Power Perspectives 2030

On the road to a decarbonised power sector

A contributing study to Roadmap 2050: a practical guide to a prosperous, low-carbon europe

PREFACE

At the G8 in July 2009, the leaders of the European Union announced their objective to reduce domestic greenhouse gas emissions by at least 80% below 1990 levels by 2050. In October 2009 the European Council set that abatement target in stone for Europe. In support of this objective, the European Climate Foundation (ECF) initiated a study to establish a fact base for this goal and to derive the implications for European industry and in particular for the electricity sector. The result was *Roadmap 2050: a practical guide to a prosperous, low-carbon Europe*[1], published in April 2010. It showed that the transition to a fully reliable, fully decarbonised power sector by 2050 is a pre-condition for achieving the 80% economy-wide emissions reduction target, and that this transition is technically feasible and economically affordable. The project showed that implementation of certain measures such as grid build-out, renewable energy and CCS deployment and increased energy efficiency are critical levers in managing the transition to a decarbonised power sector.

Since then, European policy makers have made a number of steps towards realizing these long-term objectives. On 4 February 2011, the European Council, at a special energy and innovation summit, repeated its commitment to achieve the long-term targets of 80–95% domestic GHG reductions and recognized that this means nothing less than "*a revolution in our energy systems, […], which must start now*"[2]. One month later, on 8th March 2011, the European Commission expanded on these words in its communication "*A roadmap for moving to a competitive low carbon economy in 2050*"[3]. The Commission's analysis confirms the central role that electricity plays in the decarbonisation of other sectors such as transport, industry and buildings, and indicates that power itself "*can almost totally eliminate CO_2 emissions by 2050*". Hence, the European Commission called for a secure, competitive and fully decarbonised power sector by 2050. In that document, the Commission also set out sectoral GHG reductions with a mid-term view on 2030 to manage the decarbonisation of the economy in the most cost-effective way. For the power sector, the Commission set a carbon dioxide (CO_2) reduction range of between 54% and 68% by 2030 compared to 1990 levels. Later this year, the Commission will follow up with a specific energy roadmap that analyses pathways based on this trajectory towards 2030 and 2050, while ensuring energy security and competitiveness.

1 This report is further reference as *Roadmap 2050.* Details and results can be found at www.roadmap2050.eu
2 Special European Heads of State Summit on Innovation and Energy, 4 February 2011 http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/119175.pdf
3 European Commission Communication SEC 2011 (211), A roadmap for moving to a competitive low carbon economy in 2050 http://ec.europa.eu/clima/documentation/roadmap/docs/com_2011_112_en.pdf

Table 1: Sectoral GHG reductions[4]

GHG reductions compared to 1990	2005	2030	2050
Total	-7%	-40 to -44%	-79 to -82%
Sectors			
Power (CO_2)	-7%	**-54 to -68%**	-93 to -99%
Industry (CO_2)	-20%	-34 to -40%	-83 to -87%
Transport (incl. CO_2 aviation, excl. maritime)	+30%	+20 to -9%	-54 to -67%
Residential and services (CO_2)	-12%	-37 to -53%	-88 to -91%
Agriculture (non-CO_2)	-20%	-36 to -37%	-42 to -49 %
Other non-CO_2 emissions	-30%	-72 to -73%	-70 to -78%

It is within this new policy framework that ECF decided to embark on a follow-up study, called *Power Perspectives 2030: on the road to a decarbonised power sector*[5], to provide a view on the progress necessary by 2030 to remain on track to a fully decarbonised power sector by 2050.

Power Perspective 2030 is a technical assessment of the challenges related to the decarbonisation transition. The report is designed to bring qualitative and quantitative insight into the role of key power sector elements (supply – transmission – demand) in keeping a system in transition robust and balanced. The study's context and methodology are presented in Chapter I. In Chapter II, the report looks at the challenges and solutions of balancing a changing power system. In Chapter III, the report also provides a perspective on the implications for power markets in Europe.

Building on this report, the ECF strongly recommends that further work be carried out to help stakeholders to understand the required transition in more detail, including the different ways in which various regions would implement and steer the transition.

4 European Commission Communication SEC 2011 (211), A roadmap for moving to a competitive low carbon economy in 2050 - http://ec.europa.eu/clima/documentation/roadmap/docs/com_2011_112_en.pdf

5 Further referred to as: *Power Perspectives 2030*

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ACKNOWLEDGMENTS

Power Perspectives 2030: on the road to a decarbonised power sector breaks new ground by clearly describing the challenges and potential solutions facing us in the transition to a fully decarbonised power sector from a broad European perspective, while ensuring energy security and competitiveness. The report is based on the best available facts as contributed by industry players, non-governmental organisations (NGOs) and academia, and developed by a team of recognized experts.

Power Perspectives 2030 is a contribution to the European Climate Foundation's (ECF) *Roadmap 2050: a practical guide to a prosperous low carbon Europe*, published in April 2010[6], and was carried out by the same consortium of experts including KEMA; The Energy Future Lab at Imperial College London; the Regulatory Assistance Project (RAP), E3G, the Energy Strategy Centre and The European Climate Fondation. In addition, a wide range of companies, transmission system operators, technology manufacturers, consultancy firms, research centres and NGOs have provided various forms of assistance during the preparation of the report, which started in February this year. These organisations have provided valuable counsel that has been faithfully reflected in this analysis. Their willingness to consult and to be consulted in the course of this work should not be understood as agreement with all of its assumptions or conclusions.

The ECF wishes to thank the members of the core reflection group for participating to the bi-monthly meetings and for having provided feedback throughout the development of *Power Perspectives 2030.* These are: utilities, technology manufactures and energy companies, EdP, Dansk Energi, Dong Energy, GdF Suez, Siemens, Shell, Vattenfall, Vestas and RWE; the transmission system operators, Energinet.dk, Elia, Nationalgrid, Red Electrica Espagnola and Tennet; and NGOs, E3G (Third Generation Environmentalism), WWF (European Policy Office). Enel has been participating to the project as observer.

The report is funded jointly by ECF, which itself is funded solely from private philanthropic organizations[7], and most of the companies in the core reflection group[8]. ECF remains the main contributor and stakeholder in the project and is responsible for final decisions on the scope and the results of the study[9]. ECF does not have financial ties to EU political bodies or to businesses.

Representatives of the European Commission, notably from Directorate-General for Energy, have provided strong encouragement for the development of this undertaking and have given welcome guidance regarding the objectives and the approach throughout the project.

6 For more details on ECF's Roadmap 2050 report, please see: www.roadmap2050.eu
7 ECF's funding sources are fully disclosed on its website, www.europeanclimate.org
8 Contributing organisations are: Dansk Energi, Dong Energy, EdP, Enel, GdF Suez, RWE, Shell, Siemens, Vattenfall and Vestas
9 ECF has acted as a neutral convener of the project. Dries Acke, ECF, has acted as overall project manager of the report.

EXECUTIVE SUMMARY

A. CONTEXT

In October 2009, the European Council set an economy-wide greenhouse gas (GHG) abatement objective of 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 for achieving this goal and to derive the implications for European industry and in particular for the power sector. The result was *Roadmap 2050: a practical guide to a prosperous, low carbon Europe*, published in April 2010. It showed that the transition to a fully reliable, fully decarbonised power sector by 2050 is a pre-condition for achieving the 80% economy-wide emissions reduction targed. The study also established that full power sector decarbonisation is technically feasible and economically affordable.

On March 8, 2011, the European Commission confirmed this conclusion when it published "*A roadmap for moving to a competitive low carbon economy in 2050*". In that document, the Commission set out sectoral carbon dioxide (CO_2) reduction trajectories with a mid-term view on 2030 to steer the decarbonisation of the economy on a manageable and cost-effective course. For the power sector, the Commission proposed a CO_2 reduction range of between 54% and 68% by 2030 compared to 1990 levels. Later this year, the Commission will follow up with a specific energy roadmap that analyses pathways based on this trajectory towards 2030 and the 80-95% reduction by 2050, while improving energy security and competitiveness.

It is in the context of these new policy developments that the ECF decided to embark on a new study, *Power Perspectives 2030: on the road to a decarbonised power sector.*
This study provides a view on the progress that is necessary by 2030, creating a way-point by which to navigate the path to a fully decarbonised power sector by 2050.

Power Perspectives 2030 finds that existing plans for renewables, and transmission grids up to 2020, if fully implemented, constitute an adequate first step to decarbonisation but that the transition needs to accelerate towards 2030 in order to remain on track to the 2050 CO_2 abatement goal for the power sector. This acceleration implies a near doubling of investments in low-carbon generation and a near doubling of electricity grid capacity in the decade after 2020. Hence, in the current decade, the European Union, its Member States and the relevant commercial undertakings need both to ensure the implementation of current commitments and to establish an adequate policy and legal framework to steer the decarbonisation of the power sector beyond 2020.

B. OBJECTIVE

The ambition of *Power Perspectives 2030* is to analyse what is required between today and 2030 to remain on a secure pathway to a decarbonised power sector by 2050. It attempts to identify the challenges and solutions based on today's knowledge of the options. Last year's *Roadmap 2050* report showed that the transformation to a decarbonised and secure power sector is technically feasible at similar overall cost to a non-decarbonised power mix, due to a major shift from operational costs ("opex") to capital investments ("capex"). An increase in upfront investments is recouped over time by substantial reductions in operating costs. While last year's report significantly increased confidence in the feasibility of the 2050 end-goal, it also hinted at the challenges Europe will face in implementation. *Power Perspectives 2030* now brings more detailed insight into these challenges and the solutions at hand to remain on track towards full decarbonisation by 2050.

C. APPROACH

Power Perspectives 2030 focuses on the transition between today and 2030 and closely follows the sectoral emissions trajectory set out by the European Commission's March 8, 2011 communication, which indicates a CO_2 emissions reduction range of around 60% for the power sector in 2030.

From a methodological point of view, the analysis first defines the demand and production mix as an input to determine the hourly demand and production curves, and then defines transmission and back-up capacity required to meet demand at optimal cost and at current levels of system reliability. The modelling applies the following conditions: achieving the EC's 2030 CO_2 emission reduction range, maintaining power supply reliability at current levels and, where possible, avoiding early retirement of existing assets. Import/export of power for each country is limited in 2020, as each country is expected to be more or less self-sufficient (with a few exceptions). In 2030 more import/export is allowed but self-sufficiency is preserved despite the increase in RES capacity for almost all countries.

The report compares the results from various sensitivity scenarios against the central scenario to bring qualitative and quantitative insight into the effects of changing specific elements of the power system (supply – transmission – demand). This central scenario is called the *On Track case.* Up to 2020, it is based on the full implementation of the existing plans for the power sector[10]. Towards 2030, it models a power system in line with the EC's emission reduction goals with a production mix with 50% renewable energy sources[11] (12% wind on-shore, 10% wind off-shore, 6% solar PV, 10% biomass, 11% hydropower and 1% geothermal), 34% fossil fuels (28% gas, 6% coal) and 16% nuclear across Europe. This differs from a *Business-as-Usual case* where the current plans and targets up to 2020 are not implemented and the CO_2 reduction range for the power sector in 2030 is missed by half [12].

D. STAYING ON TRACK TO DECARBONISATION

1. THE COST OF DECARBONISATION REMAINS WITHIN SIMILAR RANGES OVER THE DECADES, BUT A SHIFT FROM COST (OPEX) TO INVESTMENTS (CAPEX) NEEDS TO BE PURSUED

The analysis shows that it is possible to remain on track to decarbonisation towards 2030 at a levelised cost of electricity (LCOE)[13] for new builds similar to the LCOE in this decade. The analysis shows LCOE numbers of €89/MWh in 2020 and €85/MWh in 2030 for new builds, including CO_2 prices, which is only a small increase compared to the estimated value of €82/MWh for new generation added in the previous decade[14]. These estimates are comparable to the numbers in last year's *Roadmap 2050* report which showed a backcasted LCOE of €84/MWh in 2020 and €86/MWh in 2030[15]. The analysis thus shows it is feasible to keep LCOE under control through the decades of transition to a fully decarbonised power sector. The increase in upfront investments will have to be incentivised appropriately but will pay–off through decreasing operating costs.

2. EXISTING POWER SECTOR PLANS AND TARGETS ARE ADEQUATE TO BALANCE THE POWER SYSTEM UP TO 2020, BUT SIGNIFICANT IMPLEMENTATION CHALLENGES REMAIN

The analysis shows that current power generation and grid plans are adequate to balance the planned power mix in 2020[16]. Still, it is clear that full implementation of these plans requires substantial effort, particularly by

10 These plans are: the National Renewable Action plans (NREAPs) and the Ten-Year National Development Plans from ENTSO-E (TYNDP).
11 Renewable energy sources cover a diverse portfolio of commercial technologies with very different charachteristics. This diversification of resources is important for the security and reliability of electricity supply
12 This scenario is well described in the European Commission's PRIMES report "EU trends to 2030 - baseline", (update 2009). This leads to an emissions reduction of 13% in 2020 and 31% in 2030.
13 "Levelized cost of electricity" is an expression of the total cost of a product including both current outlays for operations and a charge each period to repay the initial capital investment.
14 This is an estimation of the average LCOE in the decade 2000 – 2010, based on costs estimated in IEA WEO 2009 and in Nuclear Energy Agency reports published in June 2010. The LCOE per technology is based on latest information from Eurelectric
15 There are a few differences in approach between *Roadmap 2050* and *Power Perspective 2030* in this regard, such as more conservative assumptions on load factors and higher granularity in grid modelling then in "Power Perspectives 2030"
16 RES curtailment on average remains very low, around 0,6% in 2020. For more details see exhibit 10 in the full report.

Member States. For example, Europe's transmission system operators (ENTSO-E) have a ten-year network development plan requiring an increase in transmission lines of 64 GW from 2010 to 2020 - a 30% capacity increase over the existing network. Similarly challenging are the implementation of the National Renewable Energy Action Plans (NREAPs) through which Member States expect to comply with the 20% target in the binding Renewables Directive. Challenges also remain in achieving the 2020 energy savings target, where European leaders have indicated that so far only about half of the desired energy productivity gains are set to being realised[17].

As recognised be European Energy Ministers earlier this year[18], major investments will be needed for new low-carbon generation up to 2020. The analysis for the *On Track case* confirms the EC investment estimates and shows that around €628 billion (of which €567 billion for generation, €15 billion for back-up capacity and €46 billion for transmission expansion) needs to be mobilized in the period from 2010 to 2020. The numbers indicate that the challenge of attracting investments lies primarily with low-carbon generation technologies, and less with back-up or transmission expansion.

3. KEY CHALLENGES ON THE ROAD TO DECARBONISATION

3.1. TRANSMISSION GRID

Significant new grid capacity is required beyond 2020. Additional investments in transmission grids, including off-shore wind connections, of €68 billion for the *On Track case* are projected from 2020 to 2030 to enable the construction of around 109 GW of additional transmission capacity – a 50% increase from the planned network in 2020 and a near doubling of today's existing capacity. Most of the additional interconnections are projected across borders (between southern UK and Ireland (13 GW), between southwestern France and northeastern Spain (9 GW)), but large transmission upgrades are also required within countries (northwestern to western Germany (10 GW), northern to southern UK (8 GW))[19].

