coal plants; as a result, coal plants tend to be operated as "baseload" plants (plants that operate generally around the clock, at least at part load), while CCGT plants tend to be operated as "mid-merit" plants (turning up and down, and even on and off, with normal daily fluctuations in demand). The assumed "economic life" (defined here as the average depreciation life) for coal plants is 40 years and 30 years for CCGT plants. Efficiencies for new gas plants are assumed to grow from 58% in 2010 to 60% in 2050; for coal it grows from 45% to 50%. Continuous annual cost reduction of 0.5% is assumed on capex. Coal and gas reserves are expected to be sufficient through 2050 for the levels of consumption envisioned. A mix of both hard coal and lignite is assumed in the fuel mix. Bituminous (hard) coal production is on the decline in Europe, while lignite production is more resilient and important throughout Europe, with reserves and mining capabilities throughout most of Central and Eastern Europe. Cost of lignite is assumed to be the market price for hard coal; in practice lignite prices vary significantly based on local conditions. New hard coal plants emit 0.77 tCO_2 per MWh, new lignite plants emit 0.95 tCO_2 per MWh, and new CCGT plants emit 0.36 tCO_2 per MWh (existing plants perform worse).

Coal-CCS and gas-CCS plants Carbon Capture and Storage ("CCS") refers to the separation of CO_2 from other components, liquefying it and storing it in secure locations (primarily geological formations). It can in theory be applied to any plant involving the combustion of carbon-based fuels, but here it is applied only to coal and CCGT plants. The baseline assumes no significant CCS deployment. For the decarbonized pathways, CCS is assumed to be progressively available from 2020 onwards, both for coal and for CCGT plants. All fossil fuel plants built after 2020 are assumed to be equipped with CCS. Coal plants built in the period 2011-2020 are assumed to be retrofitted with CCS in the 2020-2030 decade. Adding CCS to power plants will reduce CO_2 emissions by 90% and reduce efficiency by 20%[26]. CCS may reduce plant operational flexibility but is not assumed to do so here. The quantity and suitability of storage options is not assessed as part of this project, and indeed these are important questions for the ultimate potential for CCS deployment; existing studies have identified ample amounts of promising geological storage opportunities, sufficient in theory to accommodate the envisioned quantity of production in any of the pathways studied, but how much liquefied CO_2 can actually be injected and retained in various formations remains unclear. Priority will be given to storage requirements for heavy industry (since there are few if any alternative abatement options), which may in practice restrict the amount of CCS that can be sustained for power generation, particularly in the 40% RES pathway where fossil with CCS is expected to supply 30% of EU power demand. A learning of 12% is assumed for every doubling of installed CCS capacity through 2050, which is expected to bring CCS abatement costs down to €30-45 per tCO_2. Transport and storage cost are assumed at €10-15 per tCO_2e abated. These assumptions are consistent with the McKinsey report "CCS, Assessing the economics" of 2008.

Nuclear

Nuclear power plants currently provide approximately 30% of European power production. They have high fixed costs and low variable operating costs, which means that they tend to be run at full rated load around the clock and have limited operational flexibility compared to coal and CCGT plants. For this reason they are sometimes referred to as "baseload" plants. The new nuclear power plants are assumed to be of Generation-III technology, which incorporates a number of intended design improvements over previous generations of nuclear technology. It is assumed that industry could ramp up as necessary to meet the rate of expansion envisioned in all of the pathways. Availability of fuel is not a limitation under any of the pathways; prices for uranium ore may rise as lower-cost reserves are depleted over the next four decades, but fuel cost represent just a small proportion of the overall cost and therefore a rise in fuel cost will have little impact. The lack of long term storage facilities for high level waste has not been addressed by this study. In Europe, only Sweden and Finland have selected sites for long term storage and started constructing repositories. Nuclear fission is a mature technology; a learning rate of 3 to 5 % is applied to the portion of the capex that is new to Gen-III designs. This leads to a cost reduction of less than 10% over 40 years.

Renewable energy sources

Biomass power plants are similar to coal plants, except that they burn plant matter and other biological material as fuel. In many cases biomass is actually burned in limited quantities in coal plants, called "co-firing". Like coal plants, they are firm dispatchable resources, though when they are used to provide heat for non-power uses (as they often are) their operational flexibility for power production can be restricted. They are assumed to be carbon neutral, which means their potential as a zero-carbon resource is limited by the availability of sustainable supplies of biomass. Dedicated power plants as well as CHP plants are assumed to generate up to 250 MW. A yearly reduction on the capex cost of 1% per year is assumed. Chapter 4 will describe the assumptions on biomass supply and consumption across sectors in detail, but the maximum potential for biomass fired power production is assumed to be 12% of European demand in 2050. The biomass used in power is assumed to be burnt in power plants where CCS cannot be applied, being too remote from the CCS transport network. This is a conservative estimate: in the future, when coal plants will be equipped with CCS, co-firing biomass could generate "negative emissions" – capturing emissions from a carbon neutral source. Including the effect of lifecycle emissions, this could lead to an additional 5-10% reduction (of the current level of power CO_2 emissions).

26. For example, the efficiency of a bituminous coal plant would drop from 50 to 41% (in 2020, for a new built 900 MW plant with post-combustion CCS)

Concentrated solar power (CSP) plants use mirrors/lenses to concentrate sunlight and generate heat, which powers a turbine. Unlike solar PV, which utilizes all ambient solar energy, CSP uses only the solar energy that strikes the mirror surface at an 90° angle (called direct normal insolation, or "DNI"), which restricts the geographical areas in which it is commercially attractive. It is assumed that these plants will be equipped with six hours worth of thermal storage, a technology that is already in commercial demonstration in Spain. This allows CSP to be operated effectively as a firm, dispatchable resource for up to 15 hours a day, depending on the quality of the local solar resource. *Current* cost estimates are based on parabolic trough technology, which has a limited amount of commercial experience, but competing variations (central receiver, linear Fresnel and Stirling dish) offer significant potential for improvements in cost and performance, which is reflected in the learning rate potential. The potential for solar CSP in Europe is assumed to be about 300 TWh per year due to a limited range of geography with high direct normal insolation rates, limited area available for development and terrain limitations. Most of the potential is located in Iberia, with smaller potentials elsewhere in Southern Europe. Vastly more potential for CSP is technically accessible in North Africa and the Middle East.

Geothermal power relies on heat from the earth's core to provide a steady supply of energy, making it a firm, dispatchable resource. Conventional geothermal requires naturally wet subsurface rock. The potential for conventional geothermal is assumed to be limited to about 2% of European power demand due to limited suitable and economic locations. More potential exists in Iceland, which is technically accessible to Europe, but this has not been used in any of the pathways. Conventional geothermal is a mature technology; a capital cost reduction of 1% per year is assumed. Enhanced Geothermal, which involves injecting water deep into dry geothermal reservoirs to be flashed into steam and spin a turbine, is assumed to be a breakthrough technology, though it is promising enough that it has been deployed in the 100% RES pathway.

Hydroelectric power currently provides the largest share of power produced from renewable sources. Most of the available and economical sites have already been commercialized and only a limited increase of hydro power is assumed, in line with the IEA WEO 2009 projection. Electricity from dammed water is dispatchable and firm to the extent permitted by the dependability of the annual upstream precipitation and the capacity of the reservoir. European hydro plants have unused potential for optimization of their storage potential, and the decarbonization pathways assume that the storage potential of the existing hydro system is optimized.

Pumped storage hydro is a bulk energy storage facility that shifts energy in time (typically over periods of hours) by pumping water from a lower reservoir to an upper reservoir during periods of low demand or surplus supply, and releasing the stored water through a turbine during high demand periods (pumped storage hydro, or "PSH"). In 2007 the EU had 38 GW net capacity of pumped storage out of a total of 140 GW of hydropower and representing 5% of total net electrical capacity in the EU (Eurostat, consulted August 2009). Rated power of these facilities range from several tens of MW up to almost 3,000 MW. As these systems require mountainous areas this type of storage has some geographical limitations and therefore cannot always be placed at locations where it might be needed most. Innovative concepts on artificial islands in the sea have been launched in The Netherlands by KEMA, Lievense and Das (Energy Island) as well as in Denmark by Gotlieb Paludan and Risø (Green Power Islands). There is some potential to expand the existing fleet of PSH plants however this has not been assumed in any of the pathways beyond what is assumed to be added in the baseline.

Run-of-river hydro uses only the natural flow and elevation drop of a river, diverted through a turbine, to generate electricity. Therefore, the output of the power plant is tied directly to the short term flow rate of the river and is therefore an intermittent resource. Run-of-river hydro is not a significant source of electricity today and is considered effectively fully exploited.

Wind power production has grown steadily since the early 1980s and that growth has accelerated over the last few years, today constituting approximately

5 % of European power production, nearly all from onshore production. Large offshore wind parks are currently being developed in the North Sea. Technology development continues, leading to larger wind turbines and higher load factors. Onshore turbine sizes are assumed to increase to 3 MW in 2030 and offshore turbines to 5 MW in 2020 and to 10 MW in 2040. Improvements due to technology development and larger plants increase load factors from 25% to 30 % for onshore new builds today to about 35% in 2050, while offshore load factors increase from 37% today to 45% in 2050. A wind power plant is an intermittent resource. With improvements in technology its load factor has risen in recent years, and with improved forecasting its predictability has improved for day-ahead planning purposes, but over longer periods of time an individual wind farm's production is essentially random. Currently, offshore parks are built in depths less than 50 meters and are based on fixed foundations. Floating platforms are expected to become economical but are not required to meet the capacity assumed in the decarbonized pathways and are not included in either capacity or cost estimates. For onshore and offshore technologies a cost decrease per doubling of cumulative installed capacity of 5% is assumed. As the starting installed base of offshore wind is lower it will see larger cost reductions.

Solar photovoltaic (PV) load factors are assumed to be 17% for the southern part of Europe and 10% for the northern part. While PV load factors are lower than for wind (wind can blow any time, but the sun shines only during the day), an individual PV installation tends to be somewhat more predictable. Like a wind plant, however, it is considered an intermittent resource for system planning purposes, since it is directly dependent on the amount of ambient solar energy available locally at any given moment. A cost reduction of 15% per doubling of cumulative installed capacity is assumed, based on a workshop and follow up discussions with industry players. This is a weighted average of higher learning rates for the module and limited learning for the balance of system and installation costs. The assumed forward learning rate is lower than historic cost reductions, which have decreased at a learning rate of 22% since 1975. Rooftop PV and ground mounted PV are expected to be developed simultaneously, with rooftop PV showing a 25% higher cost compared to ground mounted PV. On a project basis, some 2010 capex quotes are already lower than the assumed capex costs for 2010 in Exhibit 4 above. This indicates that performance and cost continue to develop at a rapid pace.

Grid For the transport of the electricity from the power plants to the end consumer an average loss of 10% is assumed. A complete description of the grid input assumptions is included in chapter 5.

A more detailed description of the technical parameters assumed for the generation technologies, including opex and ramp up and down rates, is included in the online Appendices.

3.3.2 Power generation and capacity mix

Because the lifetimes of power plants range from 25 to 45 years, the transition from the current supply portfolio to a decarbonized supply portfolio will require the better part of the entire period up to 2050 if a significant quantity of stranded costs from early plant retirements is to be avoided. Nonetheless, by 2040 only 700 TWh of production (mostly from hydro plants) will remain from today's existing capacity and capacity under construction – assuming all plants are retired at the end of the economic lives assumed in this study[27]. By 2020, new capacity able to generate 900 TWh per year needs to be in commercial operation in order to meet projected demand. This growing shortfall in production over time is served in the baseline by a mix of new resources based on the high level mix described by the IEA WEO 2009, as illustrated in Exhibit 5 on the next page.

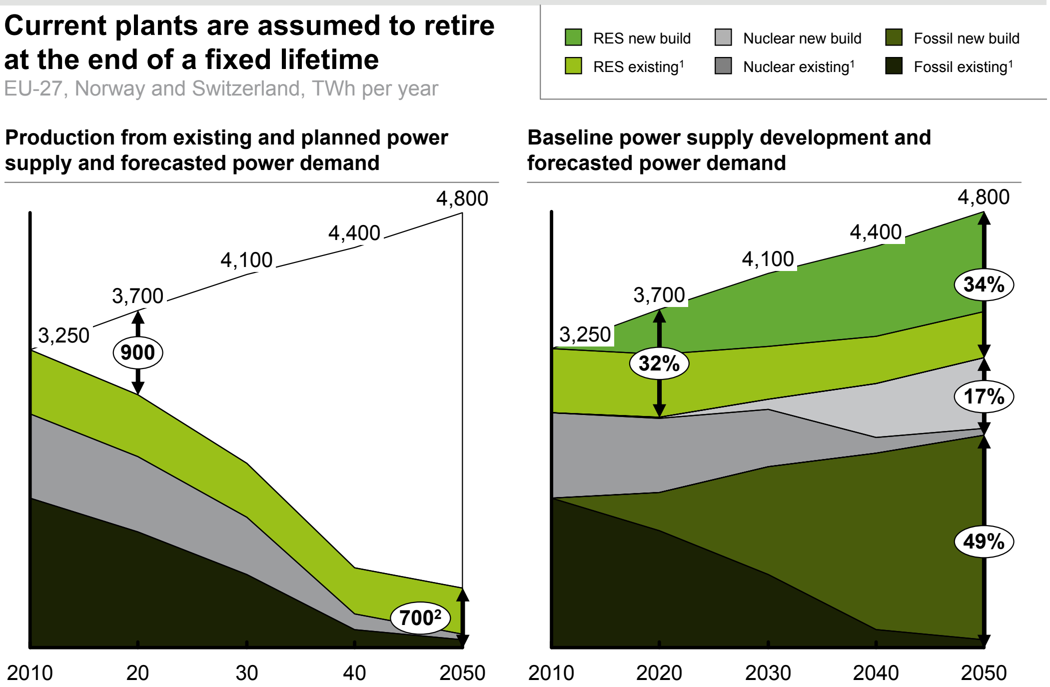
The build up and ramp down of existing generating capacity is based on actual individual plant data regarding their construction dates and the assumed lifetime. No early retirements have been assumed. The share of renewable energy in the baseline increases

27. Refer to the online Appendices for the economic lives assumptions used for each technology

EXHIBIT 5

Current plants are assumed to retire at the end of a fixed lifetime

EU-27, Norway and Switzerland, TWh per year



1 Existing capacity includes plants under construction
2 RES capacity remaining in 2050 is entirely made of hydropower plants

over time, reaching 32% for the EU-27 plus Norway and Switzerland (29% for EU-27) of production by 2020, consistent with the reference scenario of the IEA WEO 2009 for Europe. It then increases to 34% by 2030 where it is extrapolated to plateau through 2050. In the baseline, 49% of the production in 2050 is still fossil fuel based (without CCS). Nuclear power provides the remaining 17% of production.

3.3.3 Cost for primary fuels (oil, coal and gas)

The costs of oil, coal and gas up to 2030 have been taken from the IEA WEO 2009 (from their *'450 scenario*', which has lower costs than the *'Reference scenario'*) and are given in the table on the next page. Beyond 2030 prices are assumed flat in real terms (i.e., increasing at the general inflation rate). This is likely conservative as a baseline assumption, as it assumes that none of the three primary fossil fuels used will become significantly scarcer in the two decades beyond 2030. High and low variations are used in the section on sensitivities in the cost of electricity in chapter 6.

3.4 Economy-wide EU-27 emissions baseline

Total GHG emissions in the EU-27 in 2007 were approximately 5.7 $GtCO_2e$, but they are expected to be 5.2 $GtCO_2e$ in 2010, down because of the economic downturn. Emissions from the power sector constitute about 25% of the total, 25% is due to transportation, 20% to industry, 20% to buildings and the rest is split between agriculture and waste. Three countries – Germany, Italy and the UK – contribute half of all emissions from the power sector, with France contributing substantially less due to its extensive nuclear infrastructure. This section sets out the methodology adopted in the study to project emissions over the 2010-2050 period.

Table 1: Fuel cost assumed based on the IEA WEO 2009

Fuel	2009 actual	IEA WEO 2009	
	Yearly average	2015	2030
Oil (USD per barrel)	59	87	115
Coal (USD per tonne)	70	91	109
Gas (USD per mmBtu)	8.9	10.5	14.8
Uranium (€ per MWh)	8.0	8.0	8.0

3.4.1 Power emissions

Emission projections for the power sector are derived from the power generation mixes described in chapter 2 and detailed further in chapter 5. To arrive at total power emissions, production per technology was multiplied by the emissions per kWh based on IEA estimates. Total emission projections match closely the power sector emission projections from the IEA WEO 2009.

3.4.2 Total emissions

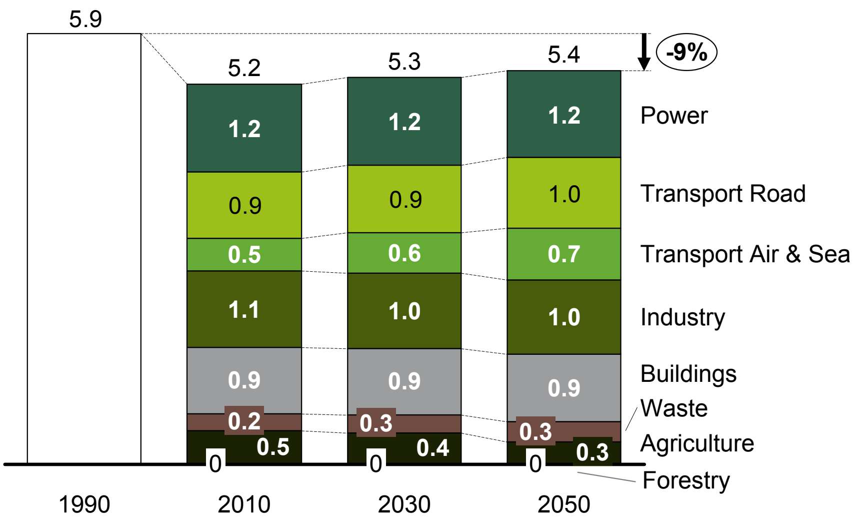
Emissions from non-power related sectors are obtained from two main sources: the IEA WEO 2009 (mostly for trends in industrial emissions) and from the McKinsey Global GHG Abatement Cost Curve analysis of the buildings sector, transport, and all non-energy related emissions, as these are not covered
by the IEA. The projections fully account for the slow-down in emissions due to the recent economic crisis.

The emission intensity of the economy, which is the amount of GHG emitted per unit of GDP, declines over time as a result of the implementation of energy efficiency, a shift away from energy-intensive sectors and a shift to lower carbon power production sources already included in the baseline. On average, the economy reduces the amount of GHG required per unit of output at a rate of 1.8% per year. This is a higher rate than has recently been achieved. All sectors reduce their emission intensity, industry leading with a rate of reduction of 2.3% a year. The emission intensity of the economy is assumed to continue along similar trends beyond 2030; projected GDP growth is used to obtain projections for emissions. Total emissions are expected to grow in the baseline but at a slower rate than GDP growth, from 5.2 $GtCO_2e$ in 2010 to 5.3 $GtCO_2e$ in 2030, rising to approximately 5.4 $GtCO_2e$ in 2050 (see Exhibit 6 on next page).

EXHIBIT 6

Emissions are assumed to grow slightly in the baseline after a drop before 2010

EU-27 total GHG emissions, $GtCO_2e$ per year



SOURCE: McKinsey Global GHG Abatement Cost Curve; IEA WEO 2009; WRI (CAIT 2009) Oxford Economics for GDP 2030-50; team analysis

PART B:

TECHNICAL SOLUTIONS AND COST OF ELECTRICITY

CHAPTER 4

REACHING THE 2050 TARGET OF -80%

4.1 MAXIMUM ABATEMENT WITHIN SECTORS

To reach -80%, the first step is to identify emission abatement measures beyond those already included in the IEA WEO 2009. All measures identified in the McKinsey Global GHG Abatement Cost Curve through 2030 with abatement cost of less than € 60 per tCO_2e are assumed to be implemented fully. Further penetration of CCS and efficiency improvements is implemented between 2030 and 2050, increasing this cost to € 100 per tCO_2e. This approach includes known technologies and leaves out potential breakthroughs (e.g., in industry processes or agriculture). Taken together, all of these measures would lead to a GHG reduction of approximately 60% by 2050. The following measures are included beyond those embedded in the IEA WEO 2009:

- The power sector is assumed to implement essentially carbon free technologies. By 2050, 95% abatement is assumed in the analysis (further explained in chapter 5). Technically the reduction in emissions is only limited by the net abatement efficiency of CCS power plants (only 90% of the CO_2 is assumed to be captured with CCS) and the potential remaining need for highly flexible open-cycle gas turbines (OCGT) to provide back-up capacity to maintain system security. One alternative would also be to use biomass either in dedicated biomass-with-CCS plants or co-fired in coal plants with CCS, creating in effect negative GHG emissions to close the gap and make the power sector completely carbon-free. This has not been assumed in the analysis, though it is a technically feasible alternative.
- In industry sectors the baseline already assumes a large share of energy efficiency improvements. Beyond these improvements a rollout of CCS is absolutely critical to reach the 80% 2050 target as efficiency opportunities reach a limit. CCS is applied to 50% of heavy industry in Europe (cement, chemicals, iron and steel, petroleum and gas) by 2050. The cost for CCS in industry is unclear at this time; it is assumed to be around 100 € per tCO_2e abated.
- 20% additional emission reductions are assumed beyond the significant improvements in the baseline in the road transport sector and 30% additional reductions in the air & sea transport sector by 2050, mainly through technology development and energy efficiency measures.
- The buildings sector reduces its direct CO_2e emissions by 45% beyond the baseline improvements through energy efficiency measures such as insulation.
- The waste sector can become carbon neutral by recycling and composting waste as well as capturing produced methane for electricity production.
- Improved agricultural practices and livestock management practices can lead to a 20% GHG reduction in the agriculture sector. This excludes biological carbon sequestration measures, which

can decrease net GHG emissions in the early years but are widely assumed to have become saturated after 20 to 30 years and would therefore not be sustainable up to 2050.

- In addition, forest management, degraded forest restoration and pastureland afforestation is assumed to represent a combined carbon sink of 250 $MtCO_2e$ per year by 2050 within the EU. Carbon sinks related to forestry last longer than agricultural carbon sinks.

4.2 ADDITIONAL DECARBONIZATION FROM FUEL SHIFT

To reach the target of 80% GHG reduction by 2050 additional cross-sectoral optimization is required. In the transport and buildings sectors clean fuels such as biofuels or biomass, carbon-free hydrogen and decarbonized electricity must replace fossil fuels extensively. In industry, the same happens but within the limits of those processes requiring heat, which cannot all rely on electricity because of high temperature requirements and which in many cases are too small to justify the application of CCS.

Use of biomass across sectors Biomass is limited in supply to 5,000 TWh in primary energy value (approximately 12,000 million tonnes per year, including 20 to 30% likely imported to Europe, particularly bio-kerosene to be used in aircraft). This assumption is based on a comprehensive review done by McKinsey on the availability of global biomass[28]. This study takes into account constraints on the availability of biomass, such as water scarcity and the need to avoid competition with food. Some or all of this potential biomass is consumed mostly in the following sectors: road, air & sea transport, buildings, industry, and power. Clearly multiple combinations exist to leverage this biomass:

- Biomass can be used in a centralized way in the power sector. This allows an efficient use of biomass and can also lead to potential additional abatement by capturing and sequestering the carbon, effectively converting these plants into carbon sinks. However, large dedicated biomass plants, which are most suitable for CCS, require extensive and complex supply logistics that can drive up the cost of feedstock.

- Co-firing biomass into coal-CCS plants leads to attractive economics, as the capex of coal plants is not significantly affected by the addition of a limited amount of co-firing. Assuming 15% co-firing on all coal-CCS plants in the 40% RES pathway (which includes 15% of production from coal-CCS plants) leads to a 2% of the total production mix from biomass and requires about 300 TWh_{th} of biomass (primary energy).

- Another option is to leverage biomass for sectors that are difficult to abate with other technical options, such as trucks and aircraft. Electrical drives are currently not suited for heavy-duty vehicles, as the batteries required are too heavy and expensive, so trucks will need to rely on other options, including biofuels to some extent, for decarbonization. Similarly, air transport is expected to rely on bio-kerosene for decarbonization[29].