Grid build-out risks being slowed down by several factors, e.g. delayed planning or consenting procedures and a lack of clarity regarding the cost allocation of interconnectors among participating countries and transmission operators. The current system relies on investors building interconnectors on a merchant basis or on ad hoc bilateral arrangements between member states driven by the economic rents that underpin merchant transmission[20]. However, the basic economics of merchant interconnectors make it very unlikely that this will lead to the level of required investment identified in our analysis.

Upgrading the grid infrastructure is, however, the most cost–effective way to keep a power system in transition secure and reliable. Less transmission build-out will lead to less optimal use of RES and additional need for back-up capacity[21]. Sensitivity scenarios with a 50% reduction in transmission capacity when compared to the *On Track case* show more volatile prices, higher curtailment levels, and an increase in back-up capacity required in 2030 leading to slightly higher emissions in 2030. When applying an even higher share of diverse RES (60% in 2030), the effects of insufficient transmission build-out increase exponentially. Hence, transmission expansion throughout Europe is a fundamental enabler for integrating power markets and is the most cost effective means to accommodate higher levels of diverse RES in a secure and robust power system.

17 Special European Heads of State Summit on Energy and Innovation on 4th February 2011.
18 European TTE Council, February 28th 2011 – http://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/trans/119518.pdf
19 Sensitivity analyses demonstrate that the 2030 emission reduction range is also achievable with lower levels of investment in new transmission. However in all cases this leads to increases in cost and price volatility. We did not test specifically the impact of a larger role for distributed generation but the analysis provides strong indication that a more distributed solution has minimal impact on the scale of the optimal transmission expansion, though the architecture of the expansion could be expected to be somewhat different.
20 It is acknowledged that the European Commission has in October 2011 tabled legislative proposals that address these issues.
21 If further developments in battery storage technologies materialise and solutions become cost-effective alternatives, they can play an important role in optimising system balancing in combination with transmission and back-up.

3.2. LOW-CARBON GENERATION TECHNOLOGY

Power Perspectives 2030 shows that diversification and decarbonisation can go hand in hand both up to 2020 and beyond, and is driven by a continuation of the deployment of a portfolio of promising RES technologies. This is essential to a well-diversified, no-regrets decarbonisation trajectory for the power sector. To support the deployment of these low-carbon technologies, more upfront investment (capex) in generation capacity is required. In the *On Track case*, €1,153 billion capital expenditure (of which €1,028 billion for generation, €57 billion for back-up and €68 billion for transmission expansion) is needed in the period from 2020 to 2030[22]. That is a near doubling of the estimated investments required in the period from 2010 to 2020, bringing the total capex for the next two decades together to €1,781 billion, representing 0.5% of EU-27 GDP (based on 2010 GDP) per year for the 2010-2020 period. This is a significant challenge and may require adaptations to the power markets or other measures to stimulate investments. There is a growing consensus within the financial community that, alongside existing approaches, new models will need to be found to finance this transition[23]. Interestingly, a 2030 power mix with even higher shares of diverse RES (60%) pushes up the required investments but benefits overall from a significant decrease in operating coste inclusing fossil fuels and carbon prices.

With current levels of variable RES penetration incremental operational requirements, such as hourly balancing and provision of operating reserves, have been absorbed by the system. As penetration continues to expand, however, the operational requirements will expand as well. There is a growing need to make these impacts more transparent, address them in a cost-efficient manner and allocate the associated costs across all relevant stakeholders.

Beyond 2020, when shares of diverse, variable renewables become more significant, enhacing European-wide cross-border cooperation can reduce required investments. In a sensitivity scenario with less coordinated diverse RES deployment, whilst still reaching 50% renewables in 2030, around 20% more investments will be needed for generation in the period 2020-2030.

3.3 ROLE OF GAS

In all scenarios, the analysis shows that gas-fired generation will play an important role going forward. Gas-fired plants provide 22% of the annual power demand in 2010, 25% in 2020 and 28% (25% unabated, 3% gas-with-CCS) in the 2030 *On Track case.* Gas-fired plants act both as flexible baseload (replacing coal-fired generation) and as back-up resource in support of increased shares of diverse, variable RES generation, while conforming to the EC's 2020 and 2030 power sector CO_2 emission reduction goals. Beyond 2030, CO_2 abatement goals are such that gas can only remain a significant fuel source in the power mix if commercially deployable solutions are developed to substantially eliminate carbon emissions from gas-fired generators.

As overall gas consumption is expected to remain stable in the next decades, due to the projected shift in gas usage from the heating sector to the electricity sector, the analysis finds that planned gas network infrastructure by 2020 will be adequate in most areas in Europe. As with the electricity grid, the investments required in the gas network to implement the 2020 plans may require specific incentives[24].

3.4 DEMAND SIDE RESOURCES REDUCE THE BALANCING CHALLENGES IN A DECARBONISED POWER SYSTEM

Power Perspectives 2030 shows that substantial new transmission capacity and large investments in the deployment of low-carbon technologies are vital if we are to keep decarbonisation on track. In search of tools to help deliver these fundamentals, the analysis clearly shows the benefits of stimulating implementation of demand response and energy efficiency measures.

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22 The report assumes that learning rates and cost reductions for RES will increasingly be driven by Rest of World deployment; though demand in the EU remains important. For details, please see exhibit 12 in the report.
23 ECF (2011), Roadmap 2050: Financing for a zero-carbon power sector in Europe http://www.roadmap2050.eu/attachments/files/R2050-Financing.pdf
24 ENTSO-G estimated investments to be around €89,3 bn

Demand response is a dynamic demand mechanism to manage consumption of electricity in response to supply conditions. A realistic demand response potential in 2030, shifting up to 10% of daily load in response to availability of supply, decreases the need for grid capacity by 10% and back-up capacity by 35% and thus helps in managing the risk of insufficient grid transmission[25]. Demand response also reduces the volatility of power prices by better matching demand to available supply, reducing volatility by 10–30% compared to the *On Track case* and by more than 50% compared to a scenario with less transmission capacity. This implies Demand Response is a critical tool in case transmission capacity does not get built as needed, and in all cases reduces costs and mitigates implementation challenges.

Energy efficiency measures also yield substantial benefits in mitigating the investment and grid challenges in the power system. It is also important to compensate for the upward pressure on electricity demand due to electrification of the transport and heating sectors. If similar annual demand reductions as those necessary to achieving the EU's 20% energy savings target by 2020 are applied towards 2030, electricity demand stabilises at a rate of +0.3% per year. This differs from the annual +1.8% demand growth in the *On Track* case and results in a 50% decrease in transmission investment and a 31% decrease in back-up investment, saving €299 billion in investments (i.e 30% lower capex)

4. IMPLICATIONS FOR THE POWER MARKETS

Power Perspectives 2030 employs the analysis to look at two fundamental questions directly relevant to power markets: what role will electricity markets play in achieving decarbonisation, and how will decarbonisation affect the evolution of the electricity markets?

Conventional thermal resources will continue to play a roly as the system decarbonises but the growing share of low marginal cost variable resources in the supply mix, like wind and solar, will transform the operating environment in the energy markets across Europe. Our analysis of market prices finds that a large share of variable RES in the supply portfolio does not necessarily lead to a fall in wholesale energy prices to problematic levels. Such a development can be avoided if power systems are well integrated, with transmission capacity expanded as needed in a timely manner, and if an effective balance is maintained between demand for resources of various types and the supply of those resources. The analysis does provide support for the proposition that wholesale market prices are likely to become more volatile.

This relates to the question of the mix of conventional resources that will be required as decarbonisation progresses in support of continued growth of a diverse portfolio of RES technologies. As the share of variable RES grows, the space in the market for inflexible resources, like some traditional 'base load' plants that are technically and/or commercially incapable of frequent and significant changes in production, will gradually shrink. Conversely, the need for resources capable of operating efficiently and reliably with more frequent upward and downward changes in production will grow. There will also be an increasing need for resources that can survive commercially despite long periods of inactivity interrupted by short periods of steady-state operation.

Steering investments toward the required flexibility of generation resources warrants careful consideration. The concept of separate "capacity mechanisms" has gained traction in some Member States, yet our analysis demonstrates that capacity alone (i.e the undifferentiated ability to produce energy) is not an adequate description of what is needed, and in fact surplus unresponsive capacity can be part of the problem. Market adaptations, if adopted, need to value resources differently depending on their ability to provide the differentiated services a decarbonised power sector will increasingly require. One possible approach to ensuring investment in such resources is to develop "capability-based" market instruments[26] (as opposed to capacity only). An additional concern

25 The EU has regulated and incentivised smart metering rollout across Europe, which is one of the key enablers for demand response, following Directive 2009/72/EC (internal market in electricity).
26 Capability-based market instruments are different from capacity-based market instruments in that they establish system-wide values for capacity services rather than for capacity as such. This is further explained in exhibit 46 of the report.

is that the uncoordinated implementation of national capacity mechanisms poses a signficant risk of frustrating market integration.

Hence, the effectiveness and efficiency of markets for flexible services will be a critical factor in addressing the operational challenge of decarbonisation. Various tools exist to address these operational challenges, including storage, demand response, flexible supply options and back-up plants. The sensitivity scenarios in *Power Perspectives 2030* with higher demand response and energy efficiency have affirmed the significant value of these resources to meeting supply security, competitiveness and decarbonisation objectives. As demand response is largely a flexibility resource, markets and regulators should ensure these have full and equal access in order to determine their true value and incentivise investment.

E. CONCLUSIONS

There are no simple choices. Transparency and information will be of decisive importance in driving broad public, political and commercial support for the transformation. The debate on the EU's energy future has for a long time been blurred by over-simplified analysis, partly based on presenting future options as current realities. The ambition of *Power Perspectives 2030* has been to analyse what needs to happen in the coming twenty years based on today's knowledge of the options and the choices still before us.

To a large extent, the transition to a decarbonised power system is about investments. Whether or not the required level of investment will be forthcoming is in essence a matter of striking a balance between investor risk, the cost of capital, social interests and the economic efficiency of the expected outcomes. Where possible this should be accomplished through coordinated and incremental improvements to existing market arrangements but it is unlikely to happen without governments exerting significant influence on the framework for investments made by market players over a longer time period. The overall challenge is to run a step-wise transformation and gradually build a stronger platform to reach the 2050 end-goal.

Power Perspectives 2030 shows that to remain on track to achieve the 2020 and 2050 energy and climate objectives, existing National Renewable Energy Action Plans, ENTSO-E grid plans and carbon pricing taken together represent a sound and adequate first step and the EU and its Member States must first fully implement them, with sufficient emphasis on public acceptance and financing. This is clearly a challenging task and appropriate measures must be taken to ensure that all stakeholders involved can and will realise these plans. Meanwhile, policy-makers, regulators and market actors must work together to create the right pre-conditions to accelerate decarbonisation towards 2030. Important prerequisites are to ensure regulatory certainty and clarity for investors; build public acceptance; incentives for TSOs; finance, and relevant planning instruments. Already in the current decade, a stronger sense of direction towards 2030 is needed to support investments and enable markets to support the transition to a decarbonised power sector.

Hence, a stable policy & legal framework for 2030 is required, adapted to the scale and nature of the challenges:

1. **Building new and improved transmission grid infrastructure is essential to balance a decarbonised power system cost-effective** and to integrate energy markets. Beyond 2020, the lowest cost solution calls for twice as much additional grid capacity as compared to the planned expansion in the current decade. Lower levels of grid expansion are also feasible but involve trade-offs with higher levels of capital investment, greater price volatility and higher diverse RES curtailment.

2. **It is important to promote a diverse portfolio of low-carbon generation technologies across Europe**, including wind, solar, hydro, geothermal, biomass and other promising low-carbon option, to avoid dependency on a limited range of energy sources in the decarbonisation transition. **Then complementarity of renewables deployment**

and flexible thermal generation is central to that approach.

3. To ensure this diversification, **a perspective for renewable technologies beyond 2020 is required at the European level.** As diverse RES shares in the power mix increase beyond 2020, cross-border cooperation between Member States on planning and implementation provides opportunities to significantly reduce capital investments.

4. Adaptations to the power and carbon markets should be considered to underpin investor confidence in the transition and **steer investment to an adequate mix of resources that are technically compatible.** Traditional capacity-based mechanisms will become increasingly unfit for purpose as needs shift from simple firm capacity to the particular capabilities a resource offers to the system, such as flexibility.

5. **Demand-side resources such as energy efficiency and demand response (including distributed energy storage options and distributed production) represent an attractive means** to reduce the amount of transmission and large-scale generation investments required. Power markets need to promote energy efficiency, demand response, storage (large-scale and distributed), distributed generation and efficiency as system resources on an equal basis with utility-scale supply options.

6. **To keep the CCS option viable both for coal and gas installations,** more needs to be done to drive technology development and demonstration, and gain public support.

7. A physically and commercially integrated European electricity market combined with greater compatibility among national regulatory frameworks and a sufficiently restrictive carbon regime provide the foundation for achieving established GHG abatement objectives affordably, reliably and securely. **However, progress on market integration is lagging and the current ETS linear reduction factor of 1.74% needs to be adjusted to align with the 2050 target of 80% domestic GHG abatement.**

8. *Power Perspectives 2030* clearly identifies some daunting challenges to remain on track to decarbonisation. It is therefore essential for policy makers to provide the right signals and incentives to all players in the value chain as soon and as clearly as possible. As shown in last year's *Roadmap 2050* report, any delay of action will only increase the overall cost and will impose significant stress on the power system. *Power Perspectives 2030* therefore calls upon policy makers on both European and national level to take appropriate action up to and beyond 2020 to remain on track to the 2050 decarbonisation goals.

Chapter I

CONTEXT AND METHODOLOGY

A. CONTEXT

Power Perspectives 2030 goes in-depth on the questions: "What needs to be done in the next two decades?" and "What are the complications on the way to a decarbonised power sector and what are solutions at hand?" The objective of the report is to identify the challenges related to the transition and to bring understanding and trust in the solutions that are required to keep power sector decarbonisation on track in 2030 towards 2050. While last year's Roadmap 2050 substantially increased confidence in the feasibility of the 2050 end-goal, this report aims to contribute to the understanding of the challenges and solution in the transition towards that goal.

Power Perspectives 2030 closely follows the sectoral emissions trajectory set out by the European Commission's 8th March 2011 communication which indicates a CO_2 emissions reduction objective of around 60% in the power sector by 2030. The central scenario, called the *On Track case*, is based on the full implementation of the existing renewable and grid plans up to 2020 and further projects a power mix towards 2030 in line with the EC's emission reduction objectives. This report opted for a 2030 production with 50% renewable energy sources[27] (12% wind on-shore, 10% wind off-shore, 6% solar PV, 10% biomass, 11% hydropower and 1% geothermal), 34% fossil fuels (25% unabated natural gas, 1% unabated coal, 7% fossil fuels-with-CCS) and 16% nuclear across Europe. This differs from the Business-as-Usual case, as described in the PRIMES report called "EU trends to 2030" (update 2009 baseline). In this scenario, the current plans and targets up to 2020 are not implemented and miss the CO_2 reductions in the power sector in 2030 by half[28].

While we recognise that there are other resource mixes capable of meeting the mid-term CO2 reduction range (and we have analyzed some of them as sensitivity scenarios), this report studies alternative resource pathways to 2030 that rely to a greater extent on non-renewable low-carbon technologies as less robust. This is due to, on the one hand, acceptance issues with new nuclear build and, on the other hand, the technical and public acceptance challenges to large-scale deployment of coal with CCS prior to 2030 and gas with CCS post-2030. In particular, an alternative pathway heavily weighted toward unabated gas-fired generation concentrates deployment risks prior to 2030 and carries a higher risk of locking Europe's power sector into a 2030 resource mix with little clarity on further abatement potential as required beyond 2030. Hence, the projection of the On Track case reflects the long-established principle that resource diversification lies at the heart of a prudent energy policy, and that as a result, renewable energy sources will continue to play a pivotal role in the decarbonisation trajectory together with other low-carbon technologies.

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27 Renewable energy sources cover a diverse portfolio of commercial technologies with very different charachteristics. This diversification of resources is important for the security and reliability of electricity supply

28 The baseline 2009 of the EU energy trends to 2030 models power sector reductions to around 28% in 2030 compared to 1990 levels - http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf

Power Perspectives 2030* builds on the findings of *Roadmap 2050

Last year's *Roadmap 2050* report showed that it is not only technically feasible, but also economically affordable to establish a decarbonised European power sector – one in which the share of renewable energy sources ranges from 40% to 80% (based on technologies that are commercialy available[29] with the rest equally split between CCS and Nuclear) as well as 100% RES (with breakthrough technologies) by 2050. The scope and objective of *Power Perspectives 2030* is not to reassess the conclusions of that report but to specifically investigate the medium term (2010–2030).

Power Perspectives 2030 applies the same technology assumptions (learning curves, cost profiles, retirements, etc.) as syndicated and scrutinised in-depth in the lead towards the *Roadmap 2050* report. This involved a large group of different stakeholders in the energy debate ranging from business, utilities, TSOs, academics, NGOs, energy consultants, national experts and best available data from reliable sources like PRIMES, IEA and others.

The analysis in *Power Perspectives 2030* confirms the core finding from *Roadmap 2050* that levelised cost of electricity (LCOE) can be kept under control throughout the transition to a decarbonised power sector. The analysis shows LCOE numbers, including CO_2 prices, for new builds of €89/MWh in 2020 and €85/MWh in 2030, barely differ from the estimated value of 82 €/MWh for new generation in the decade up to today[30]. In addition, they are comparable to the numbers from last year's *Roadmap 2050* report which showed a back-casted LCOE of €84/MWh in 2020 and €86/MWh in 2030[31]. Also in the Higher RES scenario the LCOE remains under control at a level of €86/MWh, mainly due to a decrease in the share of the carbon price.

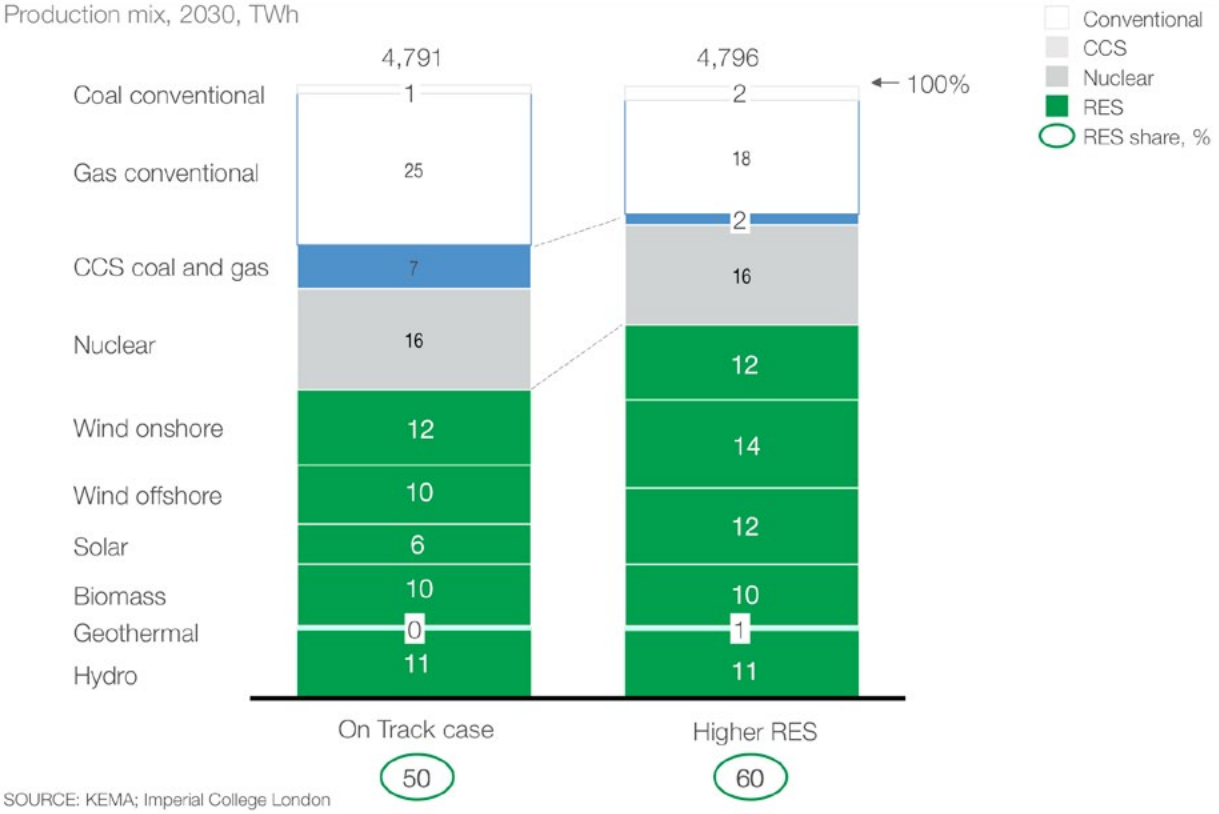
Besides, *Power Perspectives 2030* also concludes, as shown in *Roadmap 2050*, that further developing and deploying technologies for flexible baseload, back-up, demand response, and expanding the transmission grids across Europe are the most economic long term solutions to balance the system. These will be discussed in greater detail in the subsequent sections.

29 Although the technologies used 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

30 This is an estimation of the average LCOE in the decade 2000 – 2010, based on costs estimation of generating electricity from IEA WEO 2009 and NEA (Nuclear Energy Agency) reports published in June 2010. The LCOE per technology is based on latest information from Eurelectric

31 There are a few differences in approach, such as more conservative assumptions on load factors and higher granularity in grid modelling then in Roadmap 2050

Higher RES sensitivity has 60% share of renewable energy sources compared to 50% in the On Track case in 2030



SOURCE: KEMA; Imperial College London

Both in the On Track Case and the Higher RES scenario the LCOE remains under control. Increased capex is off-set by decreased opex

LCOE – excl. CO2 prices · LCOE – CO2 prices · Generation · Transmission build-out · Back up

Scenario	RES share % of total	Emission reduction vs. 1990 %	Curtail-ment % of RES production	LCOE[1] €/MWh	Capex[2] Cumulative per decade, € billion	Opex[3] Cumulative per decade, € billion
2020				2020	2010-20	2010-20
On Track Case	35	34	0.6	85, 4., 89	567, 46, 15, 628	1,643, 2, 1,645
2030				2030	2020-30	2020-30
On Track Case	50	65	0.5	76, 9., 85	1,028, 68, 57, 1,153	2,107, 17, 2,124
High RES	60	70	1.0	85, 1., 86	1,393, 138, 66, 1,597	1,727, 44, 1,771

1 Levelised Cost of Electricity (LCOE) includes generation capex (incl. back-up capex) and opex of new builds (incl. back-up costs and CO2 prices) and capex of additional transmission build out, loadfactor used are estimate for newbuilds as per roadmap 2050
2 Capex includes the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
3 Opex includes annual operating cost for the whole system, including back-up costs and CO2 prices

SOURCE: KEMA; Imperial College London; McKinsey

B. METHODOLOGY

Power Perspectives 2030 is a projection analysis built around the core *On Track case*. The analysis models several sensitivity scenarios ('scenarios') that alter key parameters of the power system and compares these against the *On Track case*. The scenarios are designed in such a way that they bring qualitative and quantitative insight into the effects of changing key elements of the robustness of the power system. As such, the report does not intend to assess the likelihood of different outcomes related to what is currently considered as realistic or not realistic.

Technically, future power demand can be met in both the *On Track case* and the sensitivity scenarios with generation mixes consisting of technologies that are already commercial today or in late development stage. Solutions to balance the system, while providing the same reliability as today, are available in all these cases.

Overview of On Track case and scenarios modelled (1/2)

		2020	2030	2040	Key modelling assumptions
	On Track case	✓	✓	✓	▪ 2020: Full implementation of current plans (ENTSO-E TYNDP & NREAPs) with carbon price reflecting 20% economy-wide emission reduction target. ▪ 2030: Building on implementation 2020 plans towards 50% RES by 2030 ▪ No demand response or additional energy efficiency considered
Sensitivity scenarios	Higher RES		✓		▪ ~60% RES by 2030
Sensitivity scenarios	Less Nuclear and CCS		✓		▪ No new nuclear post 2020 and accelerated retirements of existing nuclear (10% less existing capacity by 2030), leading to capacity of 61 GW in 2030 vs. 105 GW in On Track Case ▪ No CCS post-demonstration
Sensitivity scenarios	Less Transmission	✓	✓	✓	▪ 50% off the additional transmission capacity added since 2010, subject to a maximum of 5000 MW added between 2020 and 2030
Sensitivity scenarios	Less Transmission with Higher RES		✓		▪ ~60% RES by 2030 ▪ 50% off the additional transmission capacity added since 2010
Sensitivity scenarios	Less Onshore Transmission		✓		▪ Based on the Less Transmission scenario, but without constraints on the build of subsea DC cables

Overview of On Track case and scenarios modelled (2/2)

Sensitivity scenarios	2020	2030	2040	Key modelling assumptions
Less coordinated RES deployment		✓		▪ Assuming same overall RES target as 2030 On-Track Case (50%) ▪ Generation mix and allocation of RES among countries based on extrapolation of the 2010-20 NREAP trends into the 2020-30 period
Less Reserve sharing		✓		▪ No regional sharing of reserve; continuation of situation in 2020 'On track' case
Higher Energy Efficiency		✓		▪ Lower demand in 2030 (total demand is -15% less compared to 'On track' case), based on interpolation of Roadmap 2050 energy demand, including more aggressive efficiency assumptions in buildings and industry
Higher Demand Response		✓		▪ Shift in energy of max. 10% within same day, based on fuel shift in transport (more electric vehicles) and buildings (more electric heating / heat pumps able to deliver demand response), compared to no Demand response potential in 'On track' case
Decommissioned plants as back-up		✓		▪ We assume 50% of the decommissioned gas an oil installed capacity from 'On track' case to stay "on-line" after 2020
Overlay Grid			✓	▪ Integration of several potential routes for (long-distance) HVDC connections along the major transport corridors observed in the 2040 - High RES sensitivity

Overall modelling approach

Our approach consists of 3 steps, and models it the generation and transmission capacity requirements as well as the overall level of investments (capex) and operations (opex) for the various scenarios in 2020 and 2030. The approach is subject to the following boundary conditions: achieving the CO_2 emission reduction targets for 2020/2030, reliable power supply (99.97% reliability) and if possible, no early retirements of existing assets [32].

32 In this report we define early retirement to mean the retirement of an asset before the end of its capital depreciation period

Overall approach

1 Demand and production mix 2020 & 2030

- Define power demand: PRIMES demand + fuel shift (from Roadmap 2050[1]) for 2020 and 2030
- Calculate capacity to meet demand based on:
  - Existing capacity
  - Assumed load factors per technology and country
  - Cost curve and maximum potentials of RES

2 Hourly demand and production curves

- Create
  - Hourly demand patterns across the year per country
  - Hourly RES production patterns across the year per country based on historic data

3 Grid and system modelling

- Compute transmission and back-up requirements to meet demand at current reliability at optimal cost
- Simulate the hourly operation of the European power system for a full year (generation and transmission)

Key outputs

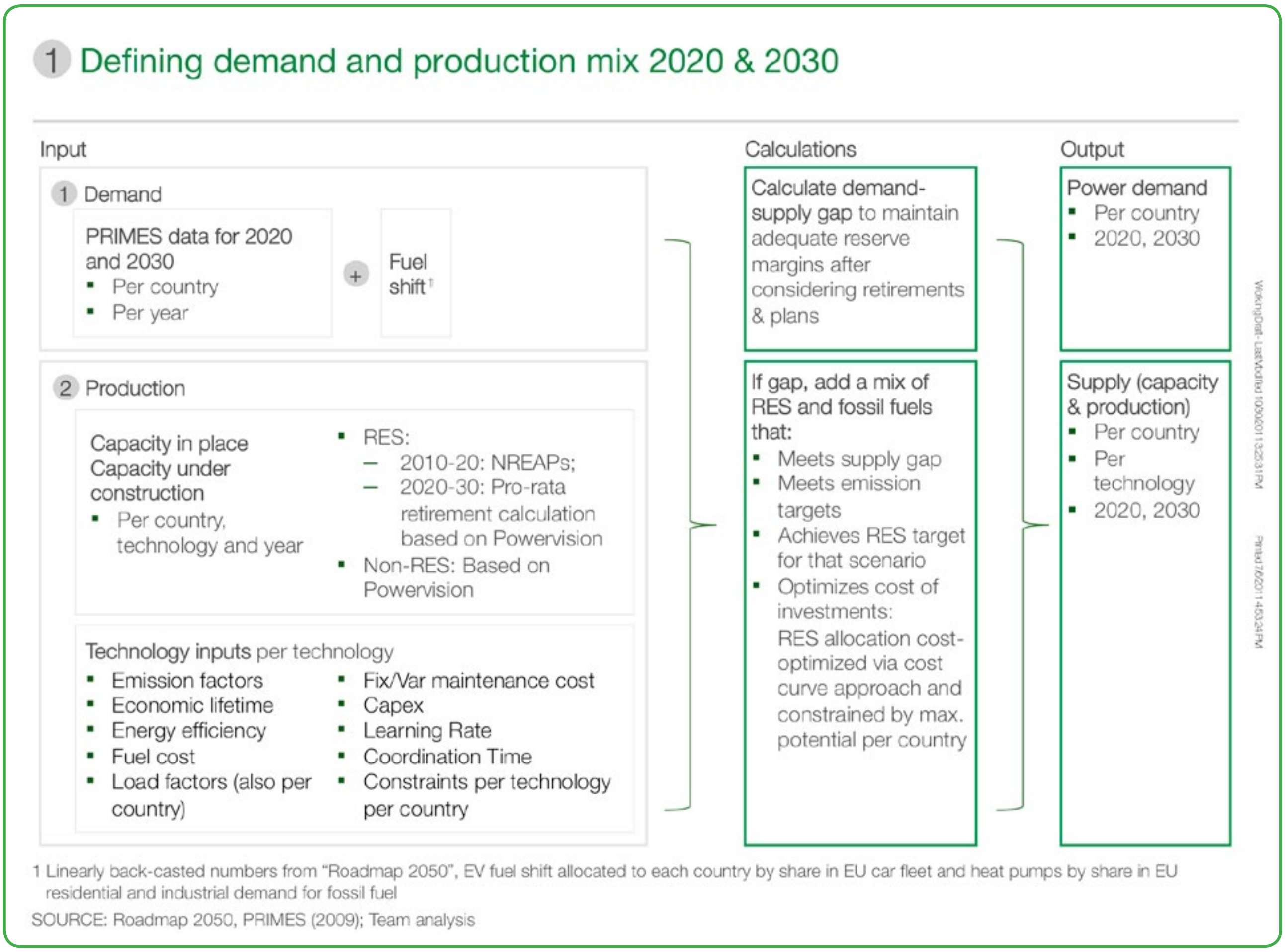
- Adequate system capacity
- Overall cost of generation and transmission investment and operation (incl. back-up)
- Utilization of generation and transmission infrastructure
- Realized penetration of renewables and emissions

1 Linearly back-casted numbers from "Roadmap 2050", EV fuel shift allocated to each country by share in EU car fleet and heat pumps by share in EU residential and industrial demand for fossil fuel

SOURCE: Roadmap 2050, PRIMES (2009); Team analysis

Step 1: Defining demand and production mix

We defined demand and the production mix for 2020 and 2030, based on the following inputs and calculations.