This report is based on the following set of assumptions: 40% of the biomass potential is assumed to go to road transport, another 20% is assumed to be used for air and sea transport, and the remaining 40% is assumed to be used for power generation[30]. This study assumes conservatively that the biomass for power generation is required in small isolated plants across Europe where a CCS network would be too costly to implement. However, should this not be necessary, this biomass could be

28. An overview of this study can be found in the following publication: Biomass: mobilizing a sustainable resource; Chapter in “Sustainable Bioenergy” published by Environmental Finance; February 2010; B. Caesar, N. Denis, S. Fürnsinn, K. Graeser, U. Kempkes, J. Riese and A. Schwartz
29. Batteries are unattractive, as is ethanol, which has a fuel density too low for jet engines. Even so, in a reasonable time horizon ethanol may be commercially converted to bio-jet fuel either by microbial conversion (still in pilot testing phase) or by thermo-chemical reaction. These options are not currently commercially available and are likely to be expensive in the earlier years..
30. This represents 5,000 TWhth and this maximum potential is consumed in the 80% RES pathway, while other pathways assume 30% less.

co-fired in CCS-coal plants. If 25% of the biomass used in the power sector was co-fired it would bring an additional 5% of decarbonization to the power sector.

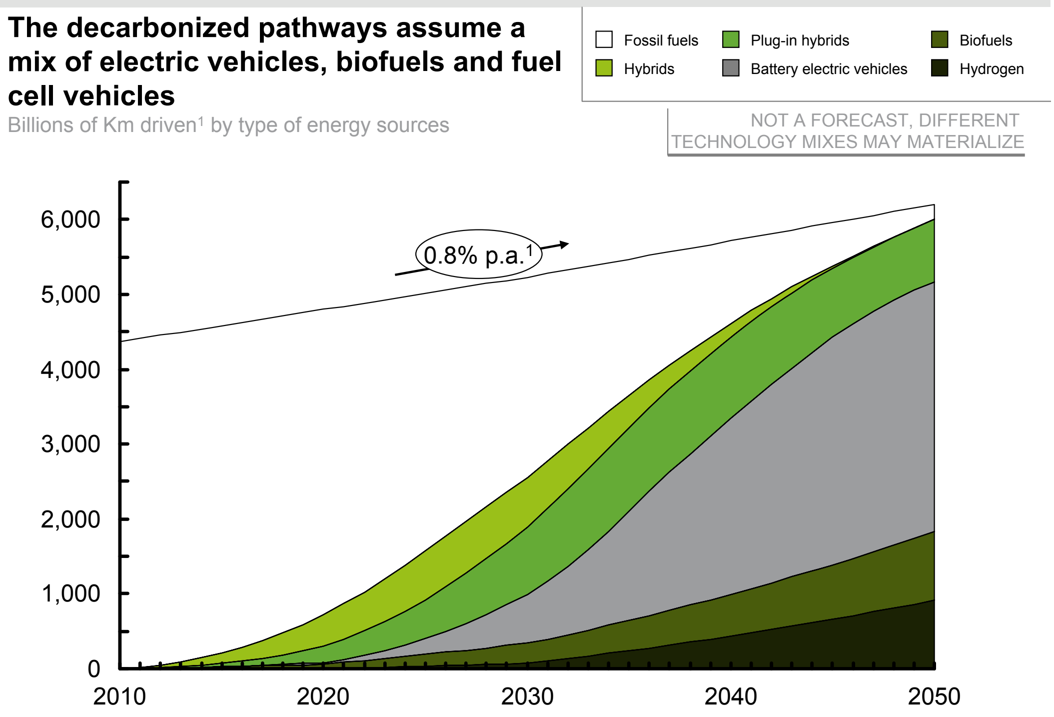
Transport sector – extensive electrification and some biofuels The study assumes a mix of electrification, biofuels and hydrogen[31], with 10% of heavy duty vehicles still running on conventional diesel. This shift would reduce emissions by 0.7 $GtCO_2e$ per year. This is not a forecast of what is most likely to happen in the transportation sector, but simply an assumption – other scenarios are clearly possible. As illustrated in Exhibit 7, the electrification begins with hybrid and plug-in-hybrid drive trains on city vehicles (about 20% penetration by 2020), with small penetration of full electric vehicles up to 2020. By 2030 electric vehicles are assumed to penetrate the market significantly. This would increase electricity demand by about 700 TWh in 2050. Air and sea transport can further reduce emissions by 0.1 $GtCO_2e$ per year by switching to biofuels.

Buildings and industry sector – switching to heat pumps or biomass To realize -80% overall emissions, heating, cooling and cooking is shifted from gas to decarbonized power through using heat pumps. Heat pumps draw heat from the air, the ground or from water to heat a building (and reverse the process to cool a building). They are increasingly efficient and assumed to reach average COP[32] levels of about 4 by 2050. About 90% of the remaining demand in buildings (after energy efficiency improvements) is covered by decarbonized electricity. Where the building density is high, district heating with heat pumps is assumed, such as those

EXHIBIT 7

The decarbonized pathways assume a mix of electric vehicles, biofuels and fuel cell vehicles

Billions of Km driven[1] by type of energy sources



1 Kilometers for heavy trucks normalized with a factor 4 higher fuel consumption per km

31. Hydrogen is assumed to be produced via clean processes such as Integrated Gasification Combined Cycle (IGCC) plants with pre-combustion CCS; Steam Methane Reforming (SMR); or electrolysis.
32. Coefficient of Performance. A COP of 4 effectively means that the heat pump is usefully drawing 4 kWh from the heat source for every kWh of electricity used.

already operating in Stockholm. Alternatives are biomass or biogas fired CHP or district heating plants, or biogas fired boilers in homes. Similarly, 10% of the residual combustion emissions in industry (after energy efficiency improvements) is assumed to be abated with heat pumps.

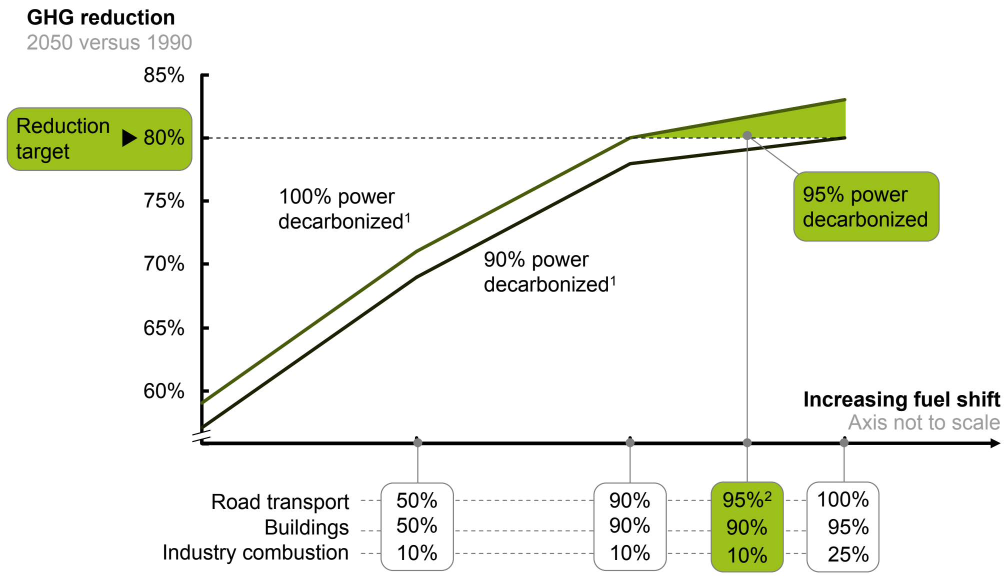
Currently about 7% of heating in Europe is done by electric heating, which requires about 175 TWh per year. This heating is overwhelmingly resistive electric heating, which is up to 4 times less efficient than heat pumps. Shifting 90% of the building heating and cooling demand to heat pump would require 500 TWh per year power demand. This demand is concentrated largely in the winter months. The demand load curve has been adjusted for this, resulting in an increase in peak demand by about 10 to 15%[33], and requiring an additional 80 GW of peak generating capacity assuming 15% intra-day thermal storage in each building. As the capabilities and applicability of heat pumps become clearer with time, more analysis will be required to detail the implications on system security requirements.

With an increase in electricity peak demand, higher gas flows are required to power the gas-fired OCGT backup plants. As gas is no longer being used for heating buildings and is used to a lesser extent than today for mid-merit power generation, much of the existing gas transportation and storage infrastructure will be available. An initial estimate suggests these effects will offset each other.

Alternative solutions exist to decarbonizing the heating sector:

EXHIBIT 8

The power sector needs to be decarbonized between 90 and 100%



1 Decarbonization of power relative to baseline with carbon intensity of 250 tCO_2/TWh, 90% reduction would reduce this to 25 tCO_2/TWh
2 Assumptions: For light- and medium-duty vehicles – 100% electrification (partially plug-in hybrids), for heavy-duty vehicles use of 45% biofuels, 45% hydrogen fuel cells, for air and sea transport use of 30% biofuels, 70% fossil fuels (after 40% efficiency improvement)

33. A range of analysis has been carried out to assess the net effect of the assumed efficiency measures and the effect of moving building heating and EV to electricity. A top-down analysis was undertaken that allocated the expected new heat load over the winter period while also seasonally allocating the energy efficiency effects. This analysis suggested an increase of peak demand of around of 5% compared to historic seasonal demand profiles. A bottom up analysis was carried out utilizing UK data adjusted for very cold -25 degree Celsius temperatures. This analysis demonstrated two things a) that it was possible with a relatively small heat storage device and effective insulation to avoid any substantial increase in electricity demand for a cold spell and b) the overall increase in peak over historic profiles was in the range of 5 -27% depending on the mix of heat pump technologies assumed alongside the penetration of EV. The analysis therefore assumes an increase in 10 to 15% of the peak power demand.

- To supplement more limited electrification, the existing gas network and house boilers could be kept in place and to allow for heating during the coldest days of the year only.
- Houses in climates with the coldest winters can be heated by alternative fuels, like biogas or district heating on biomass, biogas or industrial waste heat.

The power sector is assumed to decarbonize by at least 95% Not only does the power sector reduce its own emissions, it also accommodates the fuel shift from other sectors in order to make the 80% reduction target reachable. As Exhibit 8 highlights, the exact degree to which the power sector must decarbonize depends on the level of decarbonization of the other sectors: the higher the fuel shift of transport, buildings and industry, the less power needs to decarbonize. However, a reduction of less than 95% would imply overly aggressive assumptions on other sectors, such as 100% decarbonization of all transport including HDVs. A reduction of less than 90% in the power sector would make the 80% target effectively unreachable. Decarbonization of the power sector is explored in depth in Chapter 5.

4.3 SIZING OF THE CHALLENGE ACROSS ALL SECTORS

Altogether, the challenge is significant. Reaching the 80% reduction target requires stretched targets across all sectors:

- The baseline itself already assumes that significant energy efficiency improvements are being achieved (1% to 2% p.a.).

- Each sector has to go beyond these improvements to reach the maximum reductions estimated from the implementation of all measures identified in the McKinsey Global GHG Abatement Cost Curve.
- Further penetration of certain measures beyond those in the McKinsey Global GHG Abatement Cost Curve are required between 2030 and 2050 in the forestry, transport and buildings sectors, and further CCS deployment is needed in industry.
- The power sector has to be decarbonized by at least 95%.

- The fuel shift to electrification, biomass, and/or hydrogen has to be implemented to the extent feasible by 2050 in all energy demand sectors: transport, industry and buildings.

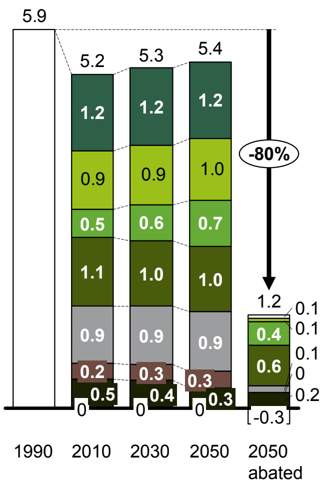
Exhibit 9 (see next page) highlights a plausible combination of abatement levels across sectors that achieves the stipulated 80% target for EU-27 emissions by 2050

EXHIBIT 9

80% decarbonization overall means nearly full decarbonization in power, road transport and buildings

$GtCO_2e$ per year

EU-27 total GHG emissions



Sector	Total abatement	Abatement within sector[1,2]	Abatement from fuel shift
Power	95% to 100%	> 95%	
Road transport	95%	20%	75% (electric vehicles, biofuels and fuel cells)
Air & Sea transport	50%	30%	20% (biofuels)
Industry	40%	35% (efficiency, CCS[3])	5% (heat pumps)
Buildings	95%	45% (efficiency)	50% (heat pumps)
Waste	100%	100%	
Agriculture	20%	20%	
Forestry	-0.25 GtCO2e	Carbon sinks	

1 Abatement estimates within sector up to 2030 based on the McKinsey Global GHG Abatement Cost Curve
2 Large efficiency improvements are already included in the baseline based on the IEA WEO 2009 (up to 2030), especially for industry
3 CCS applied to 50% of large industry (cement, chemistry, iron and steel, petroleum and gas); not applied to other smaller industries
SOURCE: McKinsey Global GHG Abatement Cost Curve; IEA WEO 2009; US EPA; EEA; Team analysis

CHAPTER 5
DECARBONIZING POWER: TECHNICAL RESULTS

This chapter demonstrates potential pathways to decarbonize the European power sector by 2050. Power sector decarbonization can be technically achieved in all of the pathways modeled, each delivering the current standard of system reliability while differing in terms of generation mix, using only current and late-stage development technologies. In each pathway, extensive energy efficiency measures are essential, as is the expansion of the electricity transmission grid. Greater transmission interconnection between regionally dispersed generation sources and demand centers enables closer matching of demand and supply across Europe, with associated system operation benefits in terms of complexity and cost. Demand Response (DR) has been demonstrated to be an increasingly important means of balancing the grid and avoiding curtailment of low-carbon, low-marginal-cost resources, particularly renewable generation. Sensitivity analysis shows that even potential alternatives in some of the input assumptions do not fundamentally change the overall outcomes.

5.1 OBJECTIVE AND PATHWAY DESCRIPTION

As highlighted in chapter 4, the power sector is one of the cornerstones of reaching the 80% GHG reduction target by 2050 and will need to decarbonize by at least 95% if this target is to be met. Therefore this work explicitly models the power sector with the objective of assessing the technical feasibility of reducing power sector GHG emissions by at least 95% with no degradation in reliability. To make the results more robust, the work was constrained to using technologies that exist or are in late stage development, with reasonable assumptions about the opportunities for improvement in those technologies.

The study assesses three main decarbonization pathways. These pathways are designed to be technology agnostic, use multiple technologies, and to reflect a wide range of technically and economically plausible inputs. They differ in the respective shares of electricity that are produced by the three classes of low/zero carbon generation technologies: fossil fuels with CCS, nuclear, and Renewable Energy Sources (RES). The proportion of electricity supplied from RES in 2050 varies between 40% and 80% depending on the pathway. For each pathway, fossil fuel plants (with CCS) and nuclear generation supply the remainder in equal proportions[34] to remain neutral with respect to technology selection and to avoid increasing the number of pathways analyzed. Additionally a scenario with 100% RES is evaluated primarily to test the implications on grid stability and service reliability, and is detailed in chapter 7 on *Further opportunities*.

In the decarbonized pathways, new generation capacity either meets additional demand or replaces a plant that has reached the end of its economic lifetime (e.g., 30 years for gas-fired CCGT; 40 years for coal). Hence, while the power pathways rely on current generation assets being retired at the end of their assumed lifetimes, it does not require the earlier retirement of plants (i.e., stranded equity value) to reach 95% decarbonization by 2050. Indeed, most existing plants will retire before 2040. Lifetime extensions of these high carbon assets would delay the penetration of decarbonized generation capacity, impacting the ramp up of future capital requirements.

5.2 POWER DEMAND AND SUPPLY ASSUMPTIONS

5.2.1 Power demand

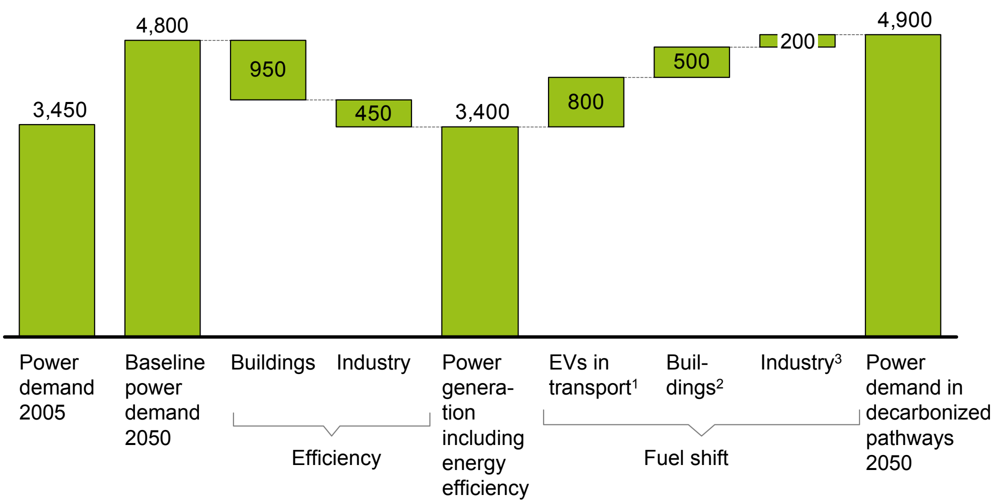
As described in chapter 3, the 2050 baseline power

34. With an even split between coal and gas with CCS, again meant to increase the robustness of the study

EXHIBIT 10

Power demand will go down due to higher efficiency and up due to additional demand from transport and building heating

EU-27, Norway and Switzerland power demand, TWh per year



1 Electrification of 100% LDVs and MDVs (partially plug-in hybrids); HDVs remain emitting ~10% while switching largely to biofuel or hydrogen fuel cells
2 90% of remaining primary energy demand converted to electricity (heating/cooling from heat pumps, assumed 4 times as efficient as primary fuel)
3 10% of remaining primary energy demand for combustion converted to electricity (heating from heat pumps, assumed 2.5 times as efficient as primary fuel)

demand has been extrapolated from the IEA WEO 2009. Power demand in the decarbonized pathways is derived from the baseline and is the result of: (i) a reduction in demand through adoption of more aggressive energy efficiency measures in line with overall buildings and industry abatement potential[35]; and (ii) higher demand due to electrification in other sectors, primarily in road transport (light duty and medium duty vehicles), building heat (heat pumps), and to a lesser extent, electrification of process heat in industry. This is described in Exhibit 10 and is in line with chapter 4 developments.

By coincidence, the 2050 power demand is similar in both the baseline and the decarbonized pathways, at 4,800-4,900 TWh for the EU-27 plus Norway and Switzerland. This is due to the fact that the additional energy efficiency assumed in the pathways offsets higher power demand from fuel shifts to power. The increase in electricity demand over time is based on the following roll-out assumptions: energy efficiency measures are assumed to be implemented linearly up to 2050; the shift in road transport to electric vehicles accelerates after 2020 as described in chapter 4, resulting in an S-curve for the related increase in electricity demand; the roll out of heat pumps is assumed to be linear up to 2050 for the shift in both buildings and industry. As shown in Exhibit 11, all of this results in a build up in electricity demand to 2050 similar in both the baseline and the decarbonized pathways.

5.2.2 Power supply

Power mix by technology

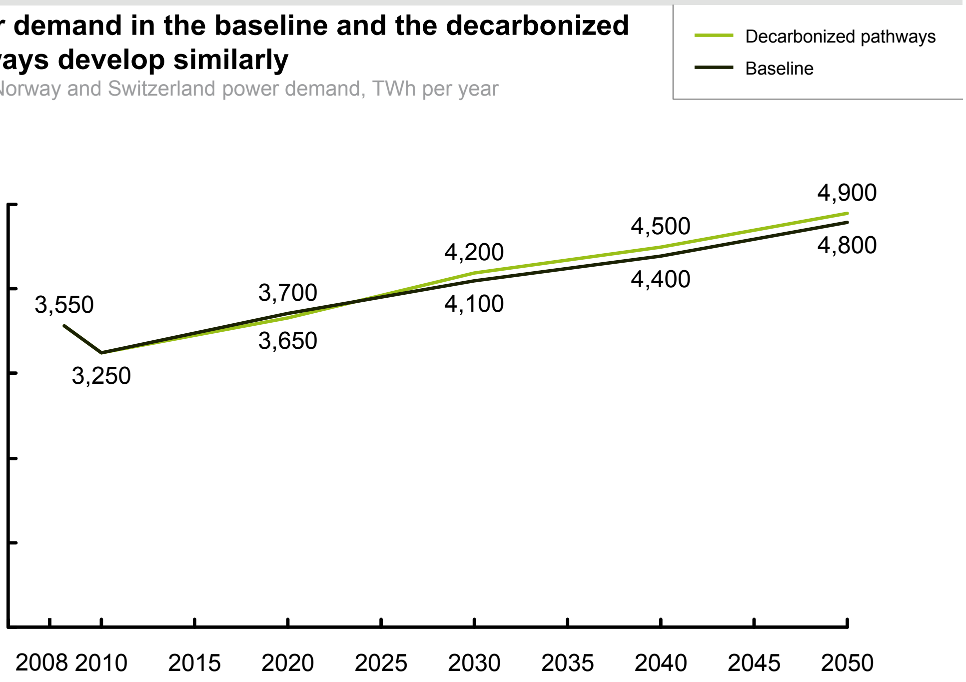
As described previously, this work is a "back-casting" exercise, working backwards from postulated 2050 outcomes to the current timeframe. One of the first

35. Beyond the energy efficiency measures included in the IEA WEO 2009 baseline

EXHIBIT 11

Power demand in the baseline and the decarbonized pathways develop similarly

EU-27, Norway and Switzerland power demand, TWh per year



conclusions to emerge is the need to decarbonize the power sector virtually completely by 2050; the three main pathways postulated to accomplish this are outlined in below. In this section the supply resources in each pathway will be broken down in more detail. This is based on the following criteria:

- The minimum capacity for each renewable technology is set by existing capacities, while the maximum potential capacity is derived from workshops with industry experts.

- The baseline is taken as starting point and reaches a mix in 2050 of 34% RES (maximum hydro potential, strong rollout of biomass), 49% from fossil without CCS and 17% from nuclear.

- A wide set of technologies is applied instead of relying on a few technologies.[36] This means, for instance, that a similar share of wind and solar is applied.

- The overall mix of technologies in each pathway is thus not optimized around a single parameter such as least cost, but is rather an attempt to set out a range of plausible outcomes for comparison purposes, reflecting the practically exploitable potential of renewable resources in Europe, as well as reflecting a range of possible outcomes from choices that EU and member state policymakers could make over 40 years.

- The allocation of supply options geographically is likewise not intended to be an optimized allocation, nor is it an exhaustive projection of all resources that may be deployed in each region; it is rather an attempt at a plausible allocation, based on a simple algorithm, reflecting the diverse supply options given variations in each region's indigenous resources.

36. While the mix of technologies is assumed to be broad, it is not intended to be exhaustive; some technologies, such as tidal power, could well be part of local resource mixes, but the analysis focused on the options with the potential to be material at an EU-27 scale.

EXHIBIT 12

A balanced mix of production technologies has been assumed

In percentage of production

	Coal	Coal CCS	Coal CCS retrofit [1]	Gas	Gas CCS	Gas CCS retrofit	Nuclear	Wind On-shore	Wind Off-shore	Solar PV	Solar CSP	Biomass	Geothermal	Large Hydro
80% RES 10% CCS 10% nuclear	0	3	2	0	5	0	10	15	15	19	5	12	2	12
60% RES 20% CCS 20% nuclear	0	7	3	0	10	0	20	11	10	12	5	8	2	12
40% RES 30% CCS 30% nuclear	0	7	3	0	10	0	20	11	10	12	5	8	2	12
Baseline: 34% RES 49% coal/gas 17% nuclear	21	0	0	28	0	0	17	9	2	1	1	8	1	12

1 Only on "CCS ready" plants

See Exhibit 12 for the share in production of each technology in each of the three main pathways. The 2050 production shares have been back-casted to 2010 using a deliberately simple approach, following a roughly linear build-up. Implied capacity requirements for solar PV, Wind and backup plants are included in Exhibit 13. These should not be used as a short term capacity forecast. The capacity estimates for individual technologies are lower in some pathways than what the respective industries are planning for, e.g., the wind industry expects a 25% higher wind capacity build out in 2020 than what is assumed for in the 60% RES pathway, and 40% higher than assumed in the 40% pathway.

Separately, in chapter 7 on *Further opportunities*, a 100% RES scenario is being described and evaluated primarily to test its system reliability. In this scenario two additional assumptions are made: power can be generated in and imported from North Africa (covering 15% of 2050 European demand); and a breakthrough technology (enhanced geothermal systems (EGS)) is used (covering 5% of 2050 European demand, all produced in Europe).