Demand

Power demand is based on the Reference scenario (including policies for 20-20-20 targets) in the PRIMES report "EU energy trends to 2030" (updated in 2009) and adjusted upwards to reflect fuel shift from transport and heating sectors. Fuel shift for 2020 and 2030 is based on an intrapolation from the *Roadmap 2050* estimates for fuel shift in 2050[33].

Production mix

Up to 2020 both capacity and production are based on NREAPs. There are no adjustments for any potential reductions due to implementation challenges on these plans. Beyond 2020 the modelling of the EU-27 production mix uses this 2020 RES deployment pattern as a starting point. The technologies used in the production mix are only those at commercial stage development.

- Inputs

• Existing capacity and capacity under construction: RES capacity is based on NREAPs of each country until 2020. From 2020 onwards capacity that is reaching retirement will start to be rebuilt. RES capacities of 2010-2020 for Norway and Switzerland are taken from Global Insights. Non-RES capacity is taken from Powervision[34 35]

• Technology inputs (emission factors, economic lifetime, energy efficiency, load factors, etc.): the model applies the same standards as in *Roadmap 2050*, though with more conservative assumptions for gas and coal load factors (both conventional and CCS)

33 Electric vehicles are back-casted exponentially, buildings and industry (heat pumps) linearly. Fuel shifts have been allocated to each country by share in EU car fleet (electric vehicles) and share in EU industrial and residential fossil fuel demand (heat pumps). The demand in the higher energy efficiency sensitivity is also based on linear back-casting from *Roadmap 2050* estimates for 2050. In this sensitivity, power demand increases by 0.3% pa from 2020 to 2030 (compared to 1.8% growth in the *On Track case*). This results in 15% less power demand in 2030 in the higher energy efficiency sensitivity when compared to the *On Track case*.

34 We have used Powervision to construct picture of today's capacity in place and capacity under construction.

35 The *On Track case* is constructed ahead of the Fukushima Daiichi nuclear disaster in Japan in March 11th. To reflect the political aspirations and decisions of some European governments on nuclear in the aftermath of the nuclear disaster, we have modelled as specific *Less nuclear & CCS* sensitivity, with no new nuclear built-out post 2020 across Europe and accelerated phase-out in Germany (no nuclear post 2020) and no CCS beyond demonstration plants stage by 2030

- Calculations
  a. Production based on existing capacity and capacity under construction (converted into production by load factors (per country, technology and existing or new-built plant))
  b. Gap between demand and supply (based on a.)
  c. If there is a gap, addition of a mix of RES and fossil fuels that closes the gap is calculated, meeting emission and RES levels and optimizing investments. 2030 RES additions are allocated to countries by using cost-optimized cost curve (constructed based on load factors per country), taking into account constraints for maximum potential per country based on *Roadmap 2050* inputs, expert interviews and industry association reports.

Step 2: Creating hourly demand and production curves for renewables based on historic data

In a second, intermediary step, hourly demand and production profiles are created for load and different types of renewable energy sources (wind, solar and hydro[36]), taking into account regional variations in each of the individual zones of the European grid model:

- Load profiles have been derived from historic consumption patterns but are modified to reflect the impact of energy efficiency and the electrification of the heat and transport sectors.
- Generating patterns are based on meteorological data (wind speed, solar radiation, inflows), which have been converted to electric power by means of turbine or PV models where necessary.

Step 3: Modeling grid and back-up requirements to meet demand at current reliability and at optimal cost

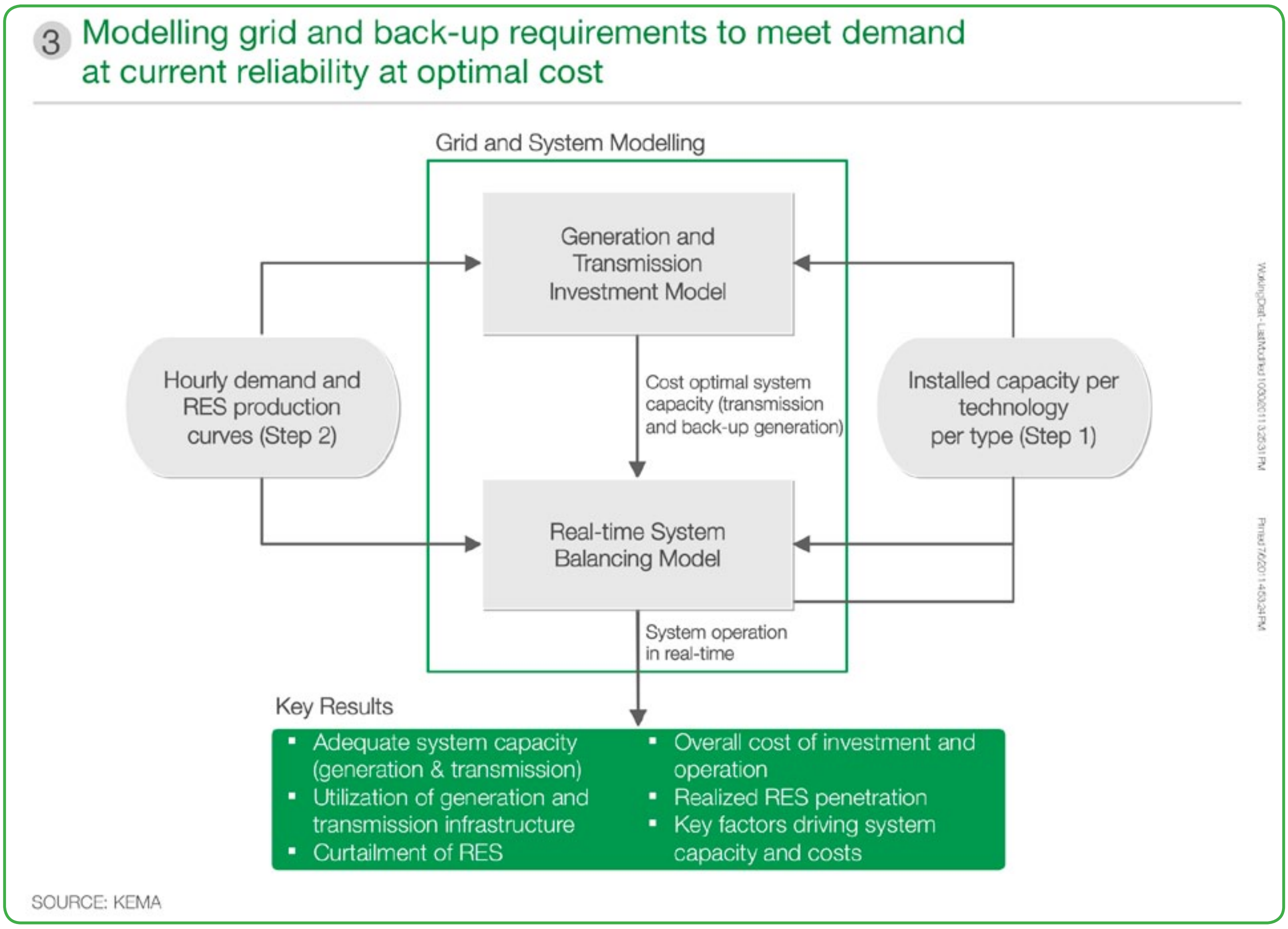
Using the input data established in the first two steps, an integrated grid and generation model, which identifies the optimal build-out of transmission and back-up generation and simulates hourly system operation across the time horizon of a year[37]. As illustrated below, this model includes two separate modules:

- An infrastructure (generation and transmission) evaluation models capture the effects of sharing generation capacity through inter-regional transmission in order to minimize the overall additional infrastructure investments needed to deliver a defined level of reliability. It therefore includes an integrated reliability assessment which assesses whether adequate generation will be available for each hour of the year to meet demand in each part of the entire network, taking into account an array of probabilistic inputs (forced outages, variability of load and RES etc.)

- Thereafter, a detailed production and reserve optimisation model optimizes the hourly operation of the power system across a full year. Using a stochastic optimisation framework, this model has the objective of minimizing generation production cost subject to multiple constraints associated with the dynamic characteristics (stable generation levels, ramp rates, minimum up/down times etc), cost parameters of various technologies, stochastic behaviour of intermittent generation and the need to maintain adequate level of additional operating reserves in the system.

The outputs of this step include necessary capacity and investments into transmission and back-up generation as well as the hourly use of the combined generation and transmission infrastructure, including the associated overall cost, emissions and curtailment of RES.[38]

36 In contrast to wind and solar power, monthly inflows have been used for hydropower
37 The grid model is based on marginal cost. There is no iteration between generation model and grid model.
38 The model does not re-assess geographical allocation of generation based on potential restrictions in transmission line built-out. The impact of such a restriction is modeled in a sensitivity scenario with “less transmission” capacity.



Carbon prices used are €38/ton for 2020 and €85/ton for 2030 and beyond, based on IEA WEO 2010 (450 ppm scenario)[39]. The fuel and carbon price assumptions do not determine the production mix (i.e. the new capacity built) created for the various scenarios - these are determined ex-ante based on the above methodology. They are used in an hour-by-hour dispatch model influencing the dispatch of technologies based on short-run marginal costs.

Levelised cost of electricity - Based on the data we calculated the levelized cost of electrity (see appendix for detailed approach). The calculation takes into account construction time and production over the lifetime of plants. Furthermore, we performed high level modeling of the of current gas infrastructure to test whether this is adequate to accommodate the required gas capacity for power production.

Out of scope - *Power Perspectives 2030*, as all studies, is limited in scope. The study is not intending to give analytical backing for conclusions on:

- Optimal power mixes per single country or specifics region therewithin
- Optimal solutions from a macro economic perspective
- The likelihood of different outcomes related to what is currently considered as realistic
- Revisiting or modifying the results regarding the different pathways in the time perspective 2050 as modelled in last year's *Roadmap 2050* report
- Decentralised generation, storage and other distribution system investments – the study has not attempted to quantify the amount of incremental investments required in the distribution system over and above the amount of investment required in any case. In addition to investments required to increase distribution system capacity, the opportunities for demand response identified in the study – much of which can be expected to take the form of decentralized storage and production - will require investment at distribution level, though in many cases they may also reduce the underlying need to expand the distribution system. We identified significant opportunities to use such demand response measures to reduce the required investment and life-cycle costs of power sector decarbonisation. Further work to quantify these impacts at a local level would be enormously useful.

39 The carbon price is not a variable in the model and hence does not reflect the volatile nature of the ETS. We have assumed that the carbon market would ensure a stable and significant carbon price in line with the intention

Chapter II:

TECHNICAL ANALYSIS

PART A. OBSERVATIONS UP TO 2020

Up to 2020 the Member States of the European Union have agreed on concrete plans and targets related to the decarbonisation of the power sector, like the National Renewable Action Plans (NREAPs) and the Ten-Year Network Development Plans from ENTSO-E (TYNDP). The analysis finds that these plans constitute an adequate first step to decarbonisation, if fully implemented. That means that up to 2020 full implementation of the existing plans is required to put the European power sector on track to decarbonisation.

1. IF REALIZED, PLANNED UPGRADES TO THE ELECTRICITY GRIDS ARE ADEQUATE TO BALANCE THE POWER SYSTEM IN 2020

The currently planned grid enhancements of ENTSO-E, as outlined in the bottom-up TYNDPs, are adequate to balance the system for the next 10 years both in capacity and location. This is illustrated by the low RES curtailment level of 0.6% on average, when modelling the 2020 situation based on the existing grid capacity and power mix when implementing the NREAPs[40]. Nevertheless, curtailment levels are high in specific regions like Ireland (30.7% of wind energy) and Estonia (7.8% of wind energy), indicating a suboptimal balance between generation and transmission capacity in those areas.

The current plans are ambitious, with a projected increase in transmission lines by 42,000 km from 2010 to 2020, representing a 14% increase of the existing network of currently ~300,000 km. As indicated by ENSTO-E, these investments are driven by the triple objective of integration of the European markets, RES balancing and security of supply[41]. In the grid model used for this study, these investments increase the transport capability at the European level by more than 40%, or from approximately 60 TW-km to some 90 TW-km.

This results in a total capex of approxinately €47 billion[42] in the period 2010 to 2020, which is in the same order of magnitude as the estimates provided by ENTSO-E[43]. Utilization of lines is on an average 35% in 2020 (with extremes in some regions ranging from 10% to 96%). The implementation of these plans, however, despite requiring a significant effort by its members, with support from the European Commission, ERGEG, and many key stakeholders, is not legally binding. Hence, several issues could slow progress to full implementation.

40 The power mix in 2020, following full implementation of the NREAPs, is modelled as follows: 34% RES (15% variable, 19% non-variable), 25% nuclear and 41% fossils (15% coal, 25% gas)

41 See in Annex: ENSTO-E Ten-Year National Development Plan – Figure 2: Main drivers for investments in new or refurbished power lines

42 Including €27 billion for new capacity between the 48 nodes of our simplified grid model as well as €22 billion for connecting new off-shore capacity.

43 Based on the TYNDP of ENTSO-E, the costs of 2010-2020 grid expansion can be estimated at some €46-57 billion. Please note that this number is not directly comparable to our own estimates since ENTSO-E considers all investments of European relevance. Conversely, our own assumptions are based on a simplified grid infrastructure and do not take into account for instance the costs of connecting new generation or demand (other than offshore wind) or the costs of refurbishing the existing grid infrastructure.

Current situation is not adequate to balance the 2020 power mix and to accommodate integration of electricity markets

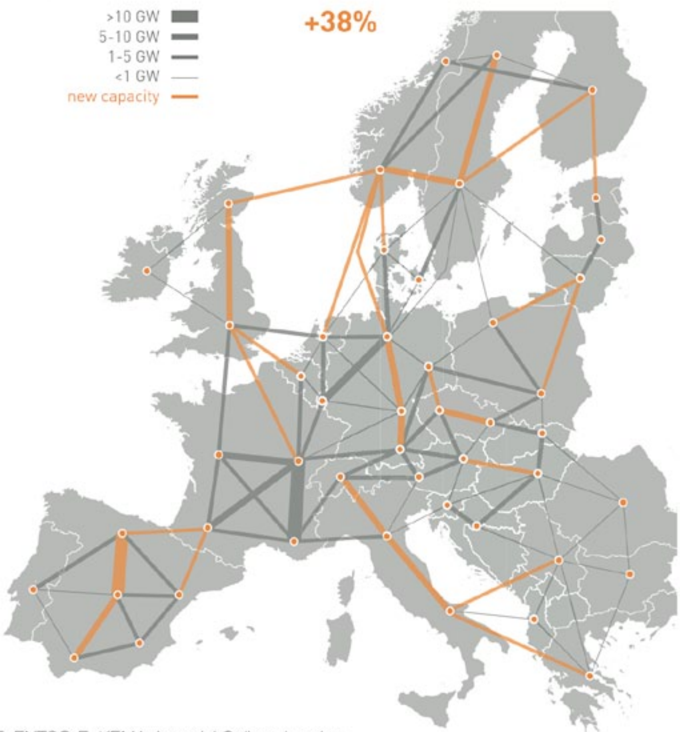
Current grid situation
GW, 2010

2010 existing transmission capacity in EU27+2 is ~165 GW

SOURCE: ENTSO-E; KEMA; Imperial College London

Planned ENTSO-E grid enhancements are substantial…

Planned ENTSO-E interregional grid enhancements
GW, 2020, On Track case



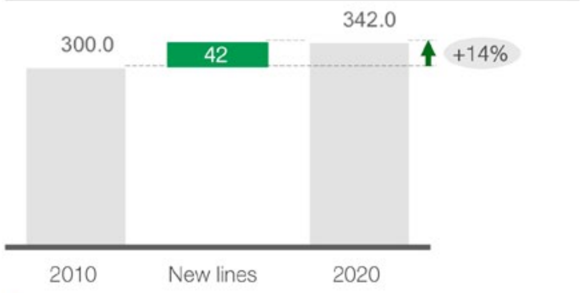
- 2020 additional transmission capacity is ~64 G
- 2020 total transmission capacity will be ~229 GW
- 2020 Transmission enhancement are ~26 TW-km

SOURCE: ENTSO-E; KEMA; Imperial College London

… but adequate to balance the system for the next 10 years

ENTSO-E transmission plans for 2020 are substantial…

New transmission lines[1]
'000 km



- Almost 80% of the new lines will be AC – 32,500 km (of which 91% >300 kV – 29,600 km), with the rest being mostly DC subsea cables – 9,600 km[2]
- 65 GW of additional capacity is expected to be installed by 2020, of which 46% for internal (within the country) links and 54% for cross-border connections
- The total cost is estimated at €24 bln, €16.1 bln for cross-border interconnectors and €7.9 bln for internal links[3]
- An additional €22 bln will be needed for off-shore lines

…but adequate to balance the system

RES curtailment, 2020
%

- The On Track case, based on ENTSO-E plans, has minimal RES curtailment
- European Commission analysis of the investment cost for the PRIMES 2020 Reference Case also showed the network infra-structure investment required to be closely aligned with ENTSO-E forecasts

1 Expansion or refurbishment of lines addressing at least one pillar of EU energy policy (security of supply, integration of RES, support internal market)
2 AC = alternating current; DC = direct current
3 Capacity and investment figures include EU27, Switzerland, Norway, Albania, Bosnia Herzegovina, Croatia, Serbia, Macedonia and Montenegro; Investment figures are based on ICL/KEMA model which is based on ENTSO-E plans; ENTSO-E plans give higher investment forecasts

SOURCE: ENTSO-E; KEMA; Imperial College London

2. RES DRIVEN BY NREAPS WILL CONTRIBUTE SIGNIFICANTLY TO DECARBONISATION OF THE POWER SECTOR

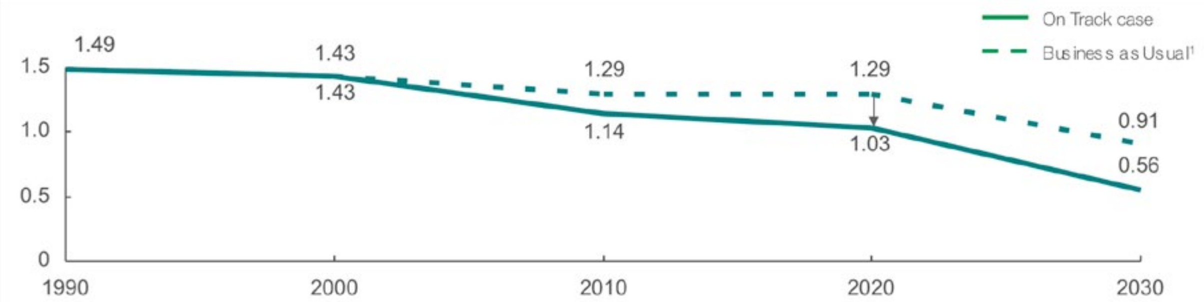
The implementation of NREAPs will lead to achieving the implied RES and emission reduction ambitions[44] for the power sector by 2020, which is different from the Business-As-Usual scenario[45]. The deployment of RES in Europe contributes to ~40% of the emissions reduction in the power sector between 2010 and 2020. Despite the firm commitment in Members States to these binding NREAPs, there is still uncertainty on timely implementation. This will be further discussed in the next section.

44 Based on ETS directive, assuming reduction targets fall equally on all sectors and the proportion of power versus other sectors remains similar across years (26% by 2020)
45 BAU is based on European Commission PRIMES report "EU energy trends to 2030 - baseline" (updated in 2009)

Implementation of NREAPs contributes to achieving RES & emission reduction ambitions for the power sector by 2020

EU-27

Emissions of power sector
GtCO2e



2020	Emissions, %	RES, %
Implied EU ambition power sector	-26[2]	35[3]
Business as Usual[1,4]	-13	26
On Track Case 2020	-34	35

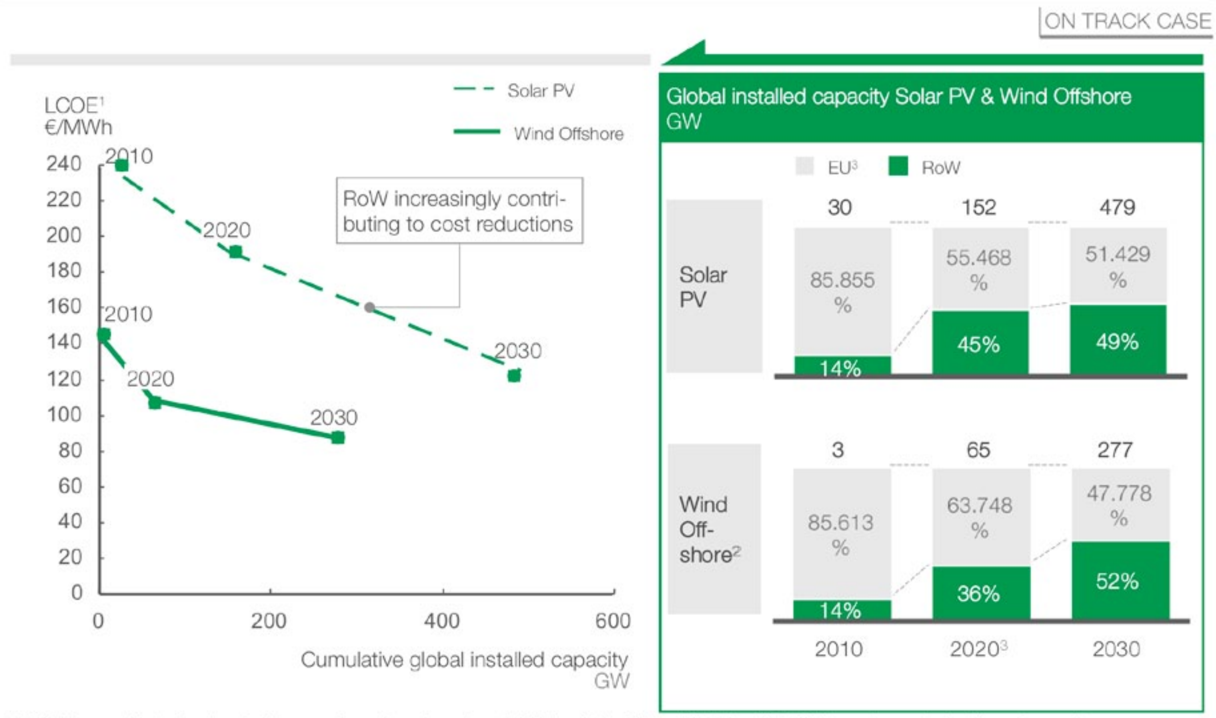
1 Business As Usual based on PRIMES report "EU trends to 2030" – baseline (update 2009)
2 Based on ETS directive, assuming reduction targets fall equally on all sectors and the proportion of power vs other sectors remains similar across years
3 Calculated from 20% RES share target given the share from transport sector
4 Values in BAU include emissions from District heating (<3%)

SOURCE: Team analysis, NREAPs, Roadmap 2050

The European Union will continue to lead in RES deployment up to 2020. As deployment in the rest of the world increases, the European share of total worldwide installed capacity will gradually decrease – for example from 86% in 2010 to 55% in 2020 (and 51% in 2030) for solar PV and from 86% in 2010 to 64% in 2020 (and 49% in 2030) for offshore wind. That means that, certainly beyond 2020, RES deployment in the rest of the world will be substantial and will bring costs down. This will support EU demand, which in return will benefit deployment in the rest of the world[46]. These figures indicate that Europe will remain a major consumer on the global market of RES technologies. Hence, also after 2020, European demand for wind and solar technologies will play a major role in driving global learning rates.

46 The costs will be brought down by the world market well before 2020. See recent reports from UNEP and REN21 Global Status Report (http://www.ren21.net/Portals/97/documents/GSR/REN21_GSR_2010_full_revised%20Sept2010.pdf) indicating significant deployment of renewable in developing countries.

RES cost reductions will increasingly be driven by RoW deployment; though EU demand remains important



1 LCOE for specific technology for Europe; Assuming a learning of 15% for Solar PV and 4.5% for Wind Offshore for each doubling of capacity
2 Assuming 50% of announced wind offshore deployment plans for RoW are realized
3 2020 capacity in EU based on NREAPs
SOURCE: IEA WEO 2010; Team analysis

Summarising, up to 2020, estimated investments for all low-carbon generation of €628 billion (of which €567 billion for generation, €15 billion for back-up capacity and €46 billion for transmission expansion) need to be mobilized, and an additional amount of €1,153 billion (of which €1,028 billion for generation, €57 billion for back-up capacity and €68 billion for transmission expansions) in the period from 2020 to 2030, bringing the total capex between 2010-2030 to €1,781 billion. To put these numbers in perspective:

- The total capex for 2010-2020 corresponds to 0.5% of EU-27 GDP (based on 2010 GDP) per year throughout this decade. It is in the same ballpark as the €800 billion investments required in the period 2010-2020 for the energy sector reported in the EC March 8th Low-carbon roadmap Impact Assessment[47]. The European Commission communication on energy infrastructure from last year[48] indicates that around € 1 trillion must be invested in our energy system between today and 2020 in order to meet energy policy objectives and climate goals.

- The total capex for 2010-2030 is about the same size as the €1.5 trillion EU investment on transport infrastructure from 2010-2030[49].

- Capex for 2010-2030 in *Power Perspectives 2030* is ~€550 billion higher than estimated for this period in *Roadmap 2050.* More than half of this difference is due to higher power demand assumptions (as extra Energy Efficiency measures as in *Roadmap 2050* are not included in the On Track case of this report) and ~20% due to increased scope (HV grids, interconnectors etc) in the grid modelling approach.

47 http://ec.europa.eu/clima/documentation/roadmap/docs/sec_2011_288_en.pdf
48 Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network, European Commission, Brussels, 17.11.2010 - This figure also includes electricity and gas distribution, storage, and smart grids
49 This is based on the European Commission's TEN-T work, including roads, rail, waterways and aviation: http://ec.europa.eu/transport/infrastructure/index_en.html

PART B. COMPLICATIONS ON THE ROAD TOWARDS 2030

In this section, a number of complications and roadblocks are discussed that have to be overcome to remain on track to a decarbonised power sector in the post-2020 time frame.

1. SIGNIFICANT GRID CONSTRUCTION AND INVESTMENTS, BOTH BETWEEN AND WITHIN COUNTRIES, ARE REQUIRED BEYOND 2020

While in the decade up to 2020, ENTSO-E bottom-up plans are generally adequate, significant grid investments are required beyond 2020 to balance the system cost-effectively and to avoid grid congestion and large curtailment of RES. The model shows the need for a near doubling of total grid capacity between 2010 and 2030. Compared to the planned grid expansion up to 2020, the model shows that twice as much new transmission capacity needs to be added in the decade towards 2030 (from 64 GW by 2020 to 109 GW by 2030), or a 50% increase of grid build-out between 2020 and 2030 versus the decade from 2010 to 2020 (from 30 TW-km to 45 TW-km).

Additional investments in transmission grids, including off-shore wind connections, of €68 billion for the *On Track case* will be required from 2020 to 2030. This represents a 50% increase compared to the 2010-2020 investments as outlined by the Ten-Year Network Development Plan of ENTSO-E (approx. €46 – 57 billion)[50].

Cross-border lines represent around 2/3 of additional grid capacity and the corresponding investments (82 GW new capacity and €31bln/TW-km). That means that a not insignificant amount of the required transmission capacity is within a Member State. The largest additional interconnection capacities are built between South UK and Ireland (13 GW), North West Germany and West Germany (10 GW), South West France and North East Spain (9 GW) and North UK and South UK (8 GW).