Fuel cost assumptions in the decarbonized pathways

The costs of fuel are assumed to be the same in the decarbonized pathways as in the baseline. Second-order effects from the reduction of coal, oil and gas demand in the decarbonized pathways have not been taken into account, due to uncertainty about the nature of such second-order effects and the complexity of modeling various possibilities. Indeed, with such a reduction in demand, prices would likely be lower in the decarbonized pathways, making them look even more attractive economically compared to the baseline. Other plausible scenarios, however, could produce different outcomes. Therefore fuel prices have been kept constant across all scenarios modeled.

5.2.3 Power system assumptions

EXHIBIT 13

Significant capacities are required in solar, wind and back-up plants

GW installed in 2050

	Fossil fuels	Solar PV	Wind onshore	Wind offshore	Other[1]	Back-up plants
80% RES 10% CCS 10% nuclear	80	815	245	190	420	270
60% RES 20% CCS 20% nuclear	155	555	165	130	455	240
40% RES 30% CCS 30% nuclear	240	195	140	25	490	190
Baseline: 34% RES 49% coal/gas 17% nuclear	410	35	140	25	380	120

1 Includes nuclear, hydro, biomass, geothermal, solar CSP

Model methodology for the transmission system

The applied power system analysis framework[37] minimizes the total system costs, maintains the required level of system reliability and respects operating constraints. Costs are driven by additional generating capacity, additional inter-regional transmission network capacity, and the annual electricity production cost. This cost minimization process considers the tradeoffs between the cost of additional generating capacity, additional transmission infrastructure, renewable energy curtailment and the transmission constraint cost incurred for network congestion management.
The modeling follows two steps:

- First, the required additional generation and inter-regional transmission capacity is determined by minimizing the infrastructure investment costs and hourly system operation costs across the time horizon of a year, while delivering the historical levels of security of supply. The impact of extreme conditions of low output of renewable generation and extreme peak demands on both generation and network capacity requirements are examined. The potential benefits of demand response and storage reducing the need for additional generating capacity and inter-regional transmission are evaluated.

- Second, the operation of the system is optimized throughout the year. Using a stochastic framework that captures multiple possible realizations of renewable generation outputs, the generation daily production costs are minimized while allocating adequate resources needed for the management of the fluctuations of intermittent renewable sources. A range of dynamic technical constraints and cost characteristics of generating

37. Developed by Imperial College London

plant are considered (such as stable generation levels, ramp rates, minimum up/down times, start up, no load costs etc) together with energy storage reservoir capacities, efficiency losses and demand response that may be available. While maintaining the required levels of short and long term reserves, based on the existing UCTE rules, the model takes into account the benefits of diversity in renewable generation production and diversity in demand across different regions enabled by the inter-regional transmission network.

A conservative approach has been followed throughout the grid integration modeling. This is manifested through a range of prudent modeling assumptions adopted, such as limited flexibility of nuclear generation; higher levels of short term forecasting errors of renewable generation (based on persistence forecasting techniques); the fact that load curtailments are not considered as an option for the provision of backup; exclusion of frequency responsive loads (e.g., refrigeration) in the provision of frequency regulation services; and incorporating the effects of extremely low outside temperatures in winter peak demands.

A more in-depth description of the methodology and models is given in the online Appendices.

In practical terms the model determines what new transmission capacity, new backup generation or operating costs (mostly fuel costs) will be required in order to optimize the overall cost of the transmission system, while maintaining system security and ensuring an hour by hour balance. The model adds new generation or transmission capacity to the original pathway generation to provide adequate supply capacity in each region to meet the highest peak demand across the year.

The transmission system model divides the EU-27 countries plus Norway and Switzerland into nine regions, thus reducing complexity. The nine regions are sufficient to establish the high-level incremental needs for exchange of energy in 2050. Today's congestion within existing networks is not considered as the location of generation capacity and demand could change in the next 40 years; and any remaining congestion would also be addressed in the baseline and therefore not lead to incremental costs in the pathways. The balancing calculations and requirements do not significantly depend on the number of regions as they are driven mainly by the number and characteristics of the generation plants. Furthermore, short-term balancing is modeled to be met within each region and therefore doesn't impact the inter-regional transmission requirements.

Each region has a "centre of gravity", which functions as the point from and to which transmission capacity will be required. The scope of the transmission system analysis is focused on *incremental* capacity requirements between the nine regions from each decarbonized pathway relative to the 2050 baseline, i.e., investments common to the baseline and all pathways are shown separately in order to highlight the incremental requirements associated with increasing RES penetrations. The transmission costs calculated include the costs from new and concentrated offshore wind sources to the shore and further to the regional 'centre of gravity'. This modeling does not assess the investment requirements for the distribution network (see the complete note on this topic at the end of this section).

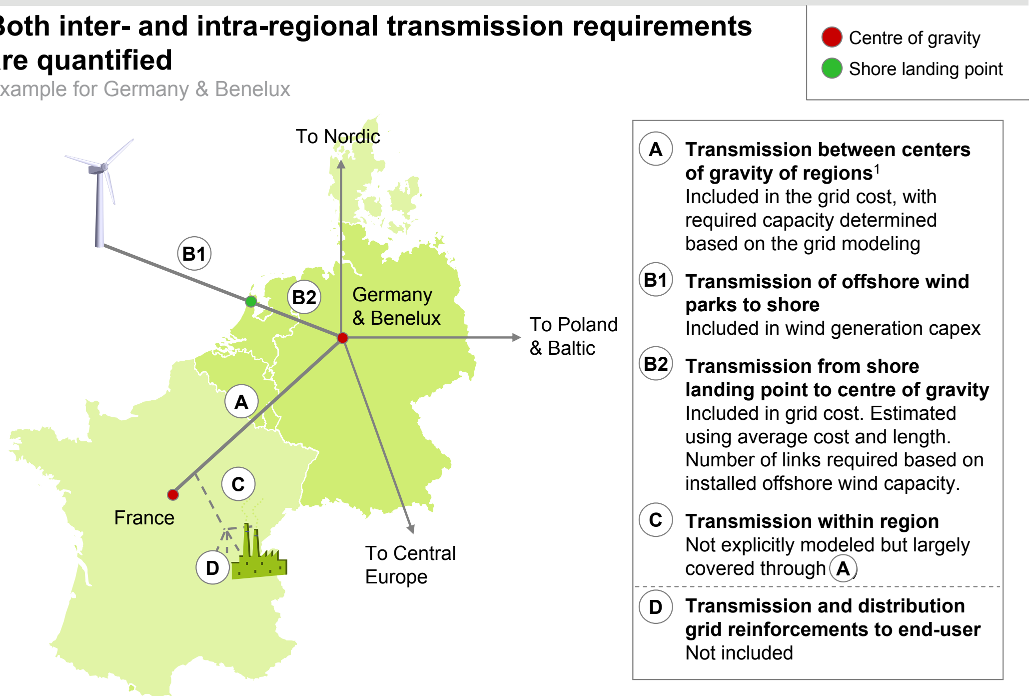
Intra-regional transmission expansion and reinforcement requirements have been addressed by combining the following two elements. Firstly, for the inter-regional transmission requirements between centers-of-gravity, the costs of additional transmission infrastructure have been modeled across each region, which provides a proxy for the many, smaller, reinforcements typically needed within each region. Secondly, the transmission capacity for energy transport from offshore wind parks has assumed sufficient incremental intra-regional transmission investment to accommodate delivery of the full wind park capacity to the notional centre of gravity. These approaches result in significant intra- regional transmission investments and thus both approaches serve as proxies for the diverse reinforcements requirements of regional TSO grids. Exhibit 14 illustrates these various elements.

More detailed transmission studies will be needed in the future to support more granular decision-making. These studies would ideally be undertaken with

EXHIBIT 14

Both inter- and intra-regional transmission requirements are quantified

Example for Germany & Benelux



1 This assumes a firm capacity capability from centre of gravity to centre of gravity that would allow for the dispersion of power along the way implicitly covering intra-regional reinforcements

ENTSO-E coordination as part of the SET Plan's European Electricity Grid Initiative.

Electricity distribution networks will also need to evolve to accommodate potentially significant changes in aggregate demand and associated load profiles. Such changes will arise from requirements to integrate decentralized generation sources, EV charging infrastructure (potentially including provisions for the back-delivery of energy from EV's to the grid[38]), and high-efficiency electric heating systems and will impact the distribution grid. "Smart" technologies and systems will be key enablers to proactively manage power flows and minimize increases in network capacity required.

In this project, the physical requirements and the costs for changing the distribution network have not been modeled. This is due to (i) the uncertainty about physical requirements and costs to sustain the baseline and the decarbonized pathways; (ii) the large uncertainty about the "baseline" development of the distribution grid and therefore the *additional* effort required specifically in the decarbonized pathways, and (iii) the complexity of modeling a highly granular network 40 years into the future.

Therefore, to get a complete picture of all network-related requirements and costs the analyses in this report on transmission must be complemented with similar analyses on distribution. The online Appendices contain a detailed review of a sample study performed by KEMA and Imperial College London utilizing existing data from the United Kingdom.

Transmission system input assumptions

The transmission system is modeled at an hourly resolution (although short term reserve requirements are modeled in more detail at the quarter-hourly level) and uses the following assumptions. Regional

38. It has been conservatively assumed that there is no back-delivery of energy from EVs to grids.

demand curves are derived by splitting the annual demand in each pathway by region, and using historic load profiles created for each region from country specific data. The seasonality of these profiles have been adjusted to reflect the impact on power demand in all decarbonized pathways from energy efficiency measures, increased reliance on electric heating and widespread adoption of EVs. The demand fluctuations on EU level are lower than on regional level, given the variety in regional demand profiles (e.g., time-shift in peak demand between regions).

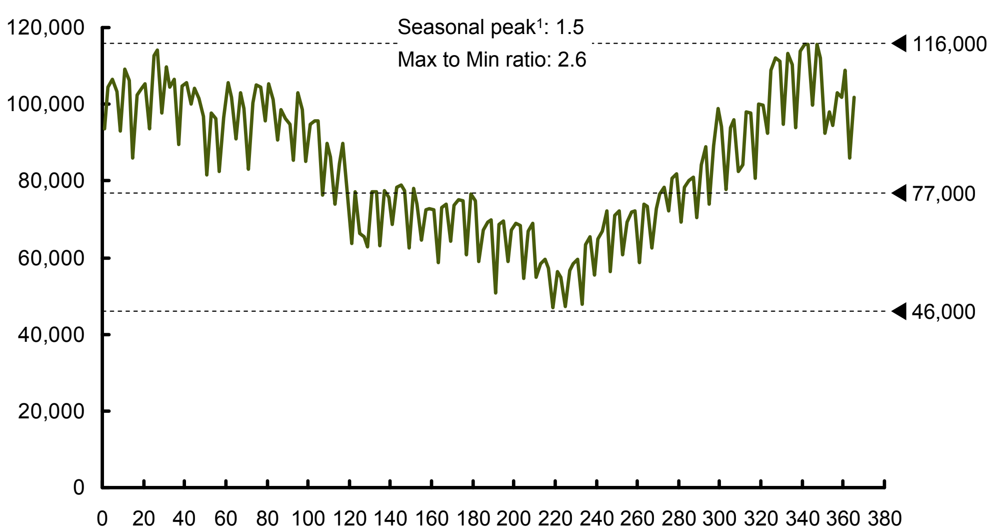
The system has been designed to cope with two additional effects: an increase in the seasonal peak and the effect of a cold spell on the level of the peak demand. The normal seasonal effects lead to an increase in the system peak demand of around 12% across Europe compared to historic profiles, reflecting the increased use of electric heat pumps. This assumes a mix of air and ground source heat pumps and complete implementation of the full range of energy efficiency measures. The effect is muted because the energy efficiency measures also have a seasonal profile and substantially reduce the peak demand in winter. The analysis of the effect of a cold spell considered the potential increase in electricity demand from heat pumps as temperature falls. The analysis concluded that modest capacity increases allow cold temperatures to be met. This assumes that the current level of comfort will remain the standard, that the energy efficiency and insulation measures assumed in the power demand have been carried out, and a storage capacity for hot water covering 15% of daily heat demand is available. The resulting electricity demand curve is shown in Exhibit 15 below for France.

For supply, the model utilizes reference real observed data for solar and wind sources, differentiated by region and adjusted to reflect the installed capacity and technical performance of the renewable technologies. This is used as the forecast scheduled, which is then enriched by stochastic modeling. The

EXHIBIT 15

Load curve for France, adjusted for increased winter peak for heat pumps

2050, GW



1 Seasonal peak defined as winter demand peak divided by summer demand peak

response and reserve requirements for each of the regions are based on UCTE guidelines. Generation technology flexibility characteristics (e.g., the rate of change of output) have been taken from current industry standards (detailed assumptions can be found in the online Appendices). Fossil fuel plants fitted with CCS have been assumed to have the same flexibility as fossil fuel plants without, based on industry consultation. A sensitivity with reduced flexibility has been included in section 5.3.

To ensure a robust system design, a combination of extreme weather events has been taken into account to account for potentially low supply. The system has been designed to cope with a combination of a dry hydro year (a 1:20 event) and a synchronous 50% drop in wind output across multiple locations compared to average (such an event has not happened in the period 2003-2006 for which data is available).

Pathways are modeled both with and without Demand Response (DR). The DR allows a maximum of 20% of the daily energy demand to be moved within the day, i.e. there is no demand reduction. The underlying assumptions for the DR are that the electrification of heat includes local heat storage, and that the EV's charging cycle is managed. No new large scale power storage has been assumed beyond the existing pumped storage hydro capacity, with the exception of some storage associated with CSP (up to six hours). Also the potential re-powering of Norwegian hydro with bigger turbines has not been included.

The costs of transmission expansion (both capex and opex) are based on KEMA data that have also been peer-group tested with TSO organizations. The costs of transmission expansion can be significantly impacted by technology selection (HVAC vs. HVDC) and network architecture (overhead lines vs. underground cables). Rather than being prescriptive regarding any particular technology, KEMA assumed the following expansion characteristics for transmission infrastructure: a mix of 73% AC and 27% DC technology, with 67% reliance on overhead lines and 33% reliance on underground cables for each technology. Further modeling was undertaken regarding the sensitivity of such cost estimations to design choices. More detail on the grid assumptions can be found in the online Appendices.

5.3 TECHNICAL RESULTS

This section illustrates that all pathways can be made sufficiently reliable through the addition of backup generation and/or transmission capacity. Beyond the technical feasibility of the pathways, the scale and the high benefits of the transmission investments, the extent of regional backup generation requirements, and the levels of RES curtailment for each of the pathways are discussed. Chapter 6 will go further describing the impact of these capacity additions on the cost of electricity.

The 6 following key technical results are further detailed in this section:

1. **Generation capacity requirements are larger with higher RES:** Installed generation capacity increases significantly in the decarbonized pathways with increasing wind and solar PV penetration due to their variable output and lower load factors.

2. **Transmission capacity and backup generation requirements are significant in all decarbonized pathways:** incorporating large shares of intermittent renewables into the transmission system is technically feasible but significant increases in transmission capacity are necessary (50 to 170 GW, increasing in line with higher intermittent generation[39]) as well as additional backup generation capacity (10-15% on top of the generation capacity for each pathway). However, through such transmission investments, it is possible to moderate the curtailment of RES output to <3%, even in the 80% RES pathway. In the baseline, additional inter-regional transmission capacity is limited to 2 GW, which reflects the benefits of planning and operating the EU power

39. Wind and solar PV represent 15%, 33% and 49% of production in the 40%, 60% and 80% RES respectively

system in an integrated fashion as assumed to be the case by 2050 in this study.

3. **Inter-regional demand and supply sharing is key:** This additional transmission is particularly effective as it smoothes the demand and supply profiles, and it allows the sharing of geographically and technologically diverse energy resources across Europe. Without such inter-regional supply sharing, it becomes far more challenging for individual regions to achieve the decarbonization and RES penetration targets as additional generation investments are required with higher levels of curtailment.

4. **Impact of "Demand Response" is significant:** Making certain types of power demand responsive to variations in the supply (production) of electricity is an effective means of reducing transmission investment and backup generation requirements. In the higher RES pathways, such demand response interactions can reduce such investments by 20 to 30%.

5. **Sensitivities highlight robust results:** The sensitivities performed show that the technical feasibility is robust to changes in the key assumptions.

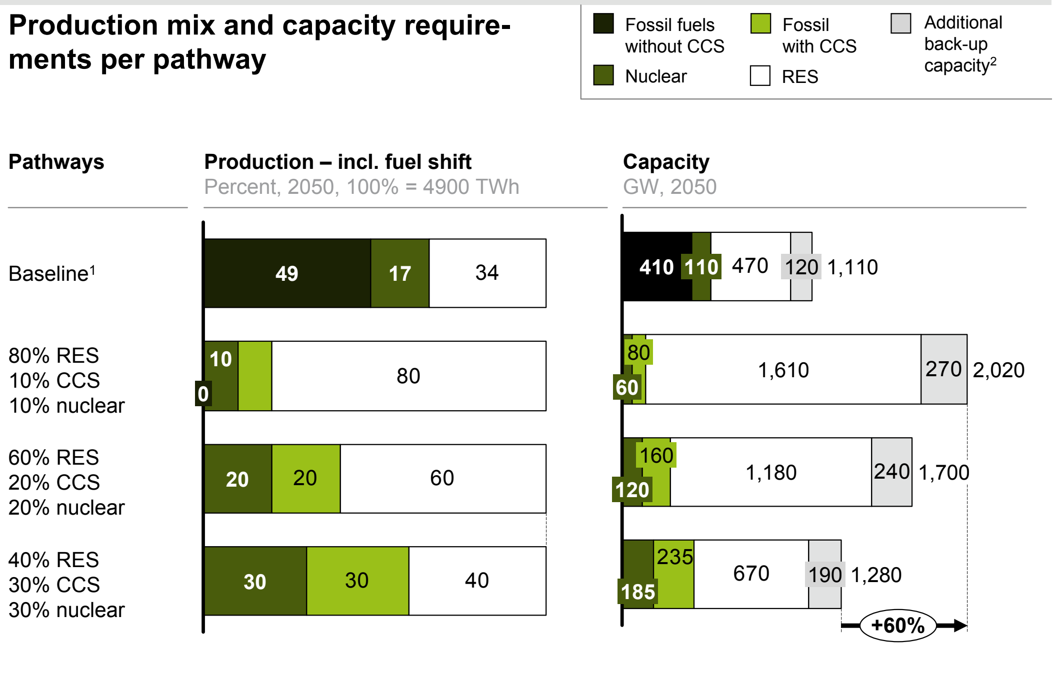
6. **Capacity build rates are high but technically feasible:** both for generation and grid the increase in yearly capacity output by the industry is feasible and not unprecedented. However, short-term implementation delays will only serve to exacerbate the scale of the implementation challenge.

5.3.1 Generation capacity requirements are larger with higher RES

The generation capacity needed to meet demand increases with increasing RES penetration. This is due to the fact that the increased RES penetration is

EXHIBIT 16

Production mix and capacity requirements per pathway



1 Supply of 4800 TWh, technology split by PRIMES, forecast updated with IEA WEO 2009 and Oxford economics
2 Additional back-up capacity to meet peak demand. Assumed to be OCGT in the costing, but could be any equivalent. 20% DR case shown.

predominantly driven by increased reliance on wind energy and solar PV, which have lower load factors compared with geothermal, biomass, hydroelectric, solar CSP, fossil fuel CCS and nuclear plants. That is, wind and solar PV tend to operate at part load relative to full rated capacity for much of the year. For example, an offshore wind turbine typically provides around 40% of the energy it would provide if it were always running at full rated capacity. As a result, the 80% RES pathway requires 60% more installed capacity than the 40% pathway. The capacity required per technology in each pathway are illustrated in Exhibit 16.

The higher capacity needs will come with higher capital investments. Yet, as shown in more detail in chapter 6, the increased capital costs for the high-RES pathways are mostly offset by lower operating costs of these technologies, due to substantially lower primary energy costs, e.g., wind and sun.

5.3.2 Transmission capacity and generation backup requirements are significant in all decarbonized pathways

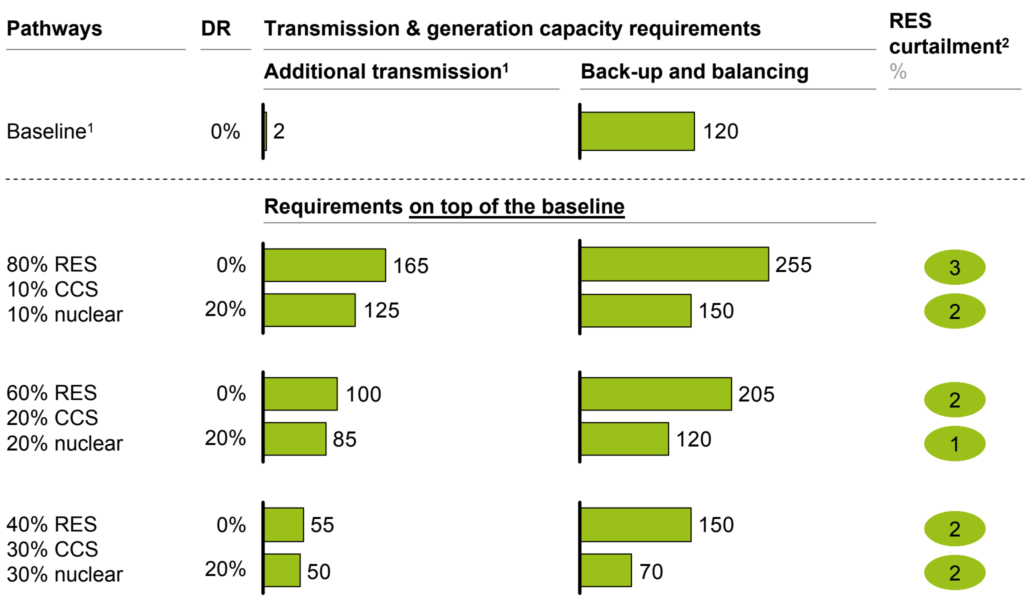
As shown in Exhibit 17, there are significant incremental requirements for transmission capacity and backup generating capacity in all of the decarbonized pathways, and they increase with increased penetration of intermittent renewable energy sources. In comparison, the baseline requires 2 GW of additional transmission capacity and 120 GW of additional backup and balancing capacity.

There is a trade-off between transmission capacity and backup capacity. Backup capacity can avoid the need for transmission lines used only a few hours a year to shift power from one region to the other. On the other hand, sufficient transmission capacity will avoid the need for backup generation by sharing surplus generation resources between regions. The

EXHIBIT 17

Transmission flows and back-up generation capacity requirements

2050, GW



1 Requirements by 2050 additional to existing lines
2 In percentage of total renewable energy production

inter-regional transmission capacities presented in this chapter have been optimized to avoid excessive network investment or correspondingly low asset utilization. Overall, capacity utilization figures of 60-90% have been forecast. Such utilization figures mean the capacity is used day and night and across the seasons. This is different to today, where inter-regional transmission capacity is utilized mostly to meet peak demands within regions.

Chapter 7 on *Further opportunities* will describe the implications on transmission and backup plants for the 100% RES scenario as well as the estimate of the likely impact on the LCoE.

Exhibit 18 illustrates effective transfer capacity requirements for the 60% RES pathway, with 20% demand response. The transmission capacities shown are indicative of the needs if Europe decides to realize the 80% reduction ambition on a European scale. In such a scenario, renewable capacity would be installed where resources are most abundant even if production would exceed local demand, because additional transmission capacity would facilitate transfer of surpluses to other demand centers. The most noticeable case for this is Iberia, where favorable onshore wind and solar conditions could result in significant export potential for RES capacity. The resulting need for transmission capacity to France (32GW in the 60% pathway) is therefore also large. However, the composite cost for the grid assumes a significant amount of underground/sub-marine HVDC for the grid expansion, which could be used to minimize the challenge by, for instance, running cable undersea through the Bay of Biscay. It is also clear that more wind and solar could be built outside Iberia lessening the need for transmission capacity from Spain to France. Finally, while adding capacity in this region has historically been limited, it should be seen in the light of the overall context of this work: a European energy system that will be fundamentally different from that of today in which overcoming this challenge will be only one of the large obstacles for decarbonization.