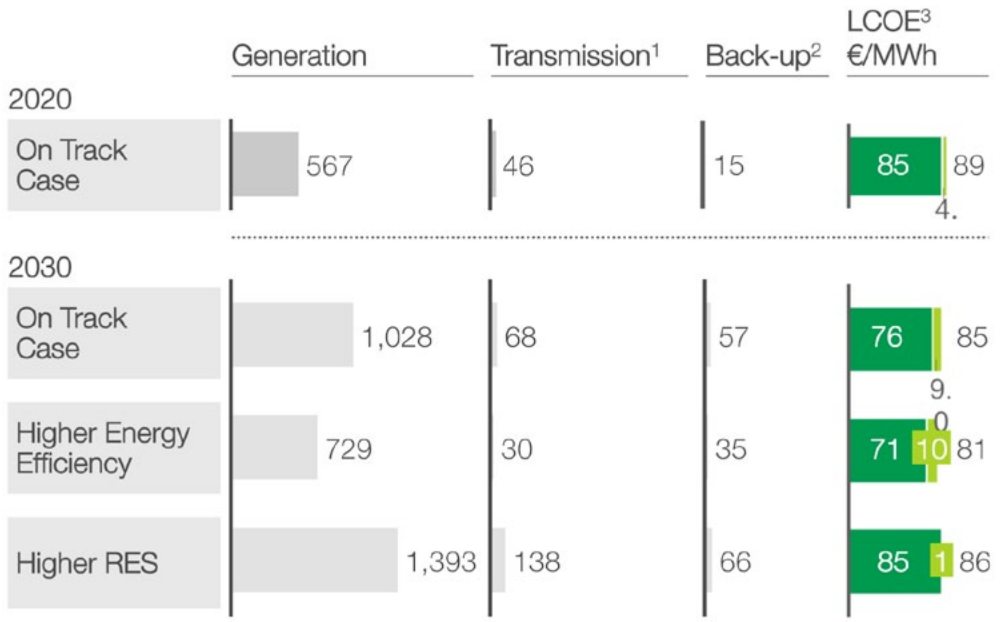
The extent of required grid enhancements will depend on the generation deployment in the scenario, with the low case of an additional €30 billion assuming energy efficiency improvements reduce total energy demand from 4,800 TWh to 4,100 TWh by 2030[51], and the high case of an additional €138 billion assuming a higher share of RES (60% versus 50% by 2030 in the *On Track case*).

50 The €68 bln amount is higher than the ~€60 bln for this period calculated in Roadmap 2050, due to the more granular model and less aggressive energy efficiency assumptions used in Power Perspective 2030, leading to higher power demand

51 In line with the Roadmap 2050 assumptions on energy efficiency

Additional investments in grid are required beyond 2020, but they are low compared to the total investments including generation

Capex, Cumulative, € billion



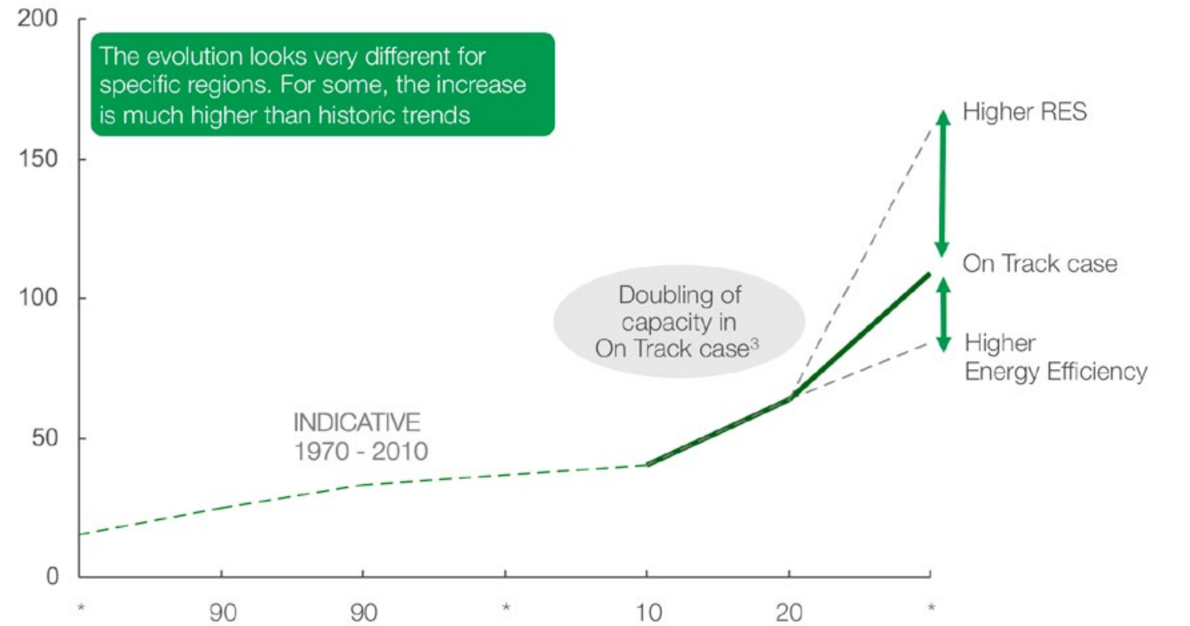
1 Transmission includes both onshore and offshore grid build out
2 Assuming gas fired OCGT plants
3 Levelised Cost of Electricity (LCOE) includes generation capex (incl. back-up capex) and opex of new builds (incl. back-up costs and CO2 prices) and capex of additional transmission build out, loadfactor used are estimate for newbuilds as per roadmap 2050

SOURCE: KEMA; Imperial College London; McKinsey

To reach the required grid capacity over the next 20 years, the current rate of construction has to speed up

Additional expansion of transmission grid capacity[1]
GW, EU-27, Norway, Switzerland and periphery[2]

INDICATIVE



1 Development of grid is assumed to be driven by the penetration of variable power sources (solar PV, wind onshore and wind offshore)
2 Periphery consists of Montenegro, Serbia, Macedonia, Albania, Bosnia-Herzegovina, Croatia
3 From 2020 to 2030 compared to On Track Case

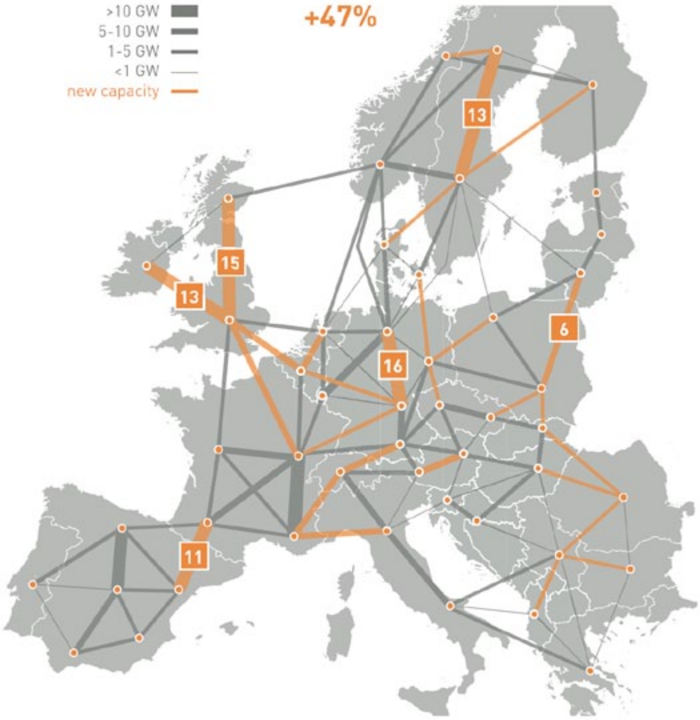
SOURCE: KEMA; Roadmap 2050 analysis

In the context of overall investments of €795–1,596 billion (€1,153 billion for *On Track case*), the investments in grids at 4–9% of total investment (6% for *On Track case*) are comparatively low.

beneficiaries is not straightforward and depends on the time perspective and the constituency. In the long run, interconnecting markets and establishing an electricity trade mechanism will reduce the overall

Need for new transmission between 2020 and 2030 is ~ 109 GW in the On Track case

Transmission required
GW, 2030 On Track case (50% RES in 2030)



- Additional transmission capacity 2030/2020 On Track Case is ~109 GW
- 2030 Total transmission capacity (EU 27+2) ~ 338 GW
- Transmission investment of ~45 thousand GW-Km
- Largest increase in transmission capacity (>5GW) between 20-2030 are for:
  - South UK – Ireland
  - North West Germany – West Germany
  - South West France – North East Spain
  - North UK – South UK
  - South East France – Switzerland
  - South UK – Belgium

SOURCE: KEMA; Imperial College London

Several issues could slow progress both in the current decade for the ENTSO-E plans and in the future for other investments.

- Complex and disjointed planning and consenting regulations could cause delays and even block construction of lines in some cases.

- Lack of direct grid policy and/or failure to develop grid policy in conjunction with renewable policy.

- Lack of clarity regarding the cost allocation of between country grid costs at an EU basis, i.e., who will pay for this infrastructure?

- It is widely advocated that the 'beneficiary-pays' concept should apply to grid interconnections amongst two or more energy markets. However, establishing

cost from reduced back-up investment and lower RES curtailment and will benefit society as a whole. In the shorter term, there will be both winners and losers. In an interconnected market prices tend to flatten out, which means that in some Member States prices will increase and in others prices will decrease as transmission levels reduce options for arbitrage between markets. Counterbalancing that effect will be a reduction in price volatility.

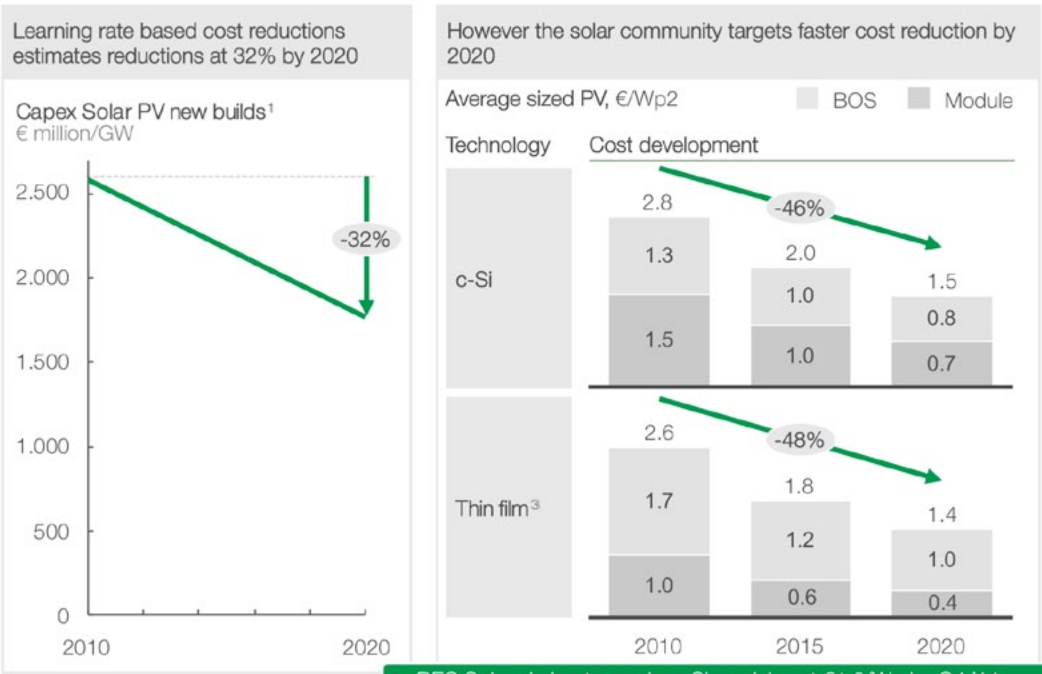
2. SUBSTANTIAL INVESTMENTS IN LOW-CARBON TECHNOLOGY DEPLOYMENT ARE REQUIRED, BUT COMPLICATIONS EXIST FOR EACH TECHNOLOGY

2.1 RES

As with other technologies, it is difficult to predict how the cost of RES technology will change over time. At current learning rate and fuel cost assumptions in this study, wholesale grid parity will only be reached for onshore wind in 2020 and not for solar and offshore wind[52]. The cost of certain RES technologies (such as solar and offshore wind) could come down at a faster rate than a pure learning-rate-led reduction if we see the steep cost reductions envisaged by the supply chain industry. For example, we assume a 15% learning rate cost reduction for each doubling in capacity for solar PV, leading to a 32% decrease in the capex required for 2010–2020 whereas the solar community targets a faster cost reduction of 45–50% by 2020, and prices for solar panels have been dropping at a rapid pace. For offshore wind, we assume a 4.5% learning rate for each doubling of capacity, leading to a 19% decrease in capex required for 2010-2020. Even though capex for offshore wind projects has actually increased more than 50% since 2005, the wind community expects stronger cost reductions, e.g., by lowering opex and increasing yield.

Uncertainty on PV cost developments: the model assumptions are at the conservative end

Solar PV example



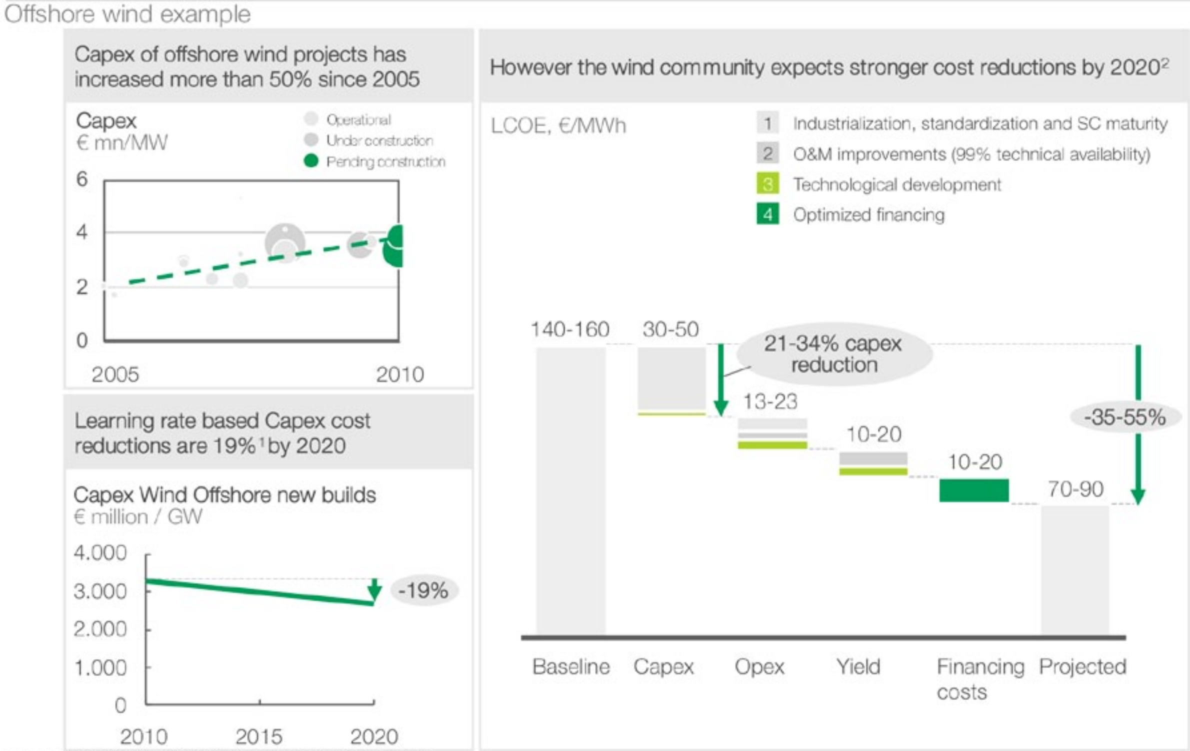
- REC Solar aiming to produce Si modules at €1.0/Wp by Q4 '11
- First Solar aiming to produce thin film modules for €0.8/Wp by 2015
- Past five months prices for solar panels have dropped by ~17%

1 Assuming learning rate of 15% for each doubling of capacity
2 Assuming exchange rate of 1.35 $/€
3 Average of Micromorph, CdTe, and CIGS

SOURCE: EIA; PV Watts; SERC; Eurostat; Utility publications; McKinsey Global Solar Initiative; PV Tech, FT(Solar power industry looks on the bright side, June 8, 2011)

52 Depending on the technology, solar does not necessarily compete with wholesale prices and may well reach retail parity in several markets by 2020 or shortly thereafter For example: Solarv PV is expected to reach grid parity for residential markets in some Member States as early as 2012.

Uncertainty on offshore wind cost developments: the model assumptions are at the conservative end



1 Assuming a learning rate of 4.5% for each doubling capacity
2 Feasibility confirmed by industry experts

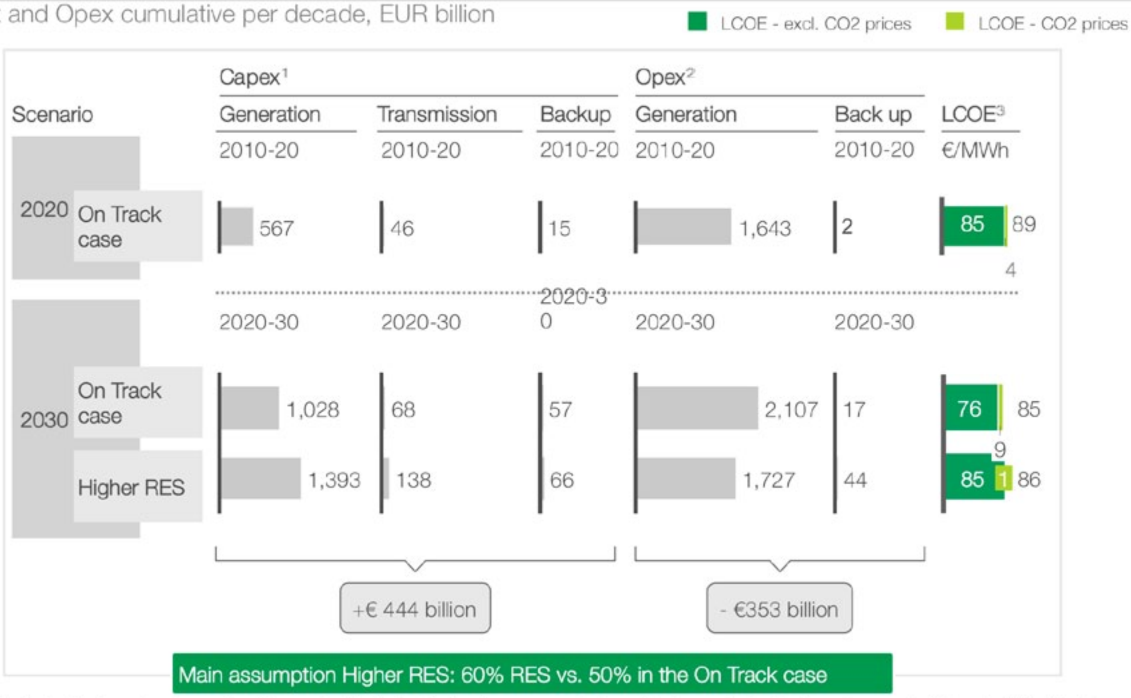
SOURCE: Roadmap 2050 Roadmap 2050; team analysis

When comparing the higher RES scenario (60% RES share in 2030) with the *On Track case*, the model shows a ~40% increase in overall capex costs for 2020–2030 (Generation investments of €1,393 billion versus €1,028 billion in the *On Track case*, transmission grid investments of €138 billion versus €68 billion, and back-up capacity costs of €66 billion versus €57 billion). This is offset by lower generation opex[53] of €177 billion per year versus €212 billion in the *On Track case* and greater CO_2 emission reductions of 70% by 2030 versus 65%. If renewables follow an accelerated cost reduction trajectory (or if costs of other low carbon technologies spiral), this pathway becomes more attractive[54]. However, currently, on European level, there is no clear way forward for renewables beyond 2020. [55]

53 The opex numbers are calculated for 2020 and 2030 as a cumulative number per decade (ie. the cumulative costs are 10x the annual opex at the end of a period.) This is consistent with the methodology applied in last year's Roadmap 2050 analysis.
54 The learning curves and cost reductions of renewables are rather conservative compared to Industry. See p-31
55 Currently, the Directive 2009/28/EC of 23 April 2009 (on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC) recognises that the lack of transparent rules and coordination between the different authorisation bodies has been shown to hinder the deployment of energy from renewable sources.

Moving to a higher RES share will result in higher capex, offset by lower opex and lower emissions. Overall cost remains within similar ranges

Capex and Opex cumulative per decade, EUR billion



1 Capex includes the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
2 Opex includes annual operating cost for the whole system, including back-up costs and CO2 prices
3 Levelised Cost of Electricity (LCOE) includes generation capex (incl. back-up capex) and opex of new builds (incl. back-up costs and CO2 prices) and capex of additional transmission build out, loadfactor used are estimate for newbuilds as per roadmap 2050

SOURCE: KEMA; Imperial College London; McKinsey

2.2 NUCLEAR

In nuclear technology, there are only two examples of new build using EPR technology in Europe (in Finland and France). Both projects have been subject to significant cost and schedule over-runs. In the aftermath of the Fukushima nuclear incident, additional safety requirements are likely to create further capex requirements – creating greater uncertainty for investors and making the deployment of new nuclear even more dependent upon public financing support.

Thus, for both existing and new nuclear capacity, there is a large uncertainty about development of cost, pending the EU stress tests that are currently being performed and potential additional security regulations following those and national nuclear safety assessments.

Two plants with new nuclear EPR technology are under construc-tion in Europe; both facing significant cost and schedule overruns

Project	Description
Finland – Olkiluoto 3	▪ First EPR project to come online ▪ Project schedule ▪ First concrete in October 2005 – Nuclear operations expected in 2013 – Project owner: TVO ▪ Significant cost and schedule overruns reported: Time overrun of ~4 years and cost over-run of € 2.7 billion taking total costs to € 5.7 billion ▪ Losses largely carried by Areva (largely owned by the French state)
France – Flamanville 3	▪ First reactor in France to come online since 1999 ▪ Project schedule – First concrete in December 2007 – Nuclear operations expected in 2014 ▪ Overall project developer: EdF ▪ Significant cost and schedule overruns reported: Time overrun of ~2 years and cost over-run of 50% taking costs to € 5 billion ▪ Losses largely carried by the French state, shareholder of EdF & AREVA

"Most countries won't raise the fundamental question about nuclear use like Germany did. But anyone who builds a plant will in future have to **deal with stricter technical and political standards**, and **higher costs as a result**"

*- **Dr. Johannes Teyssen**, CEO - E.on, Financial Times, June 27, 2011*

SOURCE: Areva; Bloomberg Businessweek (July 2010), FT (June 2011)

2.3 CCS

CCS technology for large integrated power projects has not yet reached the stage of commercialisation planned for 2020. Demonstration plants of 250–300 MW are expected to come on line around 2015 and to ramp it up for larger plants of 500–600 MW. Capital costs are expected to come down by the time of commercialisation (capital costs for current demonstration plants are €3-4 million per MW and total approximately €1 billion) to make the technology competitive with other low-carbon solutions. However, some projects have been cancelled or delayed, and of the total 22 projects applying for NER300 funding in Europe, only 8 will actually receive the incentive. Demonstrations at full-scale are necessary to make commercial deployment successful and CCS cost-competitive with other low-carbon energy technologies.

The emphasis for CCS has been on coal-powered generation and despite the UK having announced the eligibility of gas-fired power stations in its own national competition, there are only a couple of projects in Europe (Mongstad and Peterhead) actually looking at such installations.[56] The business model for CCS investments has not yet been developed. It is unclear how the further policy, mandates and incentives will be designed for a) the emitter, b) CO_2 capture, c) transport and d) storage. Oil & Gas companies so far show only moderate interest in owning and operating storage facilities for CO_2 due to the uncertain regulatory environment, which increases risks and jeopardises potential returns[57].

56 The NER300 structure implicitly targets coal-with-CCS as it favours ton of CO2 captured rather than MWh produced.
57 There are currently some regulatory regime(s) in place, most importantly the Directives 2009/31 on Geological Storage

3. LACK OF PUBLIC ACCEPTANCE OF TECHNOLOGIES AND INFRASTRUCTURE IS SLOWING PROGRESS

The deployment of grids, RES, new nuclear and CCS can slow at the national level due to planning issues, issues with public acceptance[58] and construction permissions. Delays or cancellation in the build-up of grid infrastructure may also indirectly hinder RES deployment.

In the wake of the Fukushima accident, deployment of nuclear energy is being phased out in Germany and Switzerland and blocked in Italy. Governments in France, the Netherlands, Sweden and the UK have expressed continued support for nuclear deployment although the level of continued public support is less clear.

EU member states have split reactions on future of nuclear power after the Fukushima incident, affecting expansion plans

Country	Description	
Germany	• 3 month closure of the country's nuclear power reactors that began operation in 1980 • Government decision to decommission all nuclear power generation in the country by the end of 2022	Changes vs. earlier position
Italy	• After a referendum, new nuclear option is off the table for an undetermined period of time	
Switzerland	• Abandoned plans to build new nuclear reactors	
Bulgaria	• Plans to build unit at Kozloduy instead of Belene (current plans) because of low seismic activity	Additional measures
Finland	• Nuclear & radiation safety authority STUK to conduct review of nuclear facilities' emergency preparedness	
Hungary	• European nuclear stress tests for Paks (sole nuclear reactor)	
Belgium	• Lifetime extension for plants to be shut in 2015 being discussed. Existing plants undergoing stress tests	
Czech Rep	• Decision to continue with plans for nuclear new build	No changes vs. earlier position
France	• No change in policy; Construction work on the EPR at Flamanville continues	
Lithuania	• New tender proposals submitted for a replacement plant, Visaginas	
Netherlands	• Government has decided to carry on with plans for nuclear new build	
Poland	• No change in policy from the Polish government, referendum considered	
Romania	• No change in policy from the Romanian government	
Slovakia	• Commitment to nuclear power continues	
Slovenia	• No change in the nuclear policy of the Slovenian government	
Spain	• No change in policy from the Spanish government. First instance court confirmed closing of Garoña plant.	
Sweden	• No policy change, allow existing nuclear reactors to be replaced at the end of their lifetime	
UK	• The government is pushing ahead with plans for atomic power, confirming the 8 locations it has deemed suitable for new plants by 2025 in its first policy statement since Fukushima	

EU stress tests will be performed on all plants during 2011

SOURCE: WNA; Team Analysis

58 The type and appearance of public opposition to certain technologies can be of very different nature. Where opposition to certain RES and networks is mainly classic NIMBY'ism, opposition to nuclear energy of CCS can be of a more principle nature.

Public acceptance of CCS is currently lacking in many countries. This is leading to delayed and cancelled projects and may drive storage to offshore locations[59].

Regulation and public acceptance of CCS is currently lacking, delaying investments and potentially driving storage offshore

Recent CCS projects

Project (Operator, country)	Status	Comments (Date)
Barendrecht storage (Shell, Netherlands)	Cancelled	Lack of public support and delays in permitting (November 2010)
Finncap (Fortum, Finland)	Cancelled	Financial and technological risks (November 2010)
Kingsnorth (E.On, UK)	Cancelled	Construction of new coal plant where CCS was to be installed was seen as uneconomical due to a slump in power prices. The power plant was also object of public opposition. (October 2010)
Porto Tolle[1] (Enel, Italy)	Cancelled /delayed	Italy's supreme court has halted plans to convert the oil plant to coal with CCS. Enel is currently deciding whether to start the permitting process from scratch (6 years) or take project elsewhere. (May 2011)
Mongstad (Statoil, Norway)	Delayed	Government has delayed funding decision to 2016 due to environmental and health concerns. (March 2011)

Public opinion on CO2 storage

"Due to lack of public support, the Netherlands will not continue to store CO2 onshore […] however it can still happen offshore without causing public disturbance" Dutch Minister of Economic affairs, 15/16-2-2011

"The municipality of [the Dutch town of] Grootegast has unanimously spoken out against CO2 storage under its town" Energia, 21-10-2010

There will be no CO_2 storage facilities in Schleswig-Holstein [Germany] against the will of the local population
Peter Carstensen, prime minister Schleswig Holstein

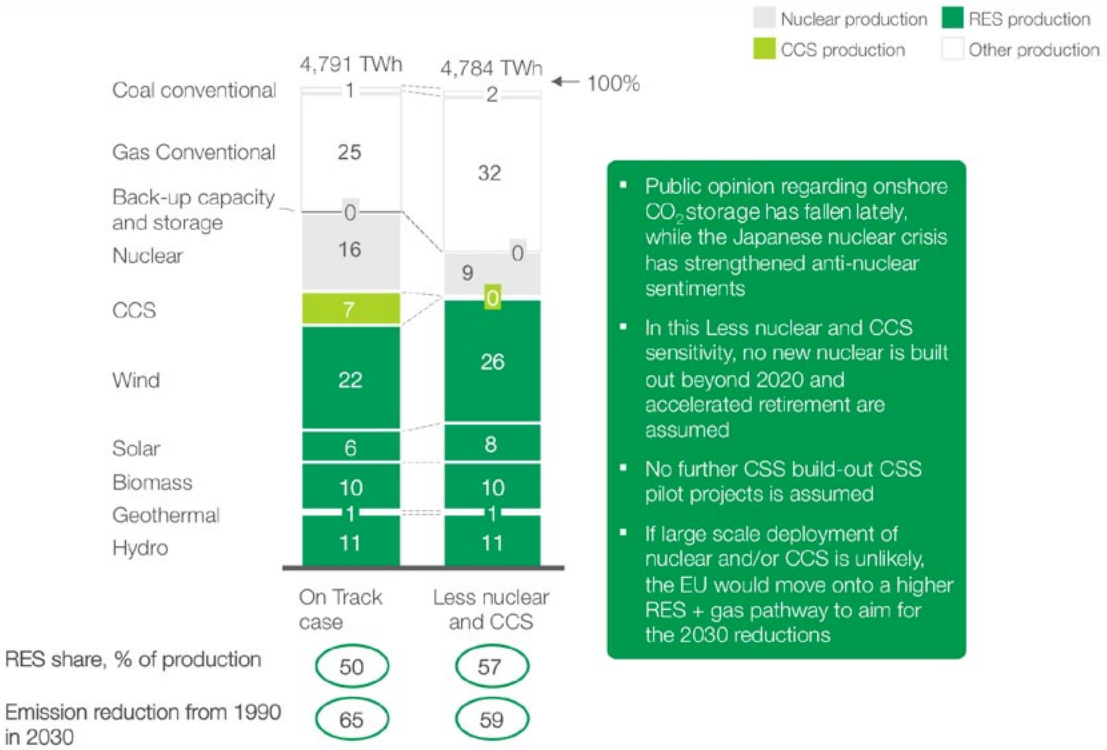
1 This project was a recipient of the EU economic recovery package
SOURCE: Press search; Team analysis

If both nuclear and coal-with-CCS do not deliver beyond 2020, a pathway with higher renewables and gas penetration appears inevitable. The recent developments around CCS and nuclear reinforce the growing understanding that diverse RES are critical to ensuring continued decarbonisation of the power sector, and that shifting from coal to a complementary portfolio of renewables and natural gas is the quickest way to reduce emissions.