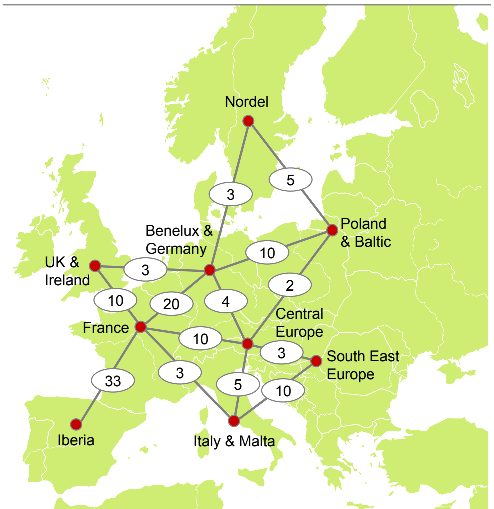
EXHIBIT 18

Grid expansion requirement example: threefold increase required for the 60% RES pathway

Centre of gravity

60% RES, 20% DR

Total net transfer capacity requirements
GW (existing + additional)



Interconnection	**Capacity** additional + (existing), GW	**Annual utilization** %
▪ UK&Ireland-France	8 + (2)	75
▪ UK&Ireland-Nordel	0 + (0)	0
▪ UK&Ireland-Benelux & Germany	3 + (0)	83
▪ France-Iberia	32 + (1)	83
▪ France-Benelux & Germany	14 + (6)	78
▪ France-Central-Europe	7 + (3)	93
▪ France-Italy &Malta	0 + (3)	92
▪ Nordel-Benelux & Germany	0 + (3)	75
▪ Nordel-Poland & Baltic	4 + (1)	60
▪ Benelux & Germany-Central-EU	0 + (4)	74
▪ Benelux & Germany-Poland & Baltic	9 + (1)	81
▪ Central-Europe-Poland & Baltic	0 + (2)	77
▪ Central-South East EU	1 + (2)	80
▪ Central-Europe-Italy	0 + (5)	58
▪ South East EU-Italy	9 + (1)	79
Total	**87 + (34)**	

The effect of a lower transmission capacity build-up is shown as a sensitivity in chapter 5.3.5 and would lead to a significant increase in renewable curtailment or require greater investment in storage facilities. For a full overview of the results for all pathways refer to the online Appendices. Later in this chapter 5 a comparison is given between historical transmission build rates and the required building rates in order to realize the capacities given in Exhibit 18 on the right. It shows that, at the European level, only a modest increase in the building rate of the last 10 years would be sufficient to reach the total capacity suggested for the 60% pathway in 2050. However, as highlighted above, the situation at the regional level can be more challenging.

There are significant backup generation requirements in all pathways, with low load factors ranging from 5% to 1%. In principle a mix of storage and generation capacity could provide this need, but no additional large-scale storage has been assumed in this study. Beyond large hydro, which has been nearly fully exploited in Europe, storage options do not yet exist that can cost-effectively shift energy from one season to another. This study has used Open Cycle Gas Turbine (OCGT) technology as a proxy for such a low capital cost and highly flexible source of backup generation capacity.

If OCGTs were to be used with fossil fuels (e.g., natural gas or liquid fuels), CO_2 emissions cannot be ignored as they would be reaching 1 to 6% of total power sector emissions before abatement (for the 100% RES scenario emissions from gas-fired backup plants would be 7-15% of pre-abatement emissions). These emissions can be avoided either by burning green fuels (e.g., bio-gas), CO_2-free hydrogen or by alternative generation technologies that use biomass as a fuel.

In case of purely natural gas driven backup capacity significant gas delivery infrastructure would be needed to deliver the gas for those hours the OCGTs would be running. The current total volume of high-flexibility storage facilities in Europe would be roughly sufficient, assuming half the currently planned additional storage facilities are realized. Of course, on a more granular level the possibility of local surpluses and deficiencies cannot be ignored.

Plausible alternatives to new OCGTs would be to build additional fossil fuel with CCS generation (reducing the average load factor of that technology) or extend the lifetime of gas plants that are currently assumed to be retired at the end of their lifetime (30 years). The use of these plants would reduce the need for new backup plant by 10% to 15%, depending on the pathway. However, technical limitations on warming-up time might prevent CCGT plants with CCS to be used as pure backup plants. It is likely that these will need to be stripped of their steam-cycle and CCS elements to reduce the time required for start up.

5.3.3 Inter-regional demand and supply sharing is key

Transmission capacity between regions is effective at lowering the need for excessive backup generation capacity and balancing costs, allowing the sharing of system resources and reserves.

The increased inter-regional connectivity creates benefits in sharing of reserves. Longer-term reserve capacity that needs to be on-line within four hours is assumed able to be shareable between regions, whereas sufficient fast (spinning) reserve is not shared and is provided entirely from resources within each region. Sharing of resources and reserves brings down the backup generation capacity required as reserve and the costs of balancing services by 35-40%, depending on the pathway, as illustrated in Exhibit 19.

In addition to allowing cross-regional sharing of reserves, transmission reduces the impact of demand variability as well as supply variability over the transmission system, and it leverages the negative seasonal correlation between solar and wind production. Differences in daily and seasonal patterns of demand among regions result in lower aggregated demand variability as illustrated in Exhibit 20. On a daily and seasonal basis, the ratio of peak demand to minimum demand is reduced.

The same mechanism is at work on the supply side. For example, wind output can be highly volatile on a local level, but empirical data for Europe show that volatility dissipates substantially

EXHIBIT 19

Reserve sharing across EU-27 reduces total reserve requirements by ~40%

Maximal reserve requirements[1], GW

Region	Baseline	80% RES	60% RES	40% RES
UK & Ireland	8	42	28	15
France	2	31	21	9
Iberia	7	40	27	10
Nordic	3	20	15	10
Benelux & Germany	13	44	28	10
Central-Europe	2	29	20	8
Poland & Baltic	2	18	12	5
South East Europe	2	18	12	4
Italy & Malta	2	40	27	10
Total EU27	42	281	191	80
Benefit of reserve sharing	20	98	66	32
Total with reserve sharing between regions	22	183	125	48
	-47%	-35%	-35%	-40%

1 Reserve refers to reserve required at four hour ahead of real-time. This is required to manage the larger changes in generation (due to plant outages and expected uncertainty in intermittent output) expected over that four hour period that could require starting additional (or switching off) generation

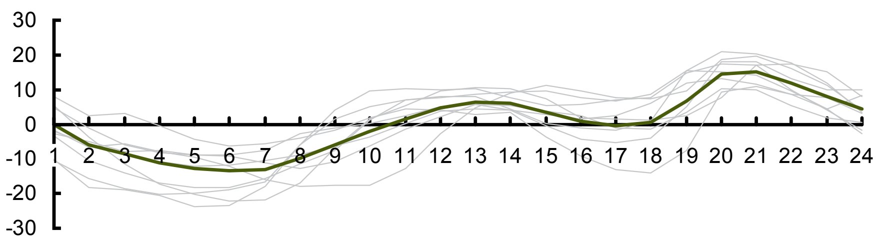
EXHIBIT 20

Increased transmission cancels out both daily and seasonal fluctuations

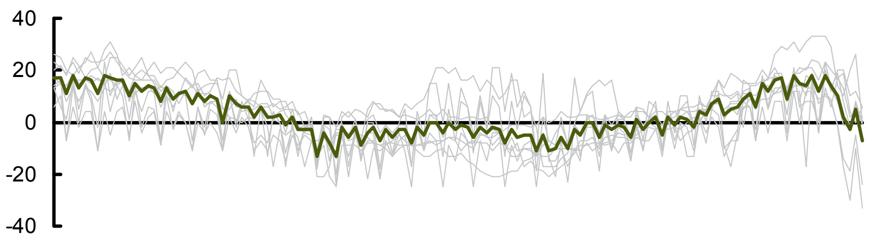
Percent

Individual regions
Total EU-27

Example: Regional demand variation from average per hour during one day



Regional demand variation from average over the year



when measured across resource areas that are sufficiently dispersed. Data aggregated from six widely dispersed European wind locations over 4 years (2003-2006) showed that aggregate wind lulls of up to 25% occurred at a rate of only 4 days per year.[40] Therefore, need for backup generation and balancing is significantly lower if multiple regions with sufficiently non-correlated resource profiles are more effectively interconnected.

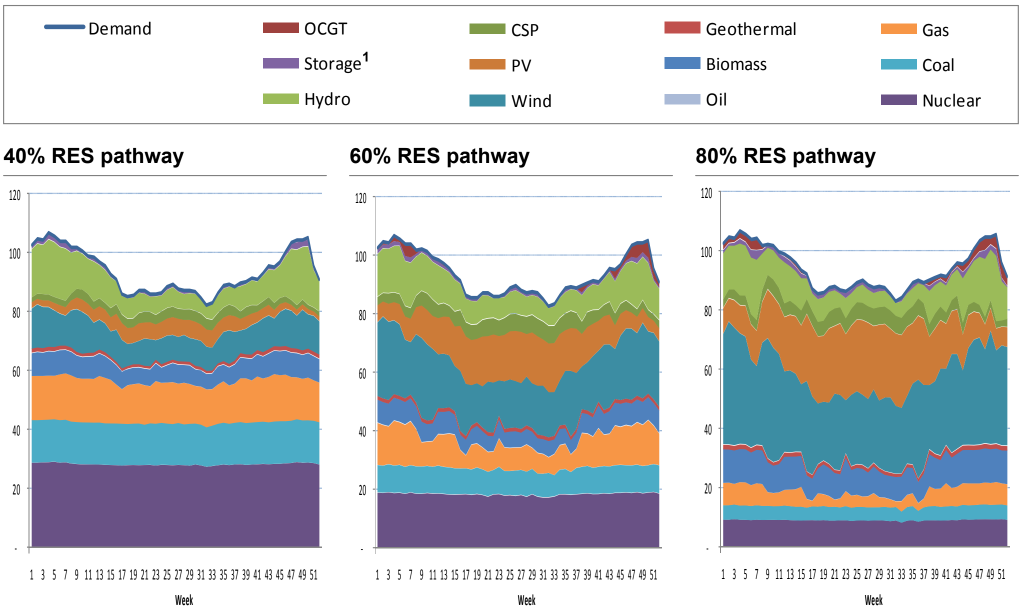
Expanded inter-regional power transfer capacity (along with the assumed use of a mix of RES technologies) also enables the exploitation of counter-cyclicality among renewable primary energy sources. Exhibit 21 shows the modeled output per technology for every week in the calendar year 2050 for the 40, 60 and 80% RES pathway. It illustrates the fact that wind is (seasonally) negatively correlated with solar—solar produces more in the summer, while the opposite is true for wind. There is a similar counter-cyclicality in daily production between solar and onshore wind, which in most regions tends to produce more energy at night.

While interconnectivity enables exploitation of the negative correlation of wind with solar, there are periods during the winter (particularly in the 80% RES pathway) when the system has adequate capacity to meet demand but faces a shortfall in energy over a period of days or even weeks – illustrated in Exhibit 21 by the fact that a small amount of residual demand is met by OCGTs. This winter energy problem is exacerbated to some extent by the electrification of heat, which affects the winter load profile. This is a seasonal problem that is not easily addressable by expanding conventional forms of storage, such as pumped storage hydro, since to be commercial such conventional storage technologies must operate to capture the arbitrage across the "within-day" or "inter-day" price differences and therefore in this case would be recharged with

EXHIBIT 21

A combination of solar and wind is more stable than wind alone

Yearly energy balance, 20% DR, TWh per week



1 Storage included in the model relates to the existing hydro storage available across the regions

40. Archer & Jacobsen (2005): Evolution of global wind power; project analysis

energy from another source precisely during the period when energy is in short supply. For this reason, within the constraint of using only existing technologies, some limited use of natural gas-fired OCGTs as back-up capacity is necessary.

Most of the regions will rely on the diversity of generation sources to meet their peak demand. This will be from renewable resources within the region and/or neighboring regions via regional interconnection. Although interconnectivity is key to optimize the use of the European power system, most regions can fully supply their electricity needs, even at peak, with the "firm" generation capacity within their borders ("firm" meaning capacity that can be reliable dispatched, which excludes a large percentage of installed solar PV and wind generating capacity). The four regions that, at peak circumstances in high-RES scenarios, do not have sufficient firm capacity need an average contribution of 10% of the RES installed within their regions to meet peak demand.

5.3.4 Impact of Demand Response is significant

Demand Response (DR) is used in this report to mean demand that can be scheduled in the course of a day or even over a longer period in order to accommodate less controllable fluctuations in supply. It can be used both to temporarily lower demand when supply is insufficient, and to temporarily increase demand when supply is high (e.g., during high-wind conditions). In this study all pathways have been modeled both with and without DR. When DR is used, it has been capped at 20% of daily energy demand to be shifted within a 24-hour period.

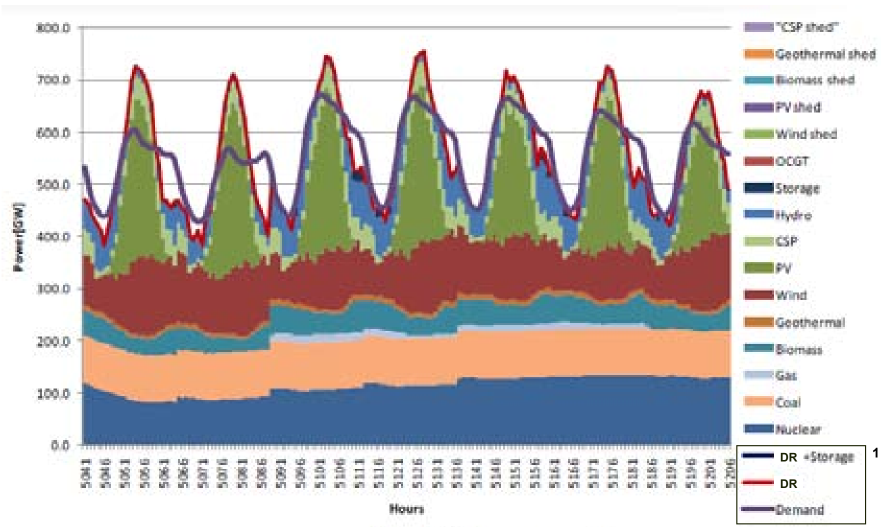
Exhibit 22 shows an example of the impact of DR. It represents a sunny summer week, where peak supply is higher than the "unmodulated" demand for every day of the week (purple line) due to high solar output. DR is used to shift demand and concentrate it during periods of peak supply, thereby avoiding RES curtailment and the opportunity cost associated with

EXHIBIT 22

Demand management helps to make demand follow supply, maximizing the utilization of RES

WEEK 32 – SUNNY WEEK

60% RES, 20% DR



1 The graph shows how the original demand line (purple) is shifted to a higher level (red line) by DR to capture the higher PV production

the loss of "free" energy. On top, shifting demand away from periods of low energy availability reduces the need for backup capacity. The significance of this effect has already been shown in section 5.3.2.

5.3.5 Sensitivities highlight robust results

All sensitivities described below have been performed on the 80% pathway with no DR except where otherwise stated. As this is the most ambitious pathway in terms of RES penetration, the effects of the modeled changes would be most pronounced.

Extreme weather conditions Extreme weather conditions can impact the production of one or more RES technologies. Setting up the system to deal with even more extreme events than already assumed for the base case[41] could require additional back-up capacity of up to 1.5% of total capacity installed. However, other measures (such as reducing interruptible loads) could be more appropriate.

Replacing PV, especially in Iberia, with wind capacity Replacing 25% of the PV capacity with onshore and offshore wind would lower requirements for transmission by about 25%. The requirements for generation backup capacity would not change. The France-Iberia power transfer capacity would be reduced by up to 45%.

Reducing transmission capacity between regions by 50% Limiting transmission capacity to 50% of that suggested by the study, with the same generation mix and geographical dispersion would lead to a significant increase in RES curtailment. While this reduction in transmission saves half of the capital expenditure on transmission, it is more than offset by the cost of curtailment of 15-20% of renewable output. If an electrical storage breakthrough would occur this would significantly reduce curtailment and reduce the additional generation capacity needed. The storage that would be needed to do this would be substantial, with a charging and discharging capacity of 125 GW and a reservoir capacity of 47 TWh (which is approximately 50% of Norway's existing reservoir capacity).

Decreasing generation plant flexibility Reducing ramp rates for fossil+CCS and nuclear by 50% (resulting in ramp rates for coal+CCS and nuclear of 20% of maximum output per hour and 25% of maximum output per hour for gas+CCS), causes minimal impact. Transmission, backup generation capacity and balancing services requirements don't noticeably change. Curtailment goes up from 3.2% to 3.9%. Overall running costs increase by less than 2% per year due to less optimal loading and therefore higher fuel use in thermal plants.

Increasing share of nuclear or fossil+CCS to 60% of production Increasing the share of nuclear to 60% in the 40% RES case, but still keeping fast-reacting technology like OCGT as generation back-up capacity, is technically feasible. This assumes a ramp-up and down speed of 40% of max output/hr for nuclear. LCoE would be 10-15% lower reflecting the lower OPEX of nuclear compared to coal/gas. If, instead, the share of coal+CCS and gas+CCS would be increased to 60%, at the expense of nuclear, the system would be about 10% more expensive, but would work well from a technological viewpoint.

Changing transmission technology mix Changing the AC vs. DC mix, and the mix between overhead lines (OHL) versus underground cable, does affect transmission investment significantly. The 80% RES pathway has total transmission investment costs of € 182 billion, of which €139bn is for inter-regional transmission (the remainder being for connecting offshore wind parks to the shore). Increasing the share of DC (from 27% to 50% of the total) in the inter-regional transmission mix would add about 10% to the transmission costs (or about € 14 billion). Changing the share of underground cable from 30% to 50% would add 60% to the transmission costs (€ 85 billion). Changing both the share of DC and the share of underground cable to 50% increases transmission costs by 50% (€ 70 billion)[42]. Chapter 6 will highlight that such an increase has little impact on the total cost of electricity.

41. See section 5.2.3 on the detailed assumptions for the base case in terms of extreme weather events.

5.3.6 Capacity build rates are high but technically feasible

The amount of additional generation capacity needed in a given year is a function of demand growth and the retirement of existing assets. Existing power plants that reach the end of their assumed economic lives (30 years for CCGT, 40 years for coal, 45 years for nuclear, 25 years for wind and solar, 50 years for hydropower, and 30 years for all other renewables) are assumed to retire. New fossil (with CCS) and nuclear plants are assumed to be added, with a total capacity ranging from 430 GW in the 40% RES pathway to 145 GW in the 80% pathway.

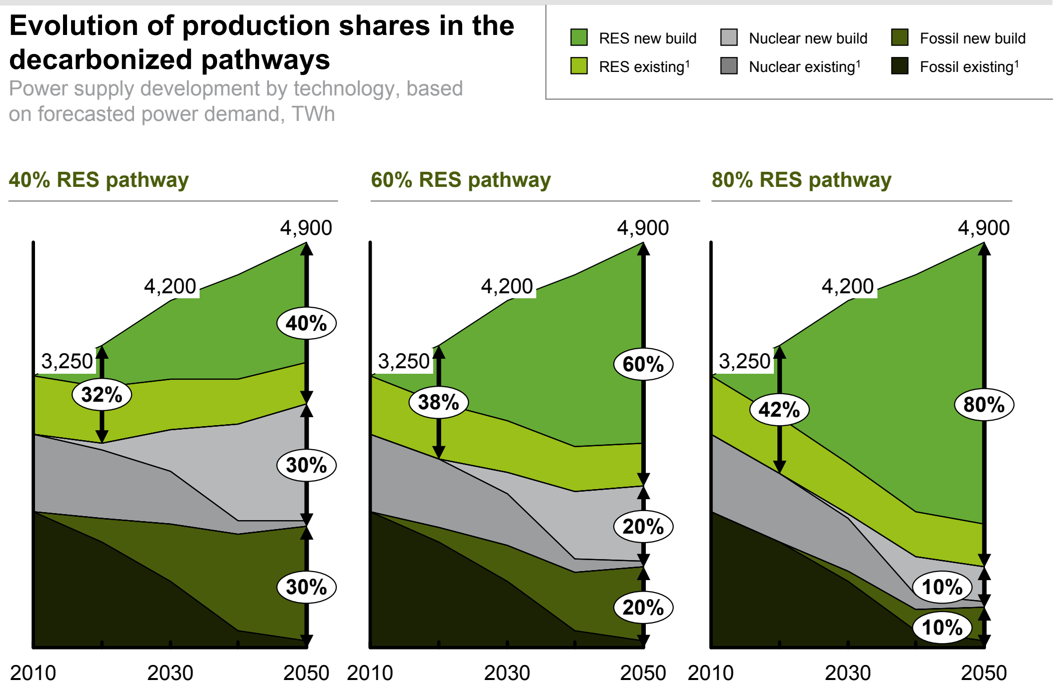
Growth in deployment of RES technologies does not exceed 20% per year by technology, and a linear build-up is assumed between 2010 and 2050 except for (i) onshore wind, which expands more quickly than average until 2020; (ii) offshore wind, which will grow more slowly than average until 2020 due to relatively higher costs, but faster than average from 2020-2040, due to higher availability of suitable locations compared to onshore; and (iii) large hydro and biomass build up, which develop in line with IEA/PRIMES assumptions. Nuclear will show low capacity increases up to 2020 due to construction, planning and permitting bottlenecks; after 2020 a linear build rate is assumed to reach the 2050 level of penetration. Given the back-casting approach used, the indicative capacity numbers for intermediate years should not be seen as predictions or used for detailed business cases.

The evolution of generation production per technology is illustrated in Exhibit 23. Translating these figures into new plants required per decade, the deployment challenge is seen to be reasonable (ranges indicate the requirements across the 40/60/80% RES pathways):

EXHIBIT 23

Evolution of production shares in the decarbonized pathways

Power supply development by technology, based on forecasted power demand, TWh



1 Existing capacity includes new builds until 2010

42. When moving to a higher cable mix, if a greater share of DC is used then the average cost falls because DC underground cable is lower cost than AC cables.

- 40 to 110 CCS gas plants need to build, compared with over 200 (without CCS) in the past decade (and about 100 in 1990-2000). Similarly, around 10 to 30 new coal plants with CCS will be required per decade, compared with 20 to 30 in the past decades (without CCS).

- For nuclear 20 to 65 new plants will be needed per decade, compared with 3 between 2000 and 2010, and 94 in the 1980s.

- For wind turbines, 25,000 to 35,000 onshore and 2,000 to 10,000 offshore turbines will be needed in every decade, similar to the 40,000 installed between 2000 and 2010. This is due to the fact that average turbine sizes grow from 2.5 to 3.0 MW (onshore) and 5-10 MW (offshore).

- Solar PV sees the biggest ramp-up in capacity, having to increase production threefold in the period 2010 to 2020 and tripling again in the decade after that. While this is significant growth, relative growth has been even faster in the past decade.

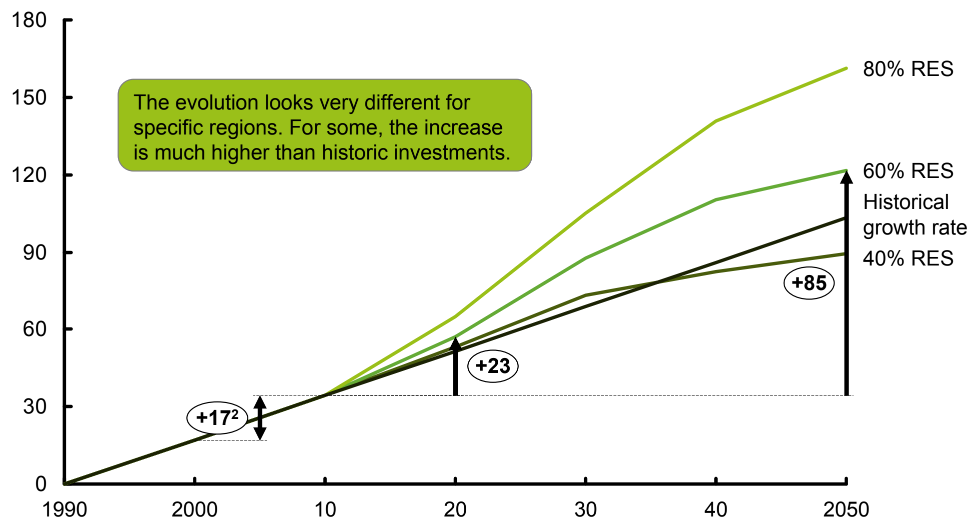
For the transmission system, to get the required capacity for the 60% RES pathway the build rate of the past decade needs to increase slightly, especially in the period from 2020 to 2040 as shown in Exhibit 24. As shown in section 5.3.2, the growth is not evenly spread throughout the regions—meaning that connections between some regions need to expand quite dramatically (most notably, between Iberia and France), while between other regions the required expansion is relatively modest (e.g., connections between the UK/Ireland and the rest of Europe need to grow from 2 GW (expanding to 4 GW in the summer of 2010) to 13 GW by 2050 (in the 60% RES pathway)). This might present a particular political or societal challenge in some regions, but it does not present an industrial challenge.

EXHIBIT 24

The rate of grid investments compares to historic investments at the European level

20% DR

GW, EU-27, Norway and Switzerland[1,2]



1 Development of grid is driven by the penetration of intermittent power sources (solar PV, wind onshore and wind offshore)
2 This assumes a linear build up of grid capacity in thousand GW km between 1990 and 2010, starting at zero, although some grid has been built even before 1990, i.e. UK-France and much of the Central European interconnections

5.3.7 Evolution of CO2 emissions in the power sector

In the baseline, emissions from the power sector until 2050 remain close to the 2010 level which is about 20% lower than the reference year 1990. The decarbonized pathways will reduce direct emissions from the power sector. GHG emissions from the power sector will be 35% to 45% lower in 2020 compared to 1990 levels, compared to 20% lower in the baseline. Assuming that coal plants built in 2011-2020 will be retrofitted with CCS in 2020-2030, and that all new fossil plants will be equipped with CCS from 2020 onwards, this improves to -70% in 2030, -90% in 2040, and -96% in 2050 (with little difference between pathways).

5.3.8 Potential next steps

The results presented in this chapter give a comprehensive view on the technical feasibility of achieving an almost fully decarbonized power system in Europe in 2050. The results are robust at a high level. Care should be taken when zooming in on a particular year, technology or region, as the analyses may not have been done on a sufficiently granular level to support this. Potential follow-up studies, for example in cooperation with ENTSO-e, could provide more regional or technology details.

CHAPTER 6

IMPACT OF POWER DECARBONIZATION ON THE COST OF ELECTRICITY

The levelized cost of electricity ("LCoE") is roughly the same in all three main pathways assessed, as a weighted average over the period between 2010 and 2050. The average LCoE for these three decarbonized pathways is about 10-15% higher than the weighted average LCoE for the baseline over a period of 40 years, prior to applying any price for CO_2 emissions. Applying a price of between €20 and €30 per tCO_2e would bring the baseline LCoE and the LCoE for these pathways roughly into equivalency with each other. The difference between the baseline and the decarbonized pathways is found to be slightly greater prior to 2030, but by 2050 the LCoE for the decarbonized pathways is within the range of LCoE for the baseline and trending lower, as shown in Exhibit 25 below.[43]

The costs of electricity in the pathways are within close range of the cost of electricity in the baseline due to an assumed increase in the costs of the baseline, an expected decrease in the costs of the decarbonized pathways, a higher level of integration of markets across Europe, and demand responsiveness to fluctuating supply.

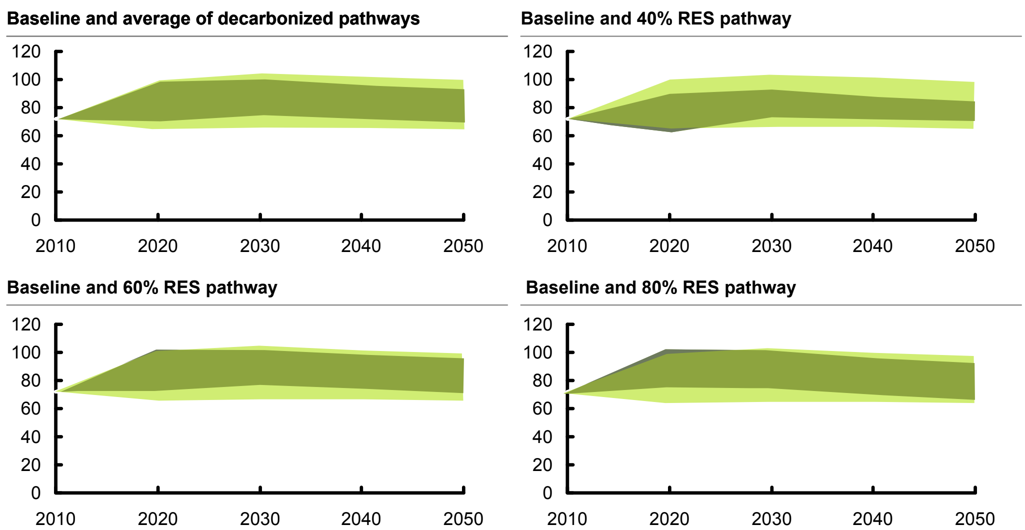
- *Increase in fossil fuel prices and CO_2 price*. Fuel prices are assumed to increase according to the IEA projection in their WEO 2009 report. Prices of coal and gas increase by about 60% over the

EXHIBIT 25

The higher RES pathways have higher cost of electricity in the early years

Ranges of the levelized cost of electricity of new builds¹, € per MWh (real terms)

Baseline
Decarbonized pathways



1 Based on a WACC of 7% (real after tax), computed by technology and weighted across technologies based on their production; including grid. LCoE ranges are based on: Carbon price from €0 to 35 per tCO_2e; Fossil fuel prices: IEA projections +/- 25%; Learning rates: default values +/- 25%

43. The range in LCOE is driven by the uncertainty in a combination of three major drivers of costs: CO_2 price (here ranged from €0 to €35 per tCO_2e averaged over the period), fuel costs (plus or minus 25% around the IEA projections), and the learning rates (plus or minus 25% around the base projections).

next 40 years, which is equivalent to a 1% annual increase (in real terms). The CO_2 cost applied in Exhibit 25 above ranges from €0 to €35 per tCO_2e. This is lower than the CO_2 price that is projected to develop under the IEA 450 scenario. It reflects an average price, with some technologies requiring a carbon price beyond such levels to be in line with conventional generation.

- *Decrease in the cost of (low carbon) technologies*. Mature technologies like those that dominate the baseline supply portfolio (coal steam plants, gas-fired combined cycle and nuclear) are not expected to experience dramatic improvements in cost and performance over the period. Emerging technologies like those that constitute a large share of the pathway supply portfolios (e.g., solar PV, offshore wind) have historically experienced significant and consistent rates of cost improvement with each doubling of production until they reach maturity. In this study significant cost reductions are assumed for these technologies (see chapter 3 for more details).

- *Impact of network investments*. The decarbonized pathways require more grid investments, ranging from € 50 to over € 200 billion over 40 years. However, the impact on the cost of electricity remains relatively small, as the total power-system related capex over the same period amounts to about €2 trillion and operating cost remain a large share of the total costs. More importantly, this investment in networks[44] is a key factor in moderating the costs. The investments in networks dramatically reduce curtailment of generation resources and requirement for back up plants.

This report reflects a deliberate choice not to articulate point projections of future cost of electricity for specific production technologies. Such projections are commonly used to forecast an optimum (e.g., "least cost") outcome. Future costs for individual technologies are notoriously difficult to predict with meaningful accuracy more than a few years out, especially for developing technologies.

The costs are compared on an average weighted cost of electricity delivered to end users basis. It includes the costs of generation, grid and back up, associated with a system that delivers power to a reliability standard of 99.97% (target, not currently achieved).

The cost of electricity analysis is based on the aggregation of plausible, widely vetted projections of the cost and performance of the generation and grid technologies deployed into a range of power system pathways. While any projection of cost and performance for an individual technology is certain to be either too high or too low, it is more likely that forecast errors would cancel each other out in a diversified basket of technologies, such that overall LCoE should be sufficiently robust to be insightful.

Fact box: "Levelized Cost of Electricity" calculation methodology

The unit cost of electricity in the baseline and the decarbonized pathways are compared using the "levelized cost of electricity" (LCoE) industry standard. The LCoE reflects the revenues that an investor would need to obtain to justify investments into power generation and grid. These revenues could be raised from consumers, wholesale, trading or governments/ regulators. The LCoE is an important determinant of but is not the same as the power price, which is set by a combination of market mechanisms (for generation costs) and regulation (for transmission and distribution charges) and might include taxes and other levies.

The LCoE is calculated by dividing the present value of capital and operational costs over the discounted production volume of the asset over its lifetime. A more detailed overview of the methodology is provided in the online Appendices.

The same cost of capital (WACC) of 7% real after-tax is assumed for all technologies. This approach avoids favoring or disfavoring certain technologies. The LCoE does not include

44. See earlier discussions of "smart grid" investments; incremental distribution investment was not studied, but a survey of recent studies points toward the conclusion that the incremental impact on LCoE is likely to be small.

distribution, and transmission requirements assume "effective" capacity, so additional capacity needed to deal with, e.g., n-1 security levels needs to be added. The LCoE does not include a carbon price.

6.1 DEVELOPMENT OF FOSSIL FUEL PRICES

Fossil fuel prices are modeled as per the IEA WEO 2009 *"450 Scenario"* (which projects lower future prices than the WEO 2009 "Reference" scenario due to the assumption of lower future demand). The WEO 2009 projections carry out to 2030, after which prices have been assumed to stay flat in real terms through 2050. Coal increases from $70 per tonne today to $109 (real) in 2050; natural gas increases from $8.90 to $14.80 per mmBtu; and oil increases from $80 to $115 per barrel. This study assumes that the fossil fuel prices in the baseline are the same as in the decarbonized pathways, even though Europe will use less fossil fuel in the latter situation. The cost of electricity in the baseline is more sensitive to fuel price changes. If the fuel price increases by 25% more than assumed (i.e., oil to $150 per barrel), the cost of electricity increases €5 per MWh in the baseline, versus €2 in the 80% RES pathway, and vice versa. Hence, assuming all other drivers stay constant, higher fuel prices narrow the gap and lower prices widen it. A major departure from the IEA forecasts would be required to materially change the relationship between the baseline and the decarbonized pathways.

6.2 LEARNING RATES OF GENERATION TECHNOLOGIES

Capital costs are assumed to reduce over time in real terms. A learning rate approach is followed. For mature technologies, like coal, gas, geothermal and hydro plants, the annual improvement is 0.5% per year. Costs for biomass and geothermal plants improve by 1% per year. Capital costs for nuclear only improve slightly as nuclear is a mature technology. A learning rate of 3 to 5 % is applied to the portion of the capex that is new to Gen-III designs. This leads to a cost reduction of less than 10% over 40 years.

The capital costs for CCS are assumed to drop by 12% per doubling of installed capacity, in line with the report "CCS, assessing the economics" from 2008. The capital costs for wind onshore and offshore improve with 5% per doubling of cumulative installed capacity. The solar PV learning rate is assumed to be 15% per doubling of installed capacity, both for wafer-based and for thin film. This is an average of a higher learning rate on the module and a lower learning rate on the balance of system and installation costs. Solar CSP costs are assumed to drop from € 5,000 to €2,500 per MW, including molten salt storage facilities for six hours of storage. For grid investments, no learning rate or shift in the underground/overhead ratio is assumed (currently 27/73%).

Operational costs also improve over time. The efficiency improvements for gas and coal plants lead to reductions in fuel usage and therefore imply a cost reduction per MWh produced. Yearly maintenance cost for wind onshore turbines are assumed to remain at 2% of initial capex and therefore reduce with the reduction in capex over time. With an increase in load factor for new onshore wind turbines from 25%-30% in 2010 to 35% in 2050 the maintenance cost per MWh produced reduce further. The same effect is expected for offshore wind as the load factor of new turbines improves from 37% in 2010 to 45% in 2050. In addition maintenance costs are assumed to reduce from currently 3% of initial capex per year to 1 - 2% in 2050. For solar PV the maintenance costs are assumed to stay at 1% of the initial capex and for solar CSP at 3% share of the initial capex. Opex of biomass plants mainly consists of fuel costs which is assumed to reduce from € 49 per MWh in 2010 to € 34 in 2020 and further to € 29 in 2050, at the same time the fixed yearly opex is assumed to remain at 0,5 -1,0% of the initial investment. Fixed opex for geothermal plants is assumed to reduce from € 100 per kW to € 60 in 2050. For nuclear and hydro no improvements in operational costs are assumed.

The results are sensitive to the amount of learning that can actually be realized. A 50% lower learning rate for all technologies will result in an increase in cost of electricity in 2050 of € 2 per MWh in the baseline versus € 12 per MWh in the 60% RES pathway, and vice versa. If only the solar learning rate is halved, the increase would be € 8 per MWh.

6.3 CAPITAL INTENSITY

All low-carbon technologies carry a relatively high capital cost, whether it is nuclear, CCS or renewable energy. Capital expenditures for the power sector increase by 50% to 110% in the decarbonized pathways compared to the baseline. This is due to a combination of a higher investment cost per MW and the fact that more capacity is needed due to lower load factors (e.g., for solar and wind). Additionally to higher generation capital investments, the non discounted capital requirements for grid and back up plants over 40 years range between € 110 to € 200 billion in the 40%/60%/80% RES pathways (including demand response), yet they only represent about 10% of the generation capex cost.

As the pathways are capital intensive, a reduction of the cost of capital from 7 to 5% would improve the cost of electricity by € 11 per MWh in the 60% RES pathway, compared to €7 per MWh improvement in the baseline.

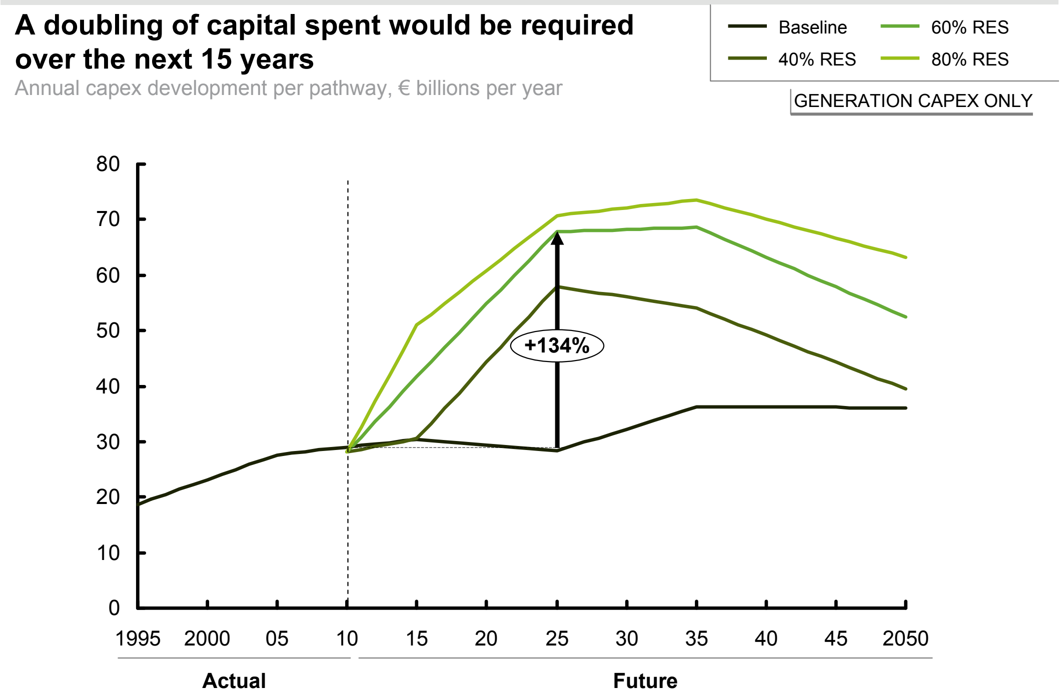
Generation capital costs The actual capital spent over the past decade on power generation capacity has been €25-30 billion per year; in the decarbonized pathways this would rise rapidly to €55-70 billion per year between 2020 and 2035, after which it would gradually decline in the last 15 years up to 2050. This is illustrated in Exhibit 26.

Should the transformation to the decarbonized pathways be delayed by 10 years while still meeting the 2050 target, the required annual capital spent will peak at € 90 billion, tripling compared to today's levels and potentially resulting in significant additional cost and stress on the supply chain. In addition, the CO_2 emitted between 2010 and 2050 would be significantly higher.

EXHIBIT 26

A doubling of capital spent would be required over the next 15 years

Annual capex development per pathway, € billions per year



Transmission and backup plant capital costs Next to investments in generation capacity, investments in transmission and backup generation capacity will be necessary. The investments increase in line with the penetration of wind and solar PV energy, given the intermittent nature of these technologies and their uneven distribution across Europe. As discussed in chapter 5, continuing the investment rate of the past 20 years for the period 2010-2050 would realize close to the required interregional transmission capacity for the 60% RES pathway (Exhibit 26).

While the costs for transmission and backup capacity are by no means small, they are significantly less than the investments required for generation capacity. Total transmission, backup generation and balancing services costs constitute about 10-15% of the LCoE. Exhibit 27 details these requirements per pathway.

6.4 OPERATIONAL COSTS

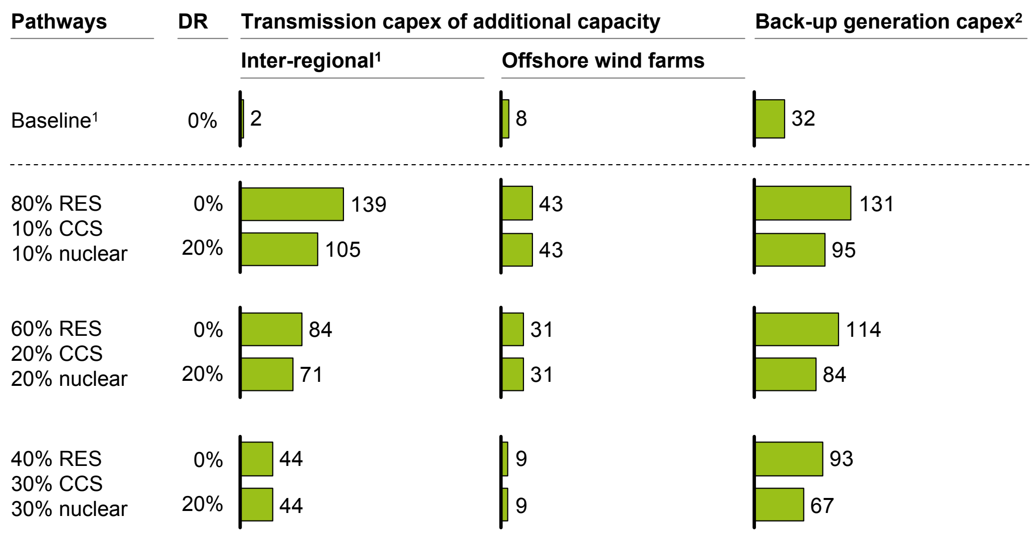
Operational costs are highest in the baseline and lowest in the 80% RES pathway. Operational costs in the baseline are relatively high due to the higher fuel consumption and higher share of gas plants. The 40% RES pathway has less gas plants, but more costs related to CCS fuel efficiency loss. The non-discounted cumulative OPEX for the period 2010-2050 for the baseline is around €7.2 trillion, not including carbon costs. This declines by around €1 trillion in the 40% RES pathway, €1.1 trillion in the 60% RES pathway, and €1,5 trillion in the 80% pathway. The OPEX reduction almost fully offsets the CAPEX increase.

Exhibit 28 also highlights how the yearly total capex and opex spent increases up to 2030 and decreases thereafter. The increase of opex until 2030 originates from an increase in fuel prices until 2030 and an increase in total electricity demand. The significant capex increase due to the buildup of CO_2-free electricity production also peaks in 2030

EXHIBIT 27

Transmission and back-up related capex both increase with a higher share of intermittent RES

Cumulative capex from 2010 to 2050, € billion (real terms)



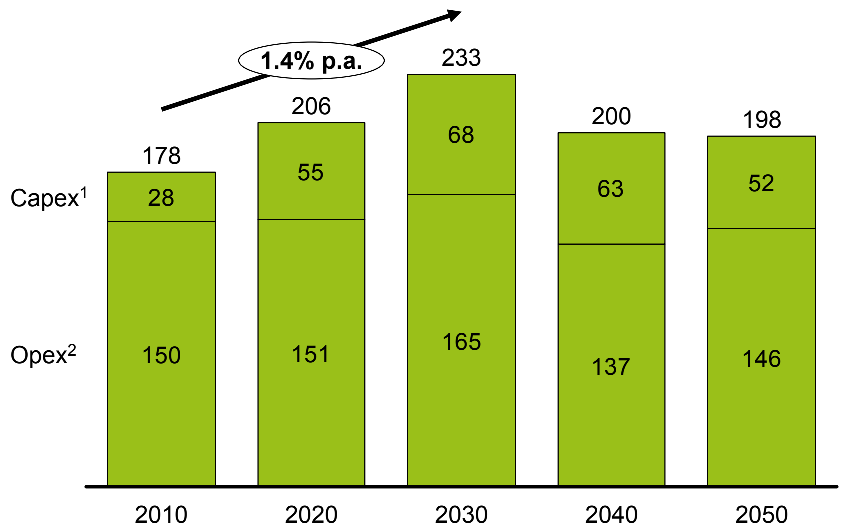
1 Based on an average transmission mix with 73% AC and 27% HVDC (comparable to the Tradewind report) at a cost of € 1,000 MW per km
2 The cost of additional capacity is assumed to be 350,000 € per MW based on OCGTs, but could be any equivalent

EXHIBIT 28

Total power costs increase up to 2030 due to increasing fuel prices and capital investments

60% RES PATHWAY

Total annual capex and opex, € billion per year



1 Capex is for new builds for generation as well as grid and back-up capacity
2 Opex covers operational expenses for the entire generation fleet

and reduces thereafter. Inefficient plants are retired around 2030-2040. Finally in 2040 and 2050 a level is reached where the additional 40% of electricity production compared to 2010 is produced by only 10% additional opex and capex.

6.5 COMPARING THE COST OF ELECTRICITY

Towards 2050, the cost of electricity across the baseline and decarbonized pathways are similar. In the first two decades, the costs for the 40% RES pathway are lower than for the 80%RES pathway.

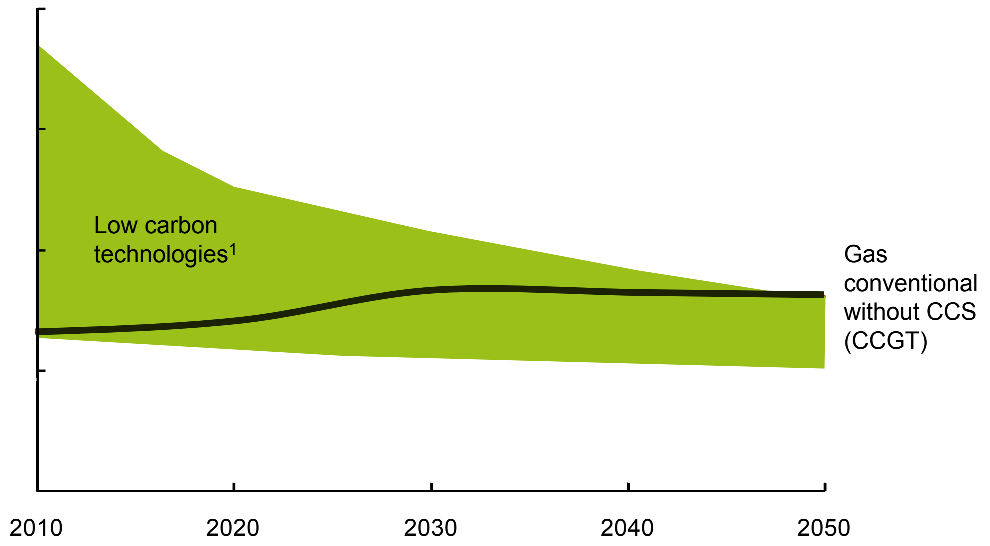
The LCoE for RES is higher at the beginning of the period than at the end, reflecting cost reductions due to technology learning and reducing use of fuel. Due to technology improvements, the costs of the various RES technologies are converging. At the same time, LCoE for conventional thermal plants increase, with the assumed rise in commodity prices projected by the IEA. Combining these two factors results in the LCoE of a gas fired power station without CCS (CCGT) crossing the upper boundary of the envelope of the LCoEs for the various low-carbon generation options in 2050 (Exhibit 29).

The uncertainties around the LCoE can also be presented in terms of the average household bill for electricity. Depending on how the various cost drivers develop, the costs of the power bill for an average household are unlikely to be more than €250 per year different between the baseline and the pathways, as described in Exhibit 30.

EXHIBIT 29

Low carbon technology costs decrease while gas plant costs increase

LCoE evolution of gas conventional compared to low carbon technologies, € per MWh (real terms)
Example based on the 60% RES / 20% nuclear / 20% CCS pathway, Iberia

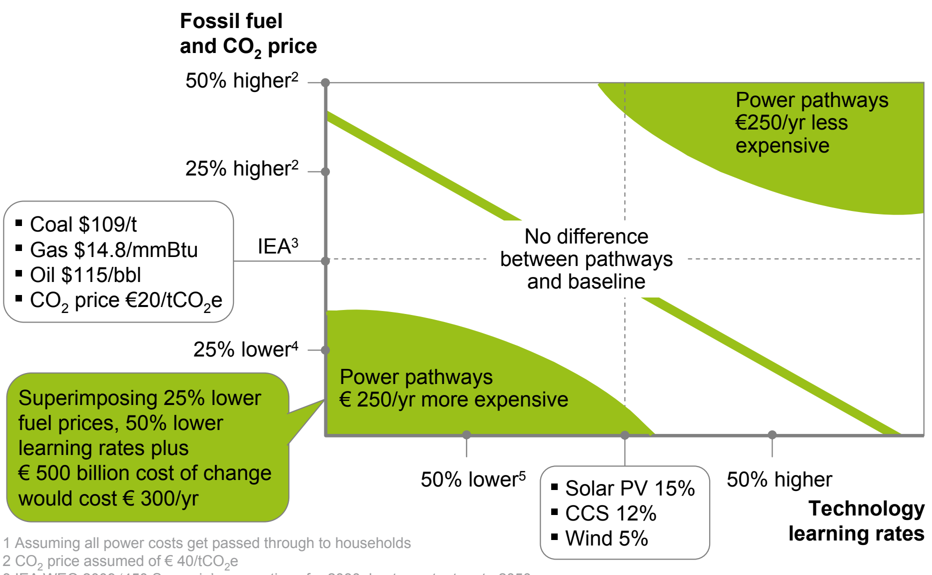


1 Technologies included: Coal CCS, Nuclear, Wind onshore and offshore, Solar PV, Solar CSP and biomass dedicated

EXHIBIT 30

The cost of the decarbonized pathways and the baseline are likely to differ less than € 250 per year per household

Cost impact of the decarbonized power pathways per year per household[1]



1 Assuming all power costs get passed through to households
2 CO_2 price assumed of € 40/tCO_2e
3 IEA WEO 2009 '450 Scenario' assumptions for 2030, kept constant up to 2050
4 No carbon price
5 For all technologies. Learning rate is defined as capex improvement per doubling of cumulative installed capacity

CHAPTER 7

FURTHER OPPORTUNITIES: EXPANDING GEOGRAPHIES AND BREAKTHROUGH TECHNOLOGIES

The three pathways described in the previous chapters highlight how the power sector could be decarbonized by producing electricity within Europe, using only technologies that are currently at least in late stage development. This chapter describes the additional opportunities to expand into alternative geographies holding large renewable energy potential and/or to leverage potential "breakthrough" technologies that could become commercially available at scale in the next 40 years and be as attractive or more than the currently available technologies. As such, these two options could represent a significant upside compared to the pathways analyzed. Moreover, additional technologies not described here may also evolve to complement these technologies.

Finally, section 7.3 tests the implications on the LCoE of expanding the 80% RES pathway to 100% renewables by leveraging 15% of CSP in North Africa and 5% of enhanced geothermal. Chapter 5 highlighted that such a scenario would be technically feasible, and this section shows that it is likely to come at a cost of only 5 to 10% more than the 60% RES pathway.

Importantly, there is no judgment as far as comparing the feasibility of either the geographies expansion or the breakthrough technologies. Both options face completely different challenges: expanding geographies would require solving political and regulatory issues, while breakthrough technologies rely on research and development.

7.1 IMPORTING RENEWABLE ENERGY FROM NEIGHBORING REGIONS

The main decarbonization pathways presented in this report have been developed excluding zero-carbon electricity imported from outside of Europe, as is the case with breakthrough technologies. The intention is to minimize complexity and uncertainty in order to develop as clear and robust an answer as possible to the question of the feasibility of power sector decarbonization. Having done so, however, it is worth emphasizing that the development of premium renewable resources in neighboring regions offers significant upside potential, both for Europe and for the countries of origin. These options include outstanding geothermal resources in Iceland and Turkey, solar resources in the Middle East, solar and wind resources in North Africa and biomass imports from Russia and Ukraine.

Imports of North African renewables in particular have been included in the assessment of the 100% renewables scenario, and the results point to the potential for Europe and her neighbors to reap significant benefits from the development of this option over the period leading up to 2050. Recent initiatives, including the Desertec Industrial Initiative and the Mediterranean Solar Plan, point to the growing realization that this option holds great potential, not only in inexhaustible zero-carbon energy supplies for consumers in the host country and in Europe, but also in regional economic development, neighborhood security, and development of European clean technology export industries. European attention has understandably been focused on the tremendous solar energy potential in the region, but there are also attractive opportunities in wind energy, particularly in the western part of the region.

While wind and solar PV have great potential in North Africa, there are plentiful wind and PV opportunities in Europe as well. The opportunity that perhaps sets the region apart most notably is the potential for Concentrating Solar Power, or CSP. The ability to add thermal storage systems to CSP plants makes them of particular interest from a system operation perspective, because they can be relied upon throughout the day and evening and turned up or down in response to demand. CSP with storage requires ample space, relatively level terrain and high rates of direct normal insolation, traits that in combination are in limited supply in Europe but are effectively unlimited in North Africa.[45] The fact that Saharan insolation rates remain robust through the winter months adds even more value to the resource. There are no real technical challenges in bringing production from interior North Africa to Europe; high-voltage DC cables are well developed and transport large quantities of electricity comparable distances with minimal losses in several parts of the world.

Thus North Africa offers the best opportunity proximate to European markets to develop beneficial CSP technology at large scale. The objection often raised with this option is that of security of supply. Some are concerned that Europe's security of energy supply would be reduced due to concerns about vulnerability to political instability in the host countries. Upon close inspection, however, it is likely that these concerns are overstated. The 15% of total EU supply assumed in the 100% renewable scenario would mean no more than about 5% of total supply coming from any single country, and the power would flow across tens of individual export cables. Thus the share of total supply that would be exposed to individual points of disruption is of a magnitude that European system operators plan against today in the normal course of business.

Of more practical concern is the complexity of organizing such a project both financially and politically. These challenges are very real, and the economics of building and maintaining large CSP in the Sahara are not yet clear. Addressing these issues sufficiently to enable imports to develop at any significant scale will require a coordinated, multi-year effort between industry, governments and regulators on both sides of the Mediterranean. Equitable benefit and burden sharing will have to be worked out between importing and exporting countries. Frameworks must be established to enable development of the cables free from the risk that they would be co-opted by other forms of generation.

For these reasons it is unlikely that material quantities of imported renewable production from North Africa will be a practical reality in the near to medium term. Yet the potential benefits, to Europe and to neighboring countries, are such that it would seem prudent to plan on the basis that such imports could be playing a significant role in Europe's electricity supply in the longer term.

7.2 BREAKTHROUGH TECHNOLOGIES

This section describes potential "breakthrough" technologies that could become commercially available at scale in the next 40 years and be as attractive or more than the currently available technologies. Many technologies are being researched beyond this list which may also evolve to complement these technologies.

Vehicle-to-grid (V2G) is the ability of the grid operator to discharge the battery of an EV to access the energy to assist in balancing the grid. The potential would be limited by the EV user either by defining their usage pattern (i.e. ensuring sufficient charge to complete their next journey) or by making a percentage of the battery capacity as available. Assuming 30 kWh batteries, for EVs that are available and connected to the grid 50% of the time, with 20% capacity available for use by the grid operated this could provide approximately 1% of the TWh storage capacity available in Norway. In addition, technical barriers need to be overcome to improve battery life with increased cycling without increasing the cost of the battery to the user beyond the economic value of the service that they provide to the grid operator. If these barriers can be overcome, V2G could allow the transmission expansion to be cost-optimized at

45. Many observers raise concerns about water use by CSP plants in desert areas, however dry cooling is a well proven technology, reduces water consumption by 90% or more, and has limited impact on plant efficiency.

a lower quantity of new inter-regional transmission capacity.

Large scale storage concepts have been around for more than a century, but the expansion of intermittent supply options has led to renewed focus on innovative approaches. Compressed Air Energy Storage (CAES) is one such idea, in which air is pumped into underground reservoirs under high pressure, to be released at a later time to drive a turbine. Facilities with a rated power of more than 100 MW have been installed in Germany and the US, both being in operation for several decades already. Research on advanced adiabatic CAES is ongoing. This will increase the round trip efficiency from the present 50-60% up to some 80% and, besides, would enable operating this type of facilities without adding natural gas. Different approaches are being studied for shifting large quantities of bulk energy economically over periods of weeks or months, including the storage of energy chemically.

Enhanced geothermal is a large scale, non-intermittent renewable energy source that is currently in pilot testing phase. A 3 MW plant is commissioned in Landau, Germany, with several larger projects planned in Italy (over 300 MW). The current capital cost amounts to approximately € 5,000 per MW. Power is produced by using naturally occurring dry geothermal energy to flash water into high pressure steam, which drives a turbine that generates power. Key risks are related to hot well drilling (up to 10 km depth), earth movements that could fill the well, and (local) resource depletion that would require a new well to be drilled. Its energy source is truly renewable, as the earth contains large amounts of heat. Some technologies, however, consume water. Enhanced geothermal technology can be applied anywhere in Europe, but is most cost effective where the heat is closer to the surface. An alternative is based on extracting heat from shallower depths (1 to 2 km in depth). The heat can be used directly for heating. Pilots are common, e.g., in greenhouses in the Netherlands. Key technology development goals are to improve the reliability of hot well drilling and to understand better the drivers of resource depletion. The first commercial applications are expected by 2020.

Nuclear fusion has been pursued for decades. The technology is consumes relatively small amounts of deuterium and tritium extracted from (ocean) water. A pilot plant (ITER) is being constructed in Cadarache, France. No electricity will be produced; its focus is on proving the technology. Nuclear fusion is a non-intermittent, large-scale technology. It is expected to produce less high-level nuclear waste than a nuclear fission power plant and is believed to be inherently safer. A long development period is foreseen, making it unclear whether this technology could be deployed at large scale by 2050. Key development challenges are related to its technical complexity and the need to control the fusion process.

Nuclear fission Gen IV reactors are being developed that will consume less feedstock, making this a long-term energy source. Improvements in economics as well as safety features are being pursued.

New solar technologies are being developed that could increase the potential and reduce costs. Several land-based technologies are being developed that are in demonstration or early commercial phase, e.g., concentrated solar and organic solar panels, A more far out option is the solar power satellite, where power is generated from a platform of satellites in geosynchronous orbit at about 36,000 km.

Biomass from algae could deliver a large and reliable energy source for thermal plants, potentially equipped with CCS, which would make the installation CO_2 reducing. Pilot plants are being developed, primarily with the aim to produce biofuels for transportation (e.g., the Shell project in Hawaii). Algae farms produce optimally in warmer climates and high solar radiation so it's unclear whether this will become an important power generation technology for Europe.

Wave energy could represent a fair potential of the future power demand in Europe. Power is withdrawn from surface waves by mechanical devices. It is an intermittent source. It is in pilot phase with 4 MW installed capacity in 2008. Potential applicability is mostly in Norway, Scotland and Ireland. Technology learning rates have been slow and finding suitable locations is a challenge due to potential conflicts for use of coastal space with other maritime activities. Operation and maintenance costs are expected to be relatively high.

Tidal energy is a relatively small energy source. If costs are attractive, it could become an interesting and locally significant technology. Two categories are being developed: tidal current systems make use of the kinetic energy of moving water to power turbines, and tidal barrage systems use potential energy in the height difference between high and low tides. It is a non-intermittent energy source. Tidal current is in pilot phase, with 2 MW installed in 2008. Tidal barrage has one plant of 240 MW operating in France. The key limitation is the availability of coastal locations.

Saline gradient energy is a relative small energy source that cannot produce more than 5% of the European power demand. It uses the difference in salt concentration at river-sea interfaces. It is a non-intermittent source that is currently in early research stage of development. Statkraft commenced operation of the first commercial salinity gradient power plant in November 2009 (about 3 kW). Key development challenges are the lack of experience of performance and environmental impacts from full-scale sea trials, and the need to develop a semi-permeable membrane with high efficiency and durability.

Other technologies have been developed that are unlikely to become successful at large scale. The European seawater temperature gradient is too low for ocean thermal energy. Gravitational energy like Piezo-electric sensors and flywheels are technically challenging and capture relatively little energy.

7.3 100% RES SCENARIO: TESTING ITS ECONOMICS

The 100% RES scenario was tested to be technically feasible and equally reliable. It leverages enhanced geothermal systems technology and imports of North African CSP (a commercial technology). Its levelized cost of electricity could be within 5% to 10% of that of the 60% RES pathway.

Generation mix The 100% RES scenario replaces fossil and nuclear supply technologies from the 80% RES pathway with RES dispatchable ones: 15% solar CSP (including 6 hours of thermal storage) from North Africa and 5% enhanced geothermal. Neither of these options is deployed in the other three pathways studied for reasons that have been touched on elsewhere; both are firm, dispatchable renewable sources, (in the case of CSP with thermal storage, for up to 15 hours per day).

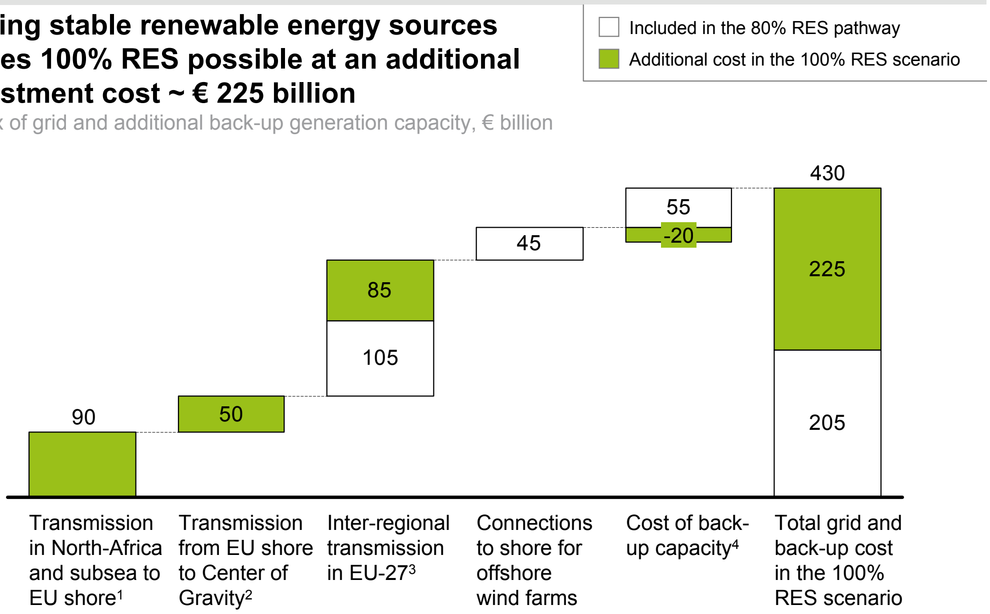
Grid and backup implications With 15% of its electricity produced in North Africa, this scenario relies on an extended infrastructure to bring North African power supply to entry points into the European grid via undersea HVDC cables. For this quantity of imports, the number of individual cables could ultimately run into the dozens, a significant benefit for security of supply. Also, significantly more transmission is required to reinforce the grid within Europe to take this electricity away from the entry points and integrate it into the European wholesale grid. Altogether, an additional € 225 billion is required for these transmission investments, roughly doubling the capital requirements for the 80% RES pathway. Specifically, the additional inter-regional transmission capacity would be 330 GW and 215 GW, without and with 20% DR respectively, and excluding the link from North Africa to Europe. The corresponding backup and balancing generation capacities, on top of the baseline, would be 210 GW and 95 GW respectively. Curtailment would reach 5% and 2% without and with DR respectively.
With the additional transmission, and because the new supply is roughly as firm and dispatchable as the nuclear and fossil generation it's replacing, backup capacity requirements are actually reduced somewhat compared to the 80% RES pathway (215 GW compared to 270 GW) but this backup is used more extensively, and therefore emission levels reach 7% if backup is assumed to be OCGTs and with demand response. This also implies higher operational costs from these backup plants. These transmission and backup plants cost implications are summarized in Exhibit 31.

LCoE 5 to 10% higher than the 80% RES pathway
The LCoE of the 100% RES scenario has been

EXHIBIT 31

Adding stable renewable energy sources makes 100% RES possible at an additional investment cost ~ € 225 billion

Capex of grid and additional back-up generation capacity, € billion



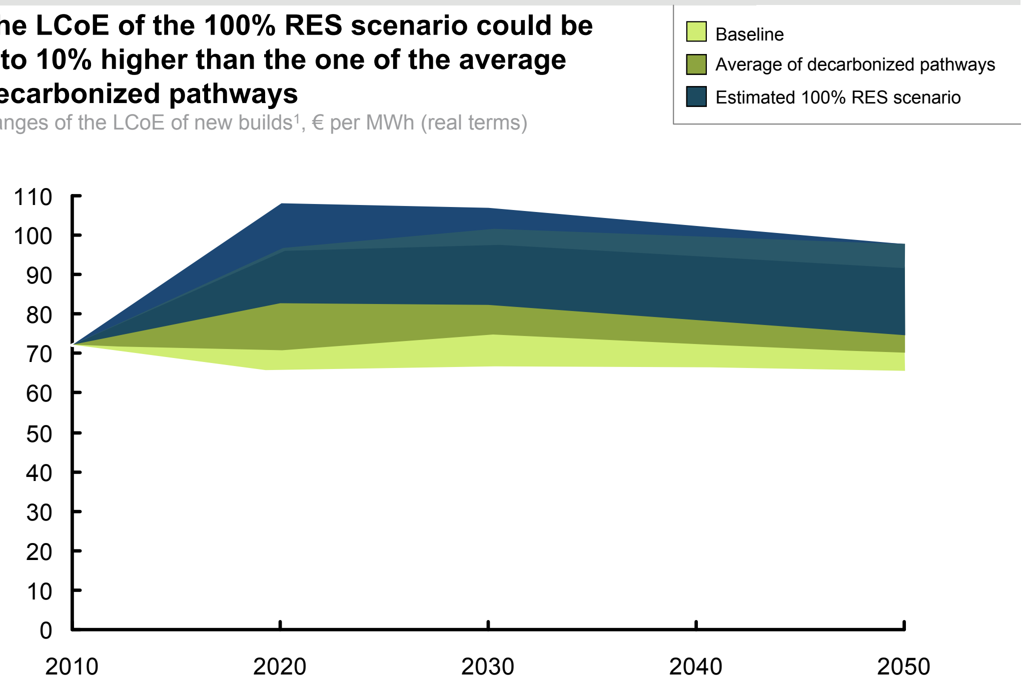
1 North African onshore transmission requirements and subsea connections to the European continent, all HVDC
2 All HVDC transmission with 20% cable and 80% overhead line
3 Requirements in transmission reinforcements to spread the electricity across the various regions from the Centers of Gravity in Southern Europe
4 With higher transmission in Europe, back-up requirements with demand response are lower in the 100% RES pathway, with 75 GW, compared to 95 GW in the 80% RES pathway

assessed with a greater range of uncertainty in the results, due to (i) uncertainty about the costs to build and operate large-scale CSP in interior North Africa, and (ii) the early stage of development of EGS. The main drivers of difference in LCoE between the 80% RES and 100% RES pathways will be the larger grid deployment and the view taken on the cost of generation from CSP in North Africa delivered to Europe relative to the nuclear and fossil-with-CCS generation it is replacing. With higher and more consistent (across seasons) rates of direct normal insolation generating costs are likely to be lower than for CSP in Europe; because of the larger potential scale of deployment, learning opportunities are likely to be greater than for CSP in Europe. Experience with EGS is limited, so cost estimates span a wide range and carry a high level of uncertainty. It is assumed to be similar to the CSP one in the following LCoE estimates. Ultimately, accounting for both the impact from generation and grid, the LCoE can be estimated at between 5 to 10% higher than that of the 60% RES pathway. Exhibit 32 illustrates an estimated range for this LCoE and compares it to the ranges for the baseline and the average of the decarbonized pathways (as illustrated in Exhibit 25). Significant ramp-up of EGS and North African imports is unlikely prior to 2030, so the 80% and 100% pathways should closely resemble each other prior in the 2010-2030 period. Exposure to learning rate assumptions in this scenario is obviously higher.

EXHIBIT 32

The LCoE of the 100% RES scenario could be 5 to 10% higher than the one of the average decarbonized pathways

Ranges of the LCoE of new builds[1], € per MWh (real terms)



1 Based on a WACC of 7% (real after tax), computed by technology and weighted across technologies based on their production; including grid. LCoE ranges are based on: Carbon price from €0 to 35 per tCO_2e; Fossil fuel prices: IEA projections +/- 25%; Learning rates: default values +/- 25%

PART C:

IMPLICATIONS ON THE ECONOMY

CHAPTER 8

MACRO-ECONOMIC IMPLICATIONS OF DECARBONIZATION

In this chapter the decarbonized pathways are assessed on overall cost to society, dependency on fossil fuels, macroeconomic growth, job creation and sustainability. No material difference was found in the macro-economic impact across the 40% RES, 60% RES an 80% RES decarbonization pathways; the specific results referenced here relate to the 60% RES pathway unless otherwise noted.

Decarbonization has a small positive overall (direct) effect on the total cost to society in the long term, with substantial upside potential based on historical experience with similar periods of industrial transformation. The overall effect is immaterial in the short to medium term, with a slight (0.02%) decrease in the rate of growth in the first decade. Capital requirements are higher, especially in the first decades. The advantage over the baseline over time can be attributed primarily to a lower cost of energy per unit of GDP, due to increased energy efficiency and to a shift from fossil fuels to electricity in much of the transport and he ating sector. Reliance on fossil fuels and energy imports reduces significantly. This brings additional benefits like a reduced vulnerability of the economy to potential future oil & gas price spikes. Finally, sustainability is greatly enhanced as emissions of CO_2 decline by 80%. Emissions of pollutants such as particulates, NOx, SO_2 and mercury are also significantly reduced. Depletion of fossil fuels is greatly reduced. At the same time, requirements for steel, copper and rare metals may increase.

8.1 END TO END COST AND CAPEX FOR SOCIETY

Compared to the baseline, capital costs will increase significantly over the next 40 years and operational costs will come down. The net effect is a reduction in full cost to society of € 80 billion per year in 2020, rising to € 350 billion per year in 2050.

8.1.1 Capital costs

As illustrated in Exhibit 33, the decarbonized pathways require about € 2,750 billion more capital than the baseline, or about € 50 billion per year on average. This is a net effect of less capital requirements for the fossil fuel value chains (oil, coal and gas) and a higher capital requirement for energy efficiency measures and the power sector, as described in chapter 6. The total capital costs can be split in costs for the power sector, costs for primary energy, and non-energy investments.

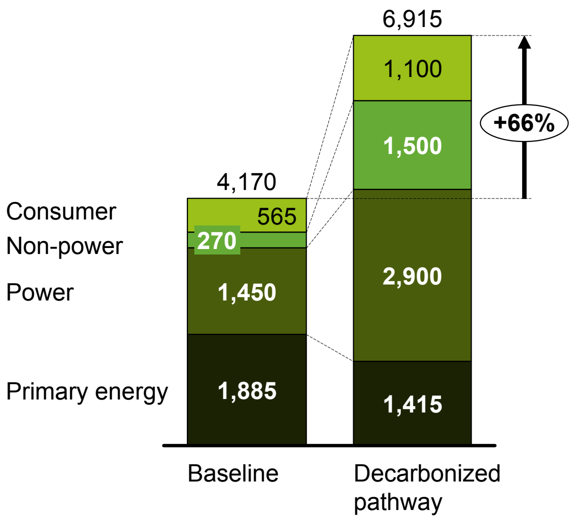
The capital requirement for the power sector increases from about € 1,450 billion to € 2,900 billion over 40 years. This capital increase is based on the 60% renewable pathway. For the 80% renewable pathway the number would increase by another € 300 billion over 40 years.

The capital requirements for the primary energy sector (the oil, gas and coal industry) are assumed

EXHIBIT 33

The decarbonized pathways require up to 70% more capital for all energy sectors, driven by more efficiencies and a shift away from oil

Cumulative capex 2010-50, € billions



Note: Includes additional capex for EV batteries and fuel cells for vehicles (in total approximately € 500 billion)
SOURCE: IEA WEO 2009 (fossil fuel capex 2010-30, assumed constant 2030-50), McKinsey Global Cost curves, team analysis

to decline in proportion with reduced demand. This implicitly assumes that the share of imports does not change over time. As production of oil, gas and coal in Europe are not fully correlated with European demand this is a rough estimation. However, it is probably fair to say that investments in the oil, gas and coal supply chain will reduce with a reducing fossil fuel demand over the next 40 years. Investments in the value chain for biofuels and hydrogen infrastructure are assumed to increase with increasing demand. Altogether, this nets out in a decrease in capital spend over the next 40 years from € 1,900 billion for the baseline to € 1,400 billion in the decarbonized pathways.

Non-energy related capital is related to investments in energy efficiency measures in residential and commercial buildings and in industry, investments in CCS infrastructure for industrial applications (CCS infrastructure for power is included in the capital estimates for power) and investments in heat pump infrastructure. Capital that the automotive industry needs to spend to change to new drive trains (electric vehicles) is also included, as well as the additional cost of electric vehicle batteries, which could amount to about € 500 billion over the next 40 years, depending on the cost development of the batteries.

8.1.2 Full cost

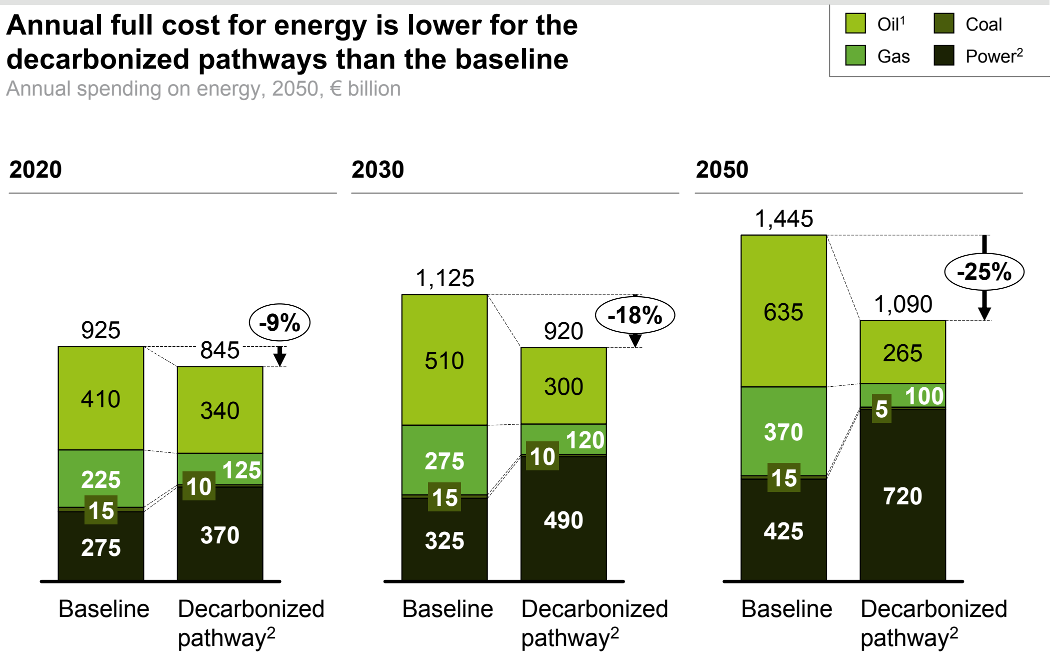
Final energy consumption is lower for the decarbonized pathways across the full energy system (aggregated demand for power, oil, gas, coal, etc.). This is driven by energy efficiency improvement in the power, transport, industry and buildings sectors, including gains due to the higher end-to-end conversion efficiency of heat pumps and EVs compared to what they are replacing. Furthermore, the decarbonized pathways use less oil, a relatively costly primary energy source.

As a result of these factors, the full cost of energy for the end-to-end energy system is lower in the decarbonized pathways. Exhibit 34 shows how in

EXHIBIT 34

Annual full cost for energy is lower for the decarbonized pathways than the baseline

Annual spending on energy, 2050, € billion



1 Includes biofuels and H2
2 Includes up to € 100 billion per year in 2050 to account for the additional capex from efficiency, EVs, heat pumps, industry CCS
3 60% RES / 20% CCS / 20% Nuclear pathway
SOURCE: IEA WEO 2009 (fossil fuel capex 2010-30, assumed constant 2030-50), McKinsey Global Cost curves, team analysis

2020, the advantage is about € 80 billion, increasing to € 350 billion per year in 2050. The full cost includes variable costs, fixed costs and amortization of capital cost. The cash cost benefit will be lower in the early years, as capital is spent upfront. If all benefits are in the end passed through to consumers, a benefit of € 350 billion per year by 2050 would equate to € 1,500 per year per household.

8.2 IMPACT ON DEPENDENCY ON FOSSIL FUELS

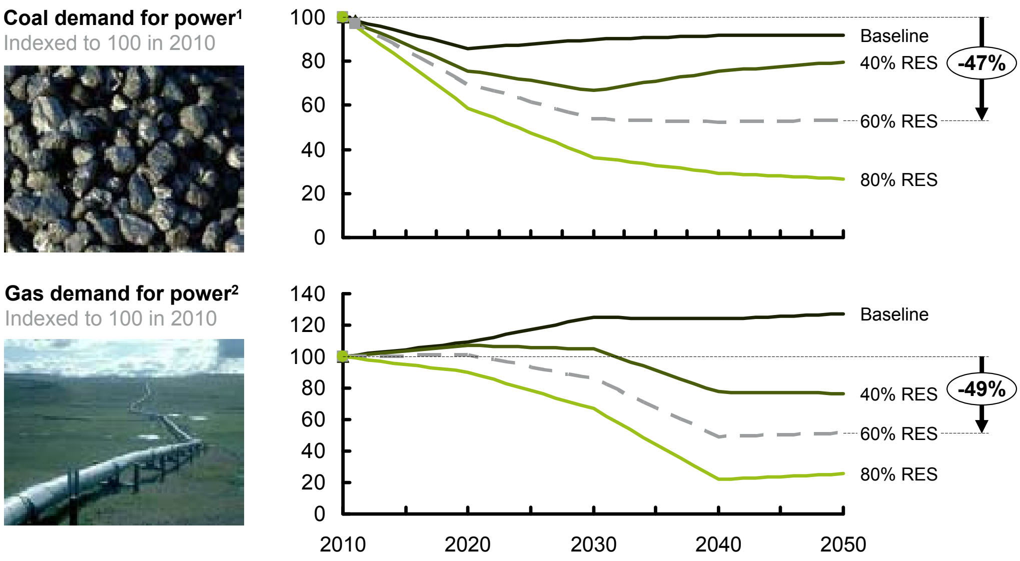
A lower dependency on fossil fuels has several potential benefits. Only the first of the following is discussed in this section:

- *More reliable energy sourcing*. Since imports of energy decrease, the EU's dependency on non-EU countries decreases as well. This effect increases with increasing RES penetration.
- *More predictable long-term fuel costs*. Less dependency on fuels whose costs are subject to potentially volatile global supply-and-demand dynamics will result in lower exposure to potential oil/gas/coal price spikes. Such price spikes have been strongly implicated in historic slowdowns of economic growth.
- *More sustainable energy use*. A system that is less dependent on fossil fuels is more resilient against resource depletion

Dependency on fossil fuels is lower in the decarbonized pathways compared to the baseline. As shown in Exhibit 35, the demand for coal for power generation reduces by 15% to 70% in 2050. Similarly, the power generation related gas demand reduces by 40% to 80%, both compared to the baseline. The ranges refer to the 40% RES and the 80% RES pathways. The pathways assume an even split of thermal generation between coal and gas. In reality the relative shares are likely to be different.

EXHIBIT 35

Coal and gas demand for power generation reduces significantly in the decarbonized pathways



1 Coal demand in the 40% RES pathway increases after 2030 due to: increasing coal share (1 percentage point) along with the increase in power demand
2 For CCGTs only, excluding requirements for back-up and balancing plants (OCGTs)

When including oil, gas and coal use for the building, transportation and industry sectors, a similar picture emerges. A rough estimate shows that the demand for oil and coal would reduce by about 60% and the demand for gas would reduce by about 70%, as shown in Exhibit 36.

It is unclear how the demand reductions in oil, coal and gas would affect imports to the EU. Oil supply from Europe will likely reduce both in the baseline as the decarbonized pathways, due to reserve depletion. Therefore it is not clear whether any oil demand reduction would translate in lower absolute oil imports. For coal, import dependency will also depend on the share of (typically locally mined) lignite. For gas, long-term imports would likely decrease in the pathways; short term, the balance could be different.

8.3 IMPACT ON MACRO ECONOMIC GROWTH

The direct effect of the decarbonized pathways on overall GDP growth is negligible, as GDP levels and growth rates are similar in the baseline and in the decarbonized pathways. Vulnerability to fuel prices will decrease. The European economy may emerge from the transition more competitive and resilient due to lower energy intensity and the diversification of its energy supply away from volatile priced fossil fuels. A potential upside from innovation spill-over effects depends on the likelihood that Europe builds and maintains an advantage over other regions for the next ten years or so. This may further increase productivity and GDP in the decarbonized pathways. History has shown that technology developments may have a sustainable positive *additional* impact of 0.5% to 1% on GDP.

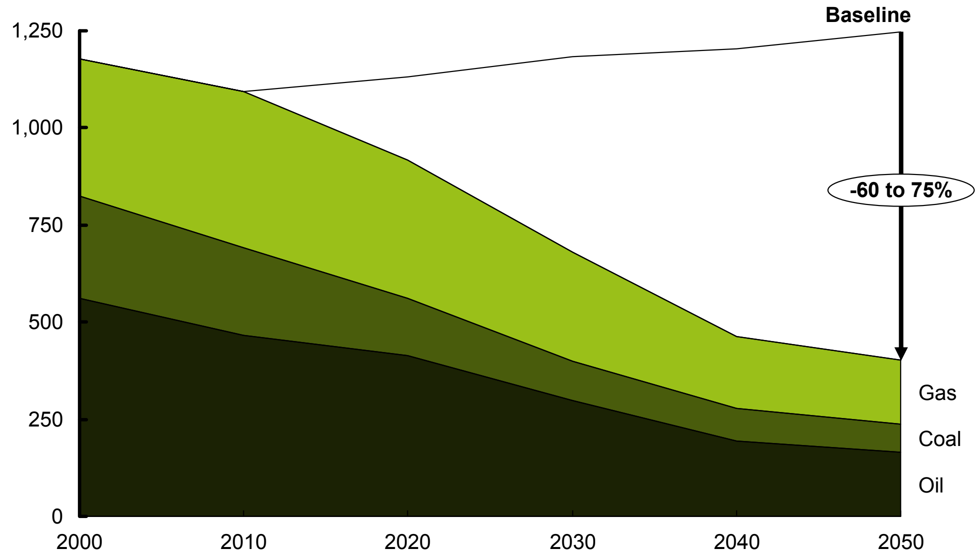
8.3.1 DIRECT MACRO-ECONOMIC IMPACT

GDP is assumed to more than double from € 10 trillion in 2010 to € 22 trillion in 2050, both in the baseline

EXHIBIT 36

Fossil fuels demand would reduce in the decarbonized pathways

Demand for fossil fuels across all demand sectors, Mtoe



SOURCE: McKinsey Global Cost curves, team analysis

and the decarbonized pathways. The difference in *annual growth rates* between the baseline and the decarbonized pathways is less than 0.05 percentage points a year. Annual GDP growth rates are 0.1% lower in the first years, resulting in a 0.5% lower GDP by 2015. This trend is reversed after 2015, ultimately resulting in a 2% higher GDP by 2050. Given the uncertainties in 40-year projections this difference is not significant. To give a sense of the small magnitude of such results, by 2015 it would take less than a month for the GDP in the pathways to catch up to the level observed in the baseline.

The decarbonized pathways could result in a higher productivity of the economy in the longer term. This is due to a relatively lower cost of energy per unit of GDP, due to additional energy efficiency improvements compared to the baseline and a shift from oil to (cheaper) power. Additionally, the impact of increasing carbon prices is lower in the decarbonized pathways emitting less. Energy cost per unit of GDP decreases in all scenarios, but more so in the pathways than in the baseline (see Exhibit 37).

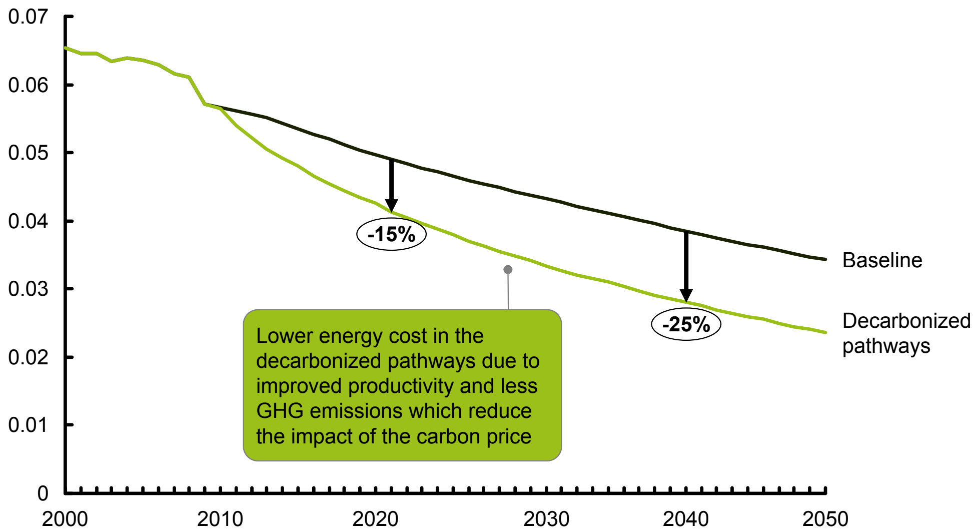
Sensitivity analyses show that a doubling of the fossil fuel prices depresses the GDP in the decarbonized pathways by 0.3 to 0.5% less than it would in the baseline across the 40 years, showing the benefits of a lower dependency on fossil fuels. If the cost of electricity in the decarbonized pathways were to turn out 25% higher than projected, GDP would be about 1% lower by 2050 than projected, as illustrated in Exhibit 38. This would basically bring the GDP of the decarbonized pathways to the same level as for the baseline. Every additional € 10 per MWh to the cost of electricity will cause a reduction in overall GDP of roughly 0.4% by 2050.

Early investment in low-carbon technologies, compared to other regions, could support European exports related to clean technologies in the next

EXHIBIT 37

Energy cost decreases in the baseline, but even more so in the decarbonized pathways

Energy cost per unit of GDP output, € (real terms)



Note: Energy prices are a weighted average of prices faced by consumers weighted by the shares of consumption of different fuels

decade. It is assumed that Europe builds and maintains a strong global position in clean tech and, importantly, that it sources the majority of the investments from European industries. In this case, European exports of clean tech will add as much as €250 billion to the GDP in the 2010-2020 period, assuming that it transforms to a low carbon economy faster than other regions. After 2020, Europe's lead is assumed to erode as other regions catch up.

The transition to a low-carbon economy makes the European economy more competitive and more resilient to CO_2 and fossil fuel price increases. With improved competitiveness due to an earlier start, sectors linked to the investment in low-carbon technologies and the clean tech exports could benefit.

Inadequate policies can have many detrimental effects, like limiting the penetration of energy efficiency improvements. For example, energy efficiency improvements in residential buildings depend on a complex mix of incentives and top-down regulations that are likely to prove difficult to implement. If inadequate policies would result in a doubling of the cost of implementation and a halving of the realization, the GDP loss could amount to €50 billion a year in 2020 and the erosion of most of the productivity benefits to the economy in the long-term, as illustrated in Exhibit 38.

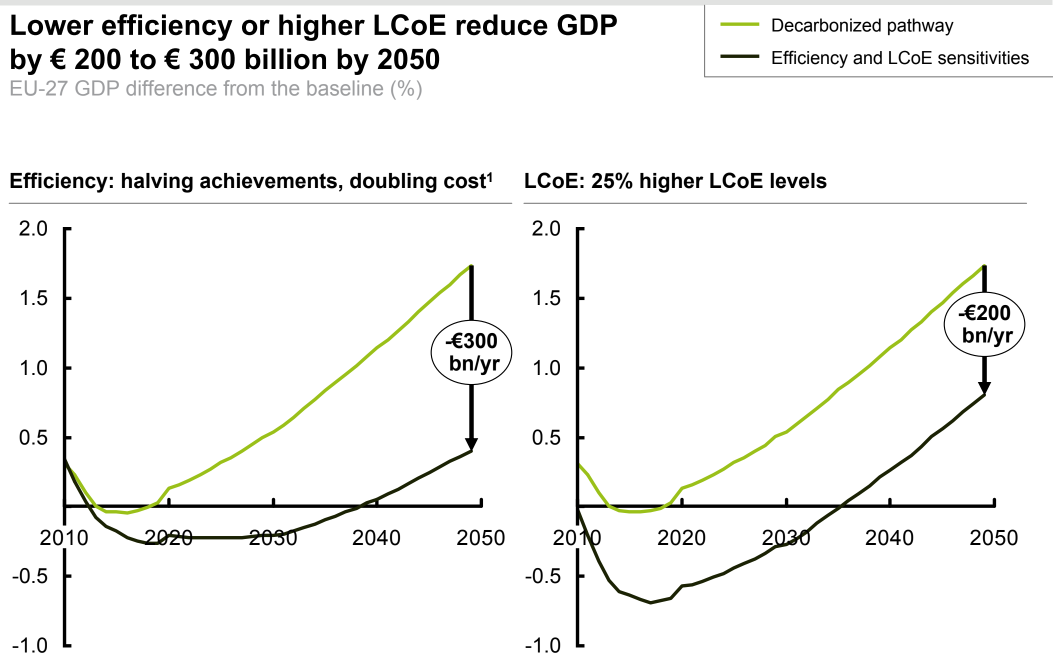
8.3.2 Indirect macro-economic effects

With a lower dependency on fossil fuels, Europe would be more resilient to economic crises triggered by a spike in oil prices. This effect will be enhanced if the rest of the world also moves away from fossil fuels, as economic downturns in other geographies strongly affect the European economy. A doubling in oil price for three years would depress the GDP

EXHIBIT 38

Lower efficiency or higher LCoE reduce GDP by € 200 to € 300 billion by 2050

EU-27 GDP difference from the baseline (%)



1 Doubling nominal cost of all efficiency improvements (industry, buildings and EVs); halving efficiency improvements in industry and buildings

in the baseline by an additional 0.5% compared to the decarbonized pathways, an effect of more than €300 billion. This effect alone is equal, for example, to about a third of the additional capital investment required over 40 years in the 60% RES pathway.

The industrial transformation implied by the decarbonized pathways has historical precedents that point to the potential for much greater positive economic impacts. The introduction of steam, the railroads, electricity and IT are examples of technological innovations that have led to dramatic productivity gains across the economy. Their contribution to GDP growth has been substantial, in the range of 0.2% to 1.9% per year. See Exhibit 39. Potentially, a transformation to clean technology and high penetration of efficiencies could lead to similar benefits. Past transformations suggest that there are benefits on three different levels:

- Increasing productivity in the innovating sectors themselves (for example, early stages of the IT revolution with continuous innovation in microprocessors). The equivalent for the clean tech transformation would be improvements in load factors of intermittent technologies, e.g., the marriage of spatial sensing technology with wind turbines to improve utilization rates in variable wind conditions

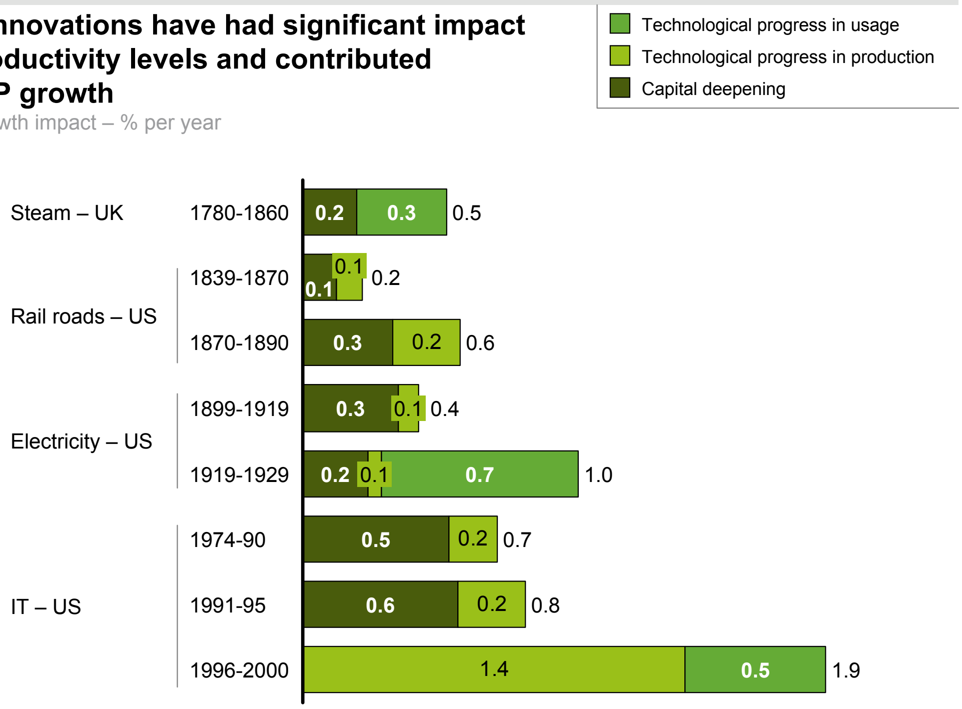
- Rapid reduction in cost of the technology and substantial investment in production (for example, quick expansion of computer manufacturing companies in the case of IT with the associated reduction in cost). The clean tech equivalent is increased efficiencies and reduced cost of electricity through mass deployment of PV equipment, e.g., through innovative integration of PV with conventional building components.

- Spillovers of productivity improvements in sectors that embed the new technology (for example, computerized manufacturing systems in the case of IT). Equivalent for the clean tech transformation

EXHIBIT 39

Past innovations have had significant impact on productivity levels and contributed to GDP growth

GDP growth impact – % per year



SOURCE: IMF, WEO 2001 (Chapter 3)

would be attracting energy intensive industries by providing low cost, decarbonized power. Examples could be a) investment in 'smart grids' that could change consumption and production choices and b) reduction in (the fluctuations of) electricity cost, freeing up resources for both households and companies

Some common characteristics of past innovations can serve as a guide to what we can expect from the quick and intense innovation in low-carbon technologies at the core of the pathways. First, most gains go to technology users rather than producers, as competition forces cost improvements to be passed on to consumers in the form of lower prices. Secondly, technology revolutions are often accompanied by periods of financial excess (railroad, electricity and IT all experienced financial bubbles as large amounts of capital were invested in the new technologies).

8.4 IMPACT ON JOBS

The transition has a limited net impact on overall employment, but differences across sectors are large, with sectors linked to clean technology benefitting most and energy intensive industries and fossil fuel energy suffering most. By 2050 the employment stock in the decarbonized pathways is 1.5% higher than in the baseline, while at its lowest it is 0.06% below the baseline (by 2020). Despite the small aggregate effect, the shift produces winners and losers. Sectors linked to the investment in low-carbon technologies and energy efficiency show higher employment in the pathway (such as construction, mechanical engineering, electrical engineering), while the fossil fuel energy sector and energy intensive industries suffer the most (such as iron and steel, metal precuts, coal, petroleum and gas).

In the decarbonized pathways the employment in renewable installations and in sectors related to decarbonization, especially those involved in energy efficiency measures and equipment manufacturing, would increase by 420,000 jobs. On the other hand, approximately 260,000 fewer jobs will be required in the traditional fossil fuels sector (such as coal, oil and gas installations) in the decarbonized pathways with respect to the baseline (see Exhibit 40). The macro-economic model indicates that some structural adjustment policies could be required in these and other sectors to manage the small short-term impact on employment of higher energy prices over the first decade.

8.5 IMPACT ON ENVIRONMENTAL SUSTAINABILITY

All of the decarbonized pathways show a marked increase in sustainability, primarily due to reduced emissions and improved management of finite resources. Nuclear waste production is similar in the 60% pathway to the baseline, in the 40% pathway it increases by 70%, while it decreases by 40% in the 80% pathway compared to the baseline. The required disposal facilities for both existing and potential newly produced waste have not yet been secured in most countries.

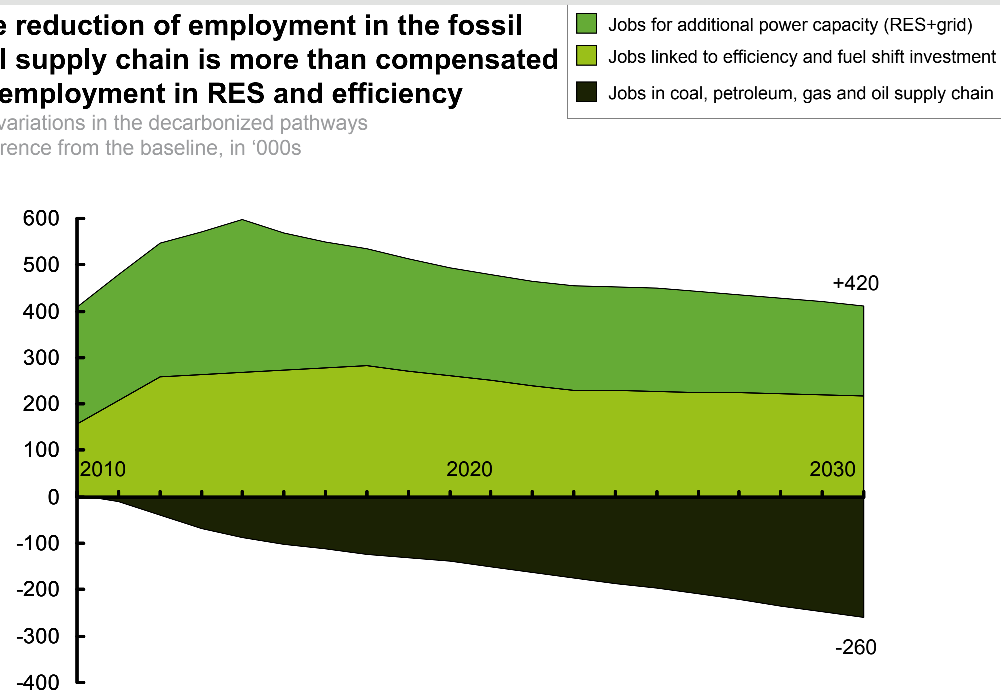
The difference in emissions between the pathways and the baseline is substantial. In the baseline 2050 GHG emissions for power are reduced by 10% below 1990 levels, while the reduction is 95% in the pathways. Economy-wide the reduction reaches 80%, with reductions happening regularly over time until 2050 as illustrated in Exhibit 41. While not quantified in this study, emissions of other known pollutants (such as black carbon, SOx, NOx, heavy metals) would also be lower in the pathways due to the reduced use of fossil fuels. The reduction of these non-CO_2 emissions is higher in the high-RES pathways. Other, non-emission related benefits (e.g., reduced noise levels through a switch to electric vehicles) have not been assessed.

EXHIBIT 40

The reduction of employment in the fossil fuel supply chain is more than compensated by employment in RES and efficiency

Job variations in the decarbonized pathways

Difference from the baseline, in '000s

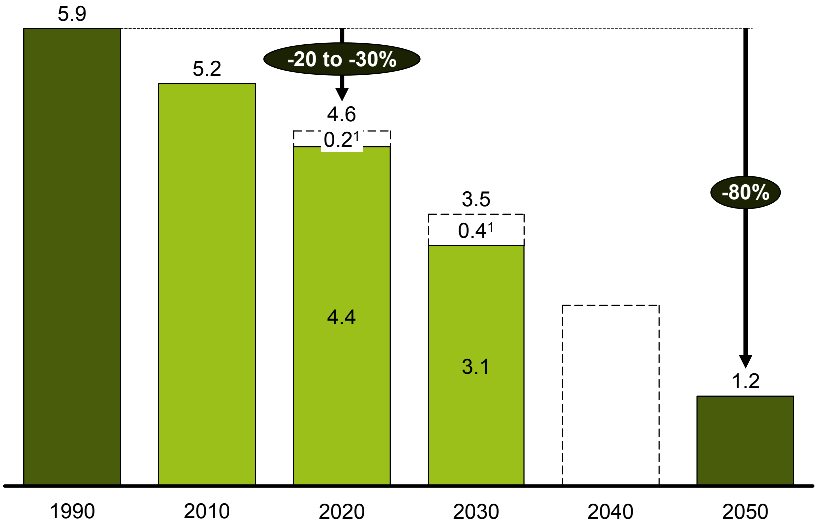


Note: Efficiency and fuel shift investment includes all efficiency levers from McKinsey cost curves (excluding what already in the baseline), further penetration of heat pumps in residential and industry and the slow penetration of EVs

EXHIBIT 41

To put the EU-27 on a path to 80% GHG reductions by 2050, a 20 to 30% reduction must be realized in 2020

EU-27 total GHG emissions in decarbonized pathway, $GtCO_2e$ per year



1 Timing of emission reductions depends on speed of implementation of abatement levers identified in the McKinsey Global GHG Abatement Cost Curve and the fuel shift towards CO_2-free electricity

SOURCE: McKinsey Global GHG Abatement Cost Curve; IEA WEO 2009; US EPA; EEA; Team analysis

8.6 DELIVERY RISKS

Both the pathways and the baseline have delivery risks associated with them. Some of these are similar between pathways, while some are more pronounced in some pathways. The overview below is not a complete overview but strives to highlight major potential delivery risks.

- **40% RES pathway**. In this pathway, nuclear and CCS play a large role. Therefore the technology risks (nuclear waste; maturation of new generation nuclear plants; proliferation; large scale CO_2 capture, transport and storage) and societal acceptance risks must be overcome. Fuel resource depletion may constrain this pathway in the long term (beyond 2050) and may cause spikes in the energy price in the shorter term

- **60% RES pathway.** This pathway relies on significant shares of nuclear, fossil+CCS and renewable technologies. Delivery risks described elsewhere for each technology applies, albeit in a lesser extent than in either the 40% or the 80% pathway

- **80% RES pathway.** This pathway is dominated by renewable technologies, predominantly wind and solar. Delivery risks include a) realizing the technology developments and cost learning rates, b) building up secure RES manufacturing supply chains c) resolving the intermittency issue in a cost effective way, like developing the required transmission and distribution grid capacity; and d) overcoming local opposition to wind (primarily onshore wind), transmission facilities (primarily overhead lines) and large scale solar (PV and CSP).

- **All pathways.** All the pathways require significant energy efficiency gains. If these would fail to materialize the power demand would be bigger, increasing the required capacity of the power system and thereby pushing up the total costs.

Second, clear and sustained political support will be necessary to a) increase collaboration between countries on developing, running and optimizing the entire energy system, b) developing effective permitting and licensing procedures, c) providing investments incentives both for generation and grid expansions and c) socializing the costs between countries. While this is required in each pathway, the level of integration required increases with increasing RES penetration. Third, public support for the transformation will be key – and not only in the power sector. Finally, all of the pathways rely upon a significant increase in the rate of capital investment in the sector; in the 60% and 80% RES pathways, the scale of the challenge is larger, while in the 40% pathway the major concern is with ongoing need for government support for investments in nuclear; but capital availability and cost is a common challenge across the pathways.

The magnitude and relative aversion to these risks will differ depending on the importance of different objectives (sustainability, security of supply, reliability, cost, capex) and will differ by stakeholder. The relative attractiveness of the pathways will differ by country, due to differences in, e.g., public acceptance, legacy infrastructure, available storage for CCS, etc. Exhibit 42 highlights some of these dimensions and gives the facts available based on this study. It does not attempt to give a rating to each of these dimensions or to compare them between each other, which is a societal and political choice.

EXHIBIT 42

Overview of the larger risk factors variations across pathways

Risk dimensions	40% RES, 30% nuclear, 30% CCS	60% RES, 20% nuclear, 20% CCS	80% RES, 10% nuclear, 10% CCS
Higher cost of generation ▪ Nuclear more expensive ▪ Lower CCS learning rate ▪ Lower RES learning rate	▪ CCS, nuclear capacity is 3 times that of the 80% pathway so these have the biggest impact		RES capacity is about three times that of the 40% pathways so lower learning rates have the biggest impact
Size of the transmission and back-up deployment required ▪ Interregional transmission ▪ Generation back-up capacity	**Capacity required, GW** ▪ 50 to 55 ▪ 75	▪ 85 to 100 ▪ 120	▪ 125 to 165 ▪ 155
Capital constraints ▪ Competing uses drive up cost ▪ Unavailability of capital for nuclear w/o govt support	Cumulative capital requirements, 2010-2050, € billion (share in total spent, capex + opex) ▪ 1,990 (24%)	▪ 2,550 (29%)	▪ 2,860 (33%)
Risk associated to nuclear development and production (e.g., security, waste)	Nuclear production, TWh, 2050 ▪ 1,470	▪ 980	▪ 490
Public acceptance risks	▪ Nuclear waste issue not solved ▪ CCS effectiveness and environmental risks not accepted	▪ "Energy nationalism" and NIMBY hampers interconnection and renewables policy harmonisation across Europe ▪ Biomass imports and related sustainability issues	
Risks associated with the build up of industries	▪ Nuclear/CCS industry cannot ramp up fast enough ▪ CCS storage capacity runs out	▪ RES industry cannot ramp up fast enough ▪ Smart grid roll-out and customer response slow ▪ No effective pricing mechanism installed to attract necessary investments	

CHAPTER 9
SHORT TERM IMPLICATIONS

Decarbonization of Europe's electricity sector – an essential step to achieving economy-wide abatement of at least 80% - is feasible without compromising system reliability; it is affordable under the assumptions used in this study and has no material impact on GDP. Electrification of transportation and efficiencies have a positive impact on energy cost per unit of GDP over the longer term. Investment in networks – both transmission and distribution – is the key to enabling a far wider range of affordable, reliable decarbonization options than most observers had previously thought possible. If the measures described in this report are implemented, CO_2 emissions can be reduced by at least 80% below 1990 levels by 2050.

Yet the change will not happen by itself. Therefore, the process of planning and implementation towards decarbonization needs to be continued or accelerated. If the objective of an 80-95% reduction in GHG emissions articulated by Heads of State in October 2009 is to be taken seriously, the imperative of a fully decarbonized power sector cannot be left to chance.

Different pathways lead to -80% emissions. A choice of which pathway Europe should ultimately follow may not be required, indeed may not be possible, for the next few years. This highlights the need to identify "no regrets" policy options in the near term, policies that ensure viable decarbonization options are not "locked out" and impediments to decarbonization are not "locked in." Many of these choices may be more relevant in the regions, as each region has different natural resources and different infrastructure legacies. Even within a region, the technology mix may remain unclear for some time, as the optimum mix will depend on implementation feasibility and cost developments. Yet it would be a serious mistake for the regions to proceed in an uncoordinated fashion; this study and others find that the cost to achieve even the currently mandated level of decarbonization, much less the more ambitious level contemplated here, would be far higher if pursued independently. Irrespective of the pathway, several short term common priorities across the different pathways can be identified:

- *Develop frameworks leading to EU-wide solutions, rather than country or technology specific solutions*. EU-wide solutions, e.g., stronger inter-regional grid planning and operations, will significantly lower the cost of decarbonizing electricity.

- *Focus on 5 critical short term implementation challenges*. Early success in energy efficiency; power decarbonization; preparing the ground for large-scale fuel shift; grid investments (transmission and distribution); and technology development are required to decarbonize the economy in 2050. Focus on no regret moves and avoid counter-effective measures

- *Ensure adequate incentives and funding for the required investments*. Investments in generation capacity and grid will not happen without incentives that provide healthy and reliable returns for investors. Current market mechanisms are inadequate for the capital intensity of the decarbonized electricity system; current grid regulatory frameworks are too fragmented, short-term and contingent to deliver the grid architecture that will be required.

- *Facilitate an entrepreneurial environment to drive change*. A flourishing business and research community that attracts talent and investors has proven to be a strong engine for change. Compare this to the clean tech investments in the US West Coast, or to the Chinese wind and solar industry, which has gained decisive momentum in the past several years. European entrepreneurs have multiple opportunities to capture clean tech opportunities, but this will require that that governments create policy frameworks that facilitate and reward clean tech entrepreneurship.

9.1 Develop EU-wide solutions

Coordinated investments in decarbonized generation technology are more cost effective than country-by-country decisions. Choices in local generation capacity investments, both on how much capacity is built and on the mix of intermittent resources, determines the optimum lay out of the inter regional grid and overall cost of electricity. If each country would make these choices in isolation, the technology mix would be non optimal, curtailment of renewable energy would be higher and the balancing solutions would be more expensive, e.g., requiring excessive local back up or storage capacity. Some recent studies, by neglecting the role that cross-border integration of electricity markets can play, have highlighted the disadvantages of "going it alone."

Currently, companies are required to support national renewable energy targets, but their optimum investments in renewable energy may lie in another country. Allowing more flexibility and differentiation over countries, and encouraging and ensuring the infrastructure necessary to take advantage of that diversity, could be more beneficial on an EU level. Processes and institutions, similar to Regional Transmission Operators in parts of the US, should be established to socialize burdens and benefits alike across the member states involved.

Decisions on using North African renewable energy like solar and wind have to be made in a European context, as the power inflow may have implications for countries beyond the Mediterranean countries. The same holds true for renewable energy imports from Russia and from other non EU regions.

A concrete immediate next step could be to follow up on this project by initiating several regional projects that use the approach and overall context to develop more specific conclusions for the respective region. Provided that these studies are managed in terms of consistency in approach, boundary conditions, deliverables and timing, these regional projects can be rolled out to provide an even more accurate view on the feasibility, costs and agenda for implementation for Europe.

9.2 Focus on five critical and urgent implementation challenges

Progress in five clean tech implementation programs is critical to ensure decarbonization by 2050.

9.2.1 Drive energy efficiency

The case for transition relies to a large extent on a marked improvement on the current pace of delivery of energy efficiency improvements across the economy. It is well established that vast potential exists for cost-effective energy efficiency measures, less costly than supply measures required to replace them. The costs of the proposed transition could rise significantly if implementation of energy efficiency measures falls behind. Innovative programs will be needed to eliminate information barriers, reduce transaction costs and mobilize investment capital.

If progress on energy efficiency programs fall behind, because implementation is challenging or the investments costs are too high, the demand for electricity will be higher than anticipated. While higher levels of consumption of decarbonized electricity is not in and of itself a barrier to an 80% economy-wide abatement, the costs for society will be higher, since more electricity is consumed and the marginal additional electricity supply may be more costly than the efficiency measures it would replace.

9.2.2 Make investments in low carbon power generation and supply chain

A massive and sustained mobilization of investment into commercial low-carbon technologies is needed, the vast majority of which will probably come from the private sector. Investors need greater certainty about future market conditions and the future competitive landscape. Current market design, i.e. energy markets based on marginal cost pricing, must be reviewed in light of the capital-intensity of these new technologies. Low-carbon investors need more clarity about the ultimate fate of high-carbon assets, to have sufficient confidence that their investments will be profitable under a sufficiently wide range of future market conditions.

Furthermore, investment in oil, coal and gas supply chains need to be considered against the 2050 pathways. Gas, coal and oil infrastructure will remain critical for the next decades and potentially beyond 2050, but the scale and lay out may be different, e.g., the future gas infrastructure may be required to provide significant short-term back up services. The refining infrastructure may be focused relatively more on jet fuel, bunker fuels and chemical feed stocks.

9.2.3 Pave the way for large-scale fuel shift

Without fuel shift in the transport and building sector, the -80% target will not be achieved. Fuel shift in transport has started through biofuels blending. A larger shift is expected to electrification of cars and potentially hydrogen fuel cell vehicles. While this larger shift will become significant only in the longer term, electrification urgently requires piloting and development of standards for charging infrastructure (including critical information and control technologies), and hydrogen requires greater clarity on supply and delivery options; both require cost reductions through technology developments and stronger regulation in the form of steadily and aggressively tightening emissions standards for road transport. In buildings, a ramp-up in the application of heat pumps (both in individual premises and in district heating applications), along with biomass district heating or the capture of industry waste heat, should be designed into any future energy efficiency implementation plans. Roll-out should begin selectively in new construction to develop the manufacturing, supply and installation infrastructure that will be needed later for more wide-spread application. Electrification in transport and buildings has no positive abatement effect, of course, unless electricity is decarbonized.

9.2.4 Develop critical low carbon technologies

The case presented here does not rely on technology breakthroughs, but it does rely on steady, in some cases dramatic improvements in existing technologies. Coordination of support for development and deployment of, e.g., energy efficiency technologies, CCS (also for gas), PV, offshore wind, biomass, electric vehicles, integrated heat pump and thermal storage systems, smart grids that allow demand response (DR), and networked HVDC technologies, including adoption of common standards, will be critical. R&D support for, e.g., enhanced geothermal systems, large-scale storage and other new, potential breakthrough technologies will enable the transition to happen faster and at lower cost than presented here. If technology developments fall behind expectations, the cost for the transition will be higher.

9.2.5 Expand the grid, integrate market operations

A large increase in the interconnectedness of European regional electricity markets is a key to the transition in all pathways; it is, paradoxically, also the key to reliable and economic integration of localized energy production, along with investments in smarter control of demand and decentralized supply. As shown in section 5.3.3, even for the level of decarbonization mandated between now and 2020 (effectively the 40% RES pathway), addressing the system integration issues on a country-by-country basis, rather than through regionally integrated processes, will drive up costs (e.g., solving it without sharing could require 70% more reserve). Effective transmission and distribution regulation, the development of regionally integrated approaches to planning and operation of grids and markets, and support from stakeholders are required. Current mandates to ENTSO-E and ACER should be reviewed to ensure that they have the proper authority and responsibility to coordinate these efforts, as it will be critical that they do so.

9.3 ENSURE ADEQUATE INVESTMENT INCENTIVES

A massive and sustained mobilization of investment into commercial low-carbon technologies is needed, the vast majority of which will probably come from the private sector. Investors need greater certainty about future market conditions, and about the future competitive landscape. Current market design, e.g., energy markets based on marginal cost pricing, must be reviewed to address the capital-intensity of these new technologies. Low-carbon investors need more clarity about the ultimate fate of current and planned high-carbon assets, to have confidence that their investments will be profitable under a sufficiently wide range of future market conditions.

Sufficient funding needs to be made available against attractive conditions. The decarbonized pathways require significant additional capital, as well as large shifts from one sector to the other, e.g., less fossil fuel supply chain investments and more clean-tech investments.

9.4 FACILITATE CLEAN TECH ENTREPRENEURIALISM

Policy makers can facilitate investments by entrepreneurs in clean tech initiatives. This would require various modes of support for emergent products and services (regulation, subsidies, assured markets) and coordinating facilities (e.g., attracting talent, linking with academia).

A partial list of potential opportunities that could become significant business opportunities in the next 5 years include:

- Commercialization of new technologies, e.g., geothermal and ground-source energy – some greenhouse gas entrepreneurs are acquiring concessions to use ground-source and shallow geothermal energy for greenhouse heating. Can also be used for district heating.
- Develop commercial-scale biomass fuel supply chain businesses in Europe, including import hubs as well as cultivation, harvesting and processing of the biomass
- Development of hydrogen infrastructure for fleets, e.g., buses or transport and logistics companies to move their fleet to near zero carbon. Hydrogen can be produced without CO_2 emissions, e.g., when using an IGCC CCS demo plant, SMR on biogas or bio-ethanol, electrolysis through renewable power, etc. (piggy back on Germany Hydrogen Mobility investment)
- Development of technology, manufacturing or installation business for heat pumps in buildings (already a growing industry in Japan)
- Manufacturing and marketing of 2-wheelers and small cars on electric power (already an established business in China).
- Building or converting CHP in industrial areas to biomass. Realize energy efficiency gains, renewable targets and CO_2 reductions. Capture CO_2 price benefit for industries under ETS.

GLOSSARY

Abatement cost curve	Compilation of abatement potentials and costs
Abatement lever	Technological approach to reducing greenhouse gas emissions, e.g., use of more efficient processes or materials
Abatement potential	Technical potential for reducing greenhouse gas emissions by implementing an abatement lever, only limited by technical constraints (e.g., maximum industry capacity build-up).
Baseline	Baseline scenario to which the various pathways are compared to. Based primarily on external forecasts, e.g., IEA and Oxford Economics projections.
Battery electric vehicle	Battery electric vehicles use rechargeable plug-in batteries as its only source of power
Capex	Capital Expenditures (investment)
CCS	Carbon Capture and Storage – technologies for capturing and storing GHGs, mostly underground
CDM (projects)	Clean Development Mechanism – mechanism in the framework of the Kyoto Protocol that gives emitters of signatory states the option of investing in projects in developing countries under specified conditions and receiving CO_2 certificates for this
Centre of gravity	The centre of gravity is the geographical centre of a region. It is used as the point to and from which the regional demand and generation is connected (either directly or for offshore wind via transmission capacity to the shoreline) and where all inter-regional flows start and terminate
CHP	Combined Heat and Power (plant), systems which deliver both heat and produce electricity
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent is the unit for emissions that, for a given mixture and amount of greenhouse gas, represents the amount of CO_2 that would have the same global warming potential (GWP) when measured over a specified timescale (generally, 100 years).
COP	The Coefficient Of Performance of a heat pump describes the amount of heat produced per kWh of electricity used by the heat pump. A COP of 4 effectively means that the heat pump produces 4 kWh of heat source for every kWh of electricity used.
’Demand Response’ (DR)	Demand response refers to a change up or down in a customer’s electricity demand in response to dispatch instructions or price signals communicated to customers’ premises; DR as used here does not reduce the energy delivered in a day, it time-shifts it within the day.
Dispatchable	“Dispatch” refers to instructions to resources issued automatically or by system operators. “Dispatchability” refers to the ability of a resource to respond to specific instructions to operate in a given mode at a given point in time with a high degree of reliability

EU ETS	Emissions Trading Scheme of the European Union
EUR or €	Real 2010 Euro
EV	(Battery) Electric Vehicle
Firm Capacity	Firm capacity refers to a system resource that can be expected to be available to meet load on command with a very high degree of reliability. Each resource on a system receives firm capacity credit depending on the amount of the resource's rated capacity that statistically satisfies the agreed standard
Greenhouse gas (GHG)	Greenhouse gas in the context of the Kyoto Protocol, i.e., CO_2 (carbon dioxide), CH_4 (methane), N_2O (nitrous oxide), HFC/PFC (hydrofluorocarbons), and SF_6 (sulfur hexafluoride)
Gt	Gigatonne(s), i.e., one billion (10^9) metric tonnes
HDV	Heavy duty vehicle
Heat pumps	Heat pumps use electric power to move heat from one location to another for heating or cooling purposes. Their efficiency is described by their Coefficient of performance (see COP)
Hybrid vehicle	Hybrid vehicles use an internal combustion engine (ICE) as primary mover, but also electric power that supplements ICE power
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle – combined gas and steam turbine system with coal gasification system
Intermittent resource	Intermittency refers to the fact that a resource's availability to produce is driven by uncontrollable and unpredictable availability of it's primary energy supply (e.g., wind or solar energy) rather than by the specific time- and load-bound demands of the system. There are degrees of intermittency – for instance some resources may be somewhat predictable over important time horizons such as day-ahead but unpredictable over longer but equally important planning horizons – however the fact of intermittency defines a certain category of resources, e.g., wind, solar PV and run-of-river hydro. Some actors prefer the term "variable" to describe certain of these resources, however in practice this is largely a distinction without a difference
kWh	Kilowatt hour(s)
LDV	Light duty vehicle
MDV	Medium duty vehicle
Mt	Megatonne(s), i.e., one million (1,000,000) metric tonnes
MWh	Megawatt hour(s), i.e., one million Watt hours
OCGT	Open Cycle Gas Turbine
Opex	Operating expenditure. When used referring to cost of electricity, it is the operational costs required for the production of electricity, including fuel costs, operational and maintenance cost and savings (e.g., from reduced energy consumption)

PHEV	Plug-in Hybrids Electric Vehicle. These use power from both an ICE and a battery that can be plugged in to charge
Response	Response provides an instantaneous reaction to a change in load or generation (e.g., due to a failure) managing second by second variations.
Reserve	Reserve will be used when other capacity cannot provide the output as scheduled, e.g., due to failure or because the primary energy, e.g., wind, is not available; reserves fall into various categories based on the time within which the reserve must be able to respond (e.g., milliseconds to minutes to months)
Sector	Grouping of businesses or areas emitting GHGs, specifically: **Power:** Emissions from power and heat generation, including for local and district heating networks **Industry:** Direct emissions of all industrial branches with the exception of power generation and the transportation sector. Indirect emissions are accounted for in the power sector **Buildings:** Direct emissions from private households and the tertiary sector (commercial, public buildings, buildings used in agriculture). Indirect emissions are accounted for in the power sector **Transport:** Emissions from *road transport* (passenger transportation, freight transportation and buses), as well as sea and *air transport* **Waste**: Emissions from disposal and treatment of waste and sewage **Agriculture:** Emissions from livestock farming and soil management
t	Metric tonne(s)
TWh	Terawatt-hour(s), i.e., one trillion (10^{12}) Wh
USD or $	Real 2010 US Dollars
Utilization	Utilization of transmission line is the percentage of time the maximum capacity is used. It is the total energy (MWh) that flows, divided by the maximum capacity (MW) times the number of hour in the year (hours)

APPENDICES AVAILABLE ONLINE

A. Technical assumptions on generation

B. Detailed grid methodology

C. Transmission costing assumptions

D. Incremental transmission capacity requirements between regions in all pathways

E. Distribution network modeling

F. Detailed Macro modelling assumptions

ROADMAP 2050

A PRACTICAL GUIDE TO A PROSPEROUS, LOW-CARBON EUROPE