A scenario with less nuclear and CCS shows an (~12%) increase in overall required investments for 2020–2030[60] (generation capex of €1,131 billion versus €1,028 billion in the *On Track case*, transmission grid investments of €107 billion versus €68 billion and comparable capex for back-up of €57 billion). Additionally, we observe higher generation opex of €224 billion per year versus €212 billion per year in the *On Track case.*

59 Although the actual Eurobarometer in 2011 showed a slight increase of the public awareness for CCS, public resistance led already to cancellation of CCS projects in some Member States, (e.g. NL, Germany).
60 The cost picture may change, in the advantage of a scenario with less nuclear, due to large uncertainty about development of cost for both existing and new nuclear capacity, pending the EU stress testing and potential additional security regulations following those and national nuclear safety assessments.

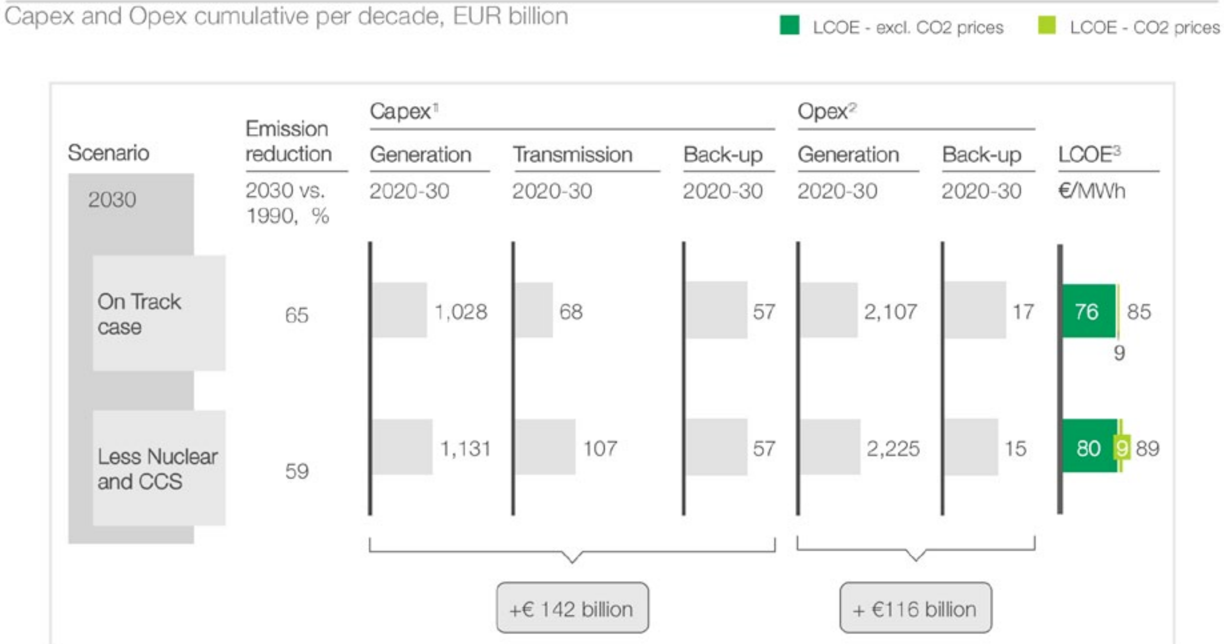
If both CCS and nuclear contributions are limited, more RES and gas is built.



- Public opinion regarding onshore CO_2 storage has fallen lately, while the Japanese nuclear crisis has strengthened anti-nuclear sentiments
- In this Less nuclear and CCS sensitivity, no new nuclear is built out beyond 2020 and accelerated retirement are assumed
- No further CSS build-out CSS pilot projects is assumed
- If large scale deployment of nuclear and/or CCS is unlikely, the EU would move onto a higher RES + gas pathway to aim for the 2030 reductions

SOURCE: KEMA, Imperial College, McKinsey

This scenario is accompanied by slightly higher Capex and Opex and a slightly slower emission reduction trajectory in 2030



1 Capex includes the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
2 Opex includes annual operating cost for the whole system, including back-up costs and CO2 prices
3 The model used uses conservative learning rates of solar and wind, below industry expectations

SOURCE: KEMA; Imperial College London; McKinsey

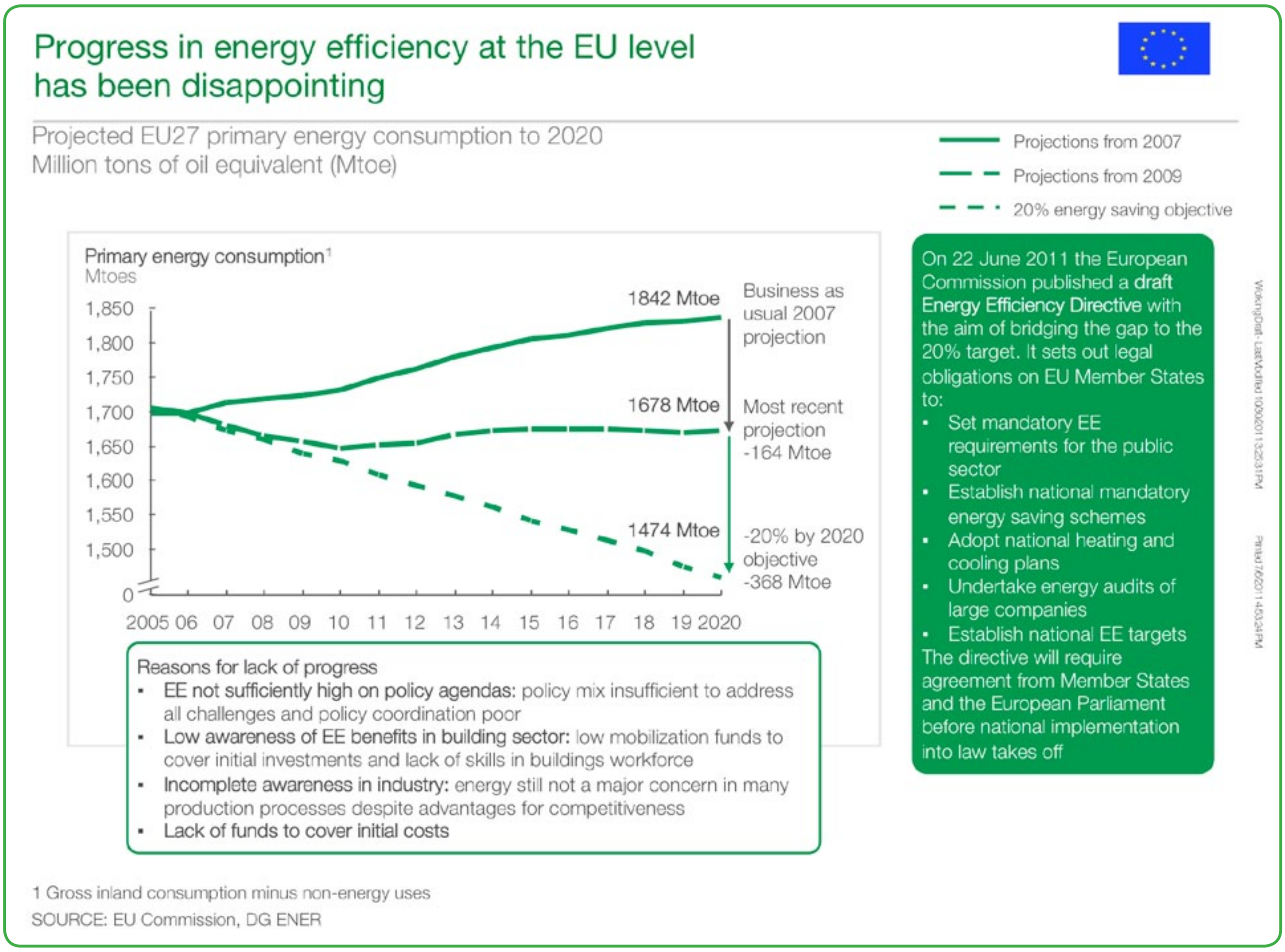
4. ENERGY EFFICIENCY PROGRESS HAS BEEN SLOW

Progress on energy efficiency (residential as well as commercial) has been slow due to the lack of regulatory push, effective business models and a number of implementation challenges. The European Commission published an assessment earlier in the year that estimated the EU is to achieve less than half of the 2020 energy efficiency target (a 9% instead of a 20% reduction in energy use by 2020). On June 22nd 2011, a proposal from the European Commission for a directive on energy efficiency (EED) was adopted in response with the aim of bridging the gap to the 20% target.

power sector builds up as baseload capacity (increase of 11 GW from 2020 to 2030 - from 233 GW to 244 GW) and as back-up capacity (increase of 164 GW from 2020 to 2030 - from 42 GW to 206 GW). This increase takes place while conforming to the 2020 and 2030 CO_2 emission reduction range.

Beyond 2030, CO_2 abatement goals are as such that gas can only be a significant destination fuel in the power mix if commercially deployable solutions are developed to eliminate carbon emissions.

The model shows that the planned gas infrastructure by 2020 will be sufficient in most areas for the next two



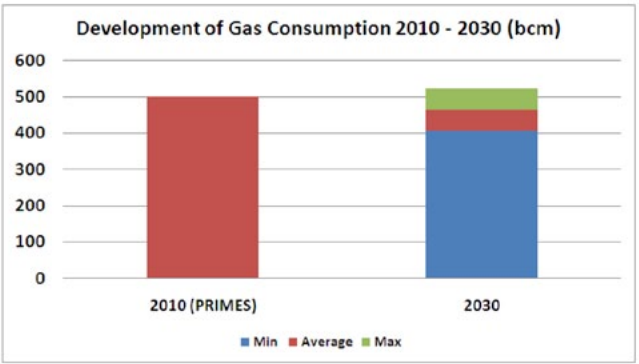
5. ROLE OF GAS AND ADEQUACY OF GAS NETWORK INFRASTRUCTURE

The analysis shows that in the *On Track case*, gas plays an important role, meeting 22% of the annual power demand in 2020 and 27% in 2030. Gas capacity in the

decades, despite the growth of gas for electricity. This is because gas consumption is expected to decline in residential demand by 60%[61] due to projected electrification (to e.g., heat pumps or CHP) and energy efficiency measures.

61 This is based on the fuel shift assumptions in ECF's *Roadmap 2050* report, and used in a report from the European Gas Advocacy Forum: *Making the Green Journey Work*, February 2011.

Additional gas consumption for power generation largely compensated by reduced demand from residential sector



Gas consumption by sector (bcm/a)	2010 PRIMES	2030 (On Track Case)	2030 (All scen.)
Power generation	165	253 (1)	180 – 297 (1)
Residential	184	74 (2)	74 (2)
Industry and others	152	152 (2)	152 (2)
Total	501	483	406 - 523

- Simulations generally show a significant increase of gas-fired generation (up to 80%)
- Simultaneously, a recent study for the European Gas Advocacy Forum forecasts a major decline of residential consumption (- 60%) for several scenarios, based on the 60% RES scenario from "Roadmap 2050"[2]

1 Based on results of grid modelling
2 Based on assumed growth rates from Roadmap 2050 and EGAF study ('Making the Green Journey Work - Optimised pathways to reach 2050 abatement targets with lower costs and improved feasibility')

SOURCE: KEMA; ICL, McK/EGAF analysis

Tailored remuneration schemes may be required to ensure the investment for building the gas network infrastructure, estimated by ENSTO-G to be around €89,3 bn[62]. As with the electricity grids, specific incentives may be required to attract these investments.

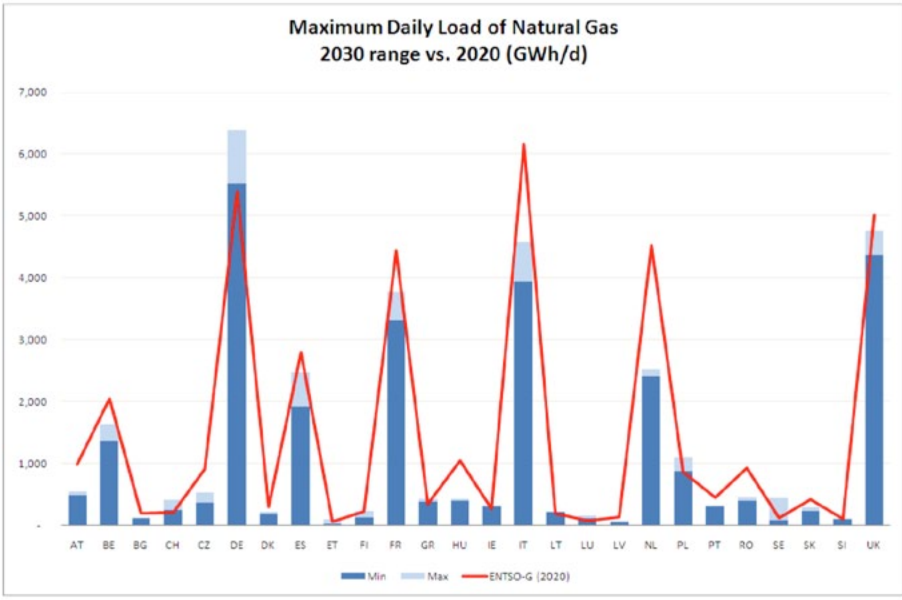
A more detailed view at country level reveals regional variations, with consumption declining in many countries (including the Netherlands and the UK), but increasing in others (for instance Poland, France, Norway and Sweden). Moreover, whilst total consumption declines, maximum daily demand decreases at a slower pace or even remains constant. Similarly, due to the increasing share of OCGTs, demand variations during the day and/or hourly peak load increase in several countries (depending on the variation), even without considering the potential delivery of operating reserves during the operating day. Our analysis shows that, in some regions, the amount of gas-fired generation may thus exceed the capability of the local gas infrastructure to supply sufficient flexibility. This issue could be mitigated to a large extent by enabling back-up gas-fired generation to operate on liquid fuels on a limited basis.

These observations principally also hold for the *Less nuclear and CCS* scenario, which projects gas to grow to 32% of overall generation. This scenario results in a major growth of gas consumption in Germany (and Switzerland), while in France, the Netherlands and the UK this increase is compensated by a decline in gas for heating. Moreover, most of the additional consumption comes from gas-fired CCGTs operating as flexible base load, which means that the increase in daily and hourly demand is much smaller.

62 Source: Ten Year Development Plan 2011 – 2020 from ENTSO-G, February 2011 - http://www.entsog.eu/download/regional/ENTSOG_TYNDR_MAIN_23dec2009.pdf

In many cases, maximum demand is more stable, indicating a decreasing use of the gas infrastructure

Difference in daily gas demand vs. 2020 forecast by ENTSO-G
GWh/d, 2030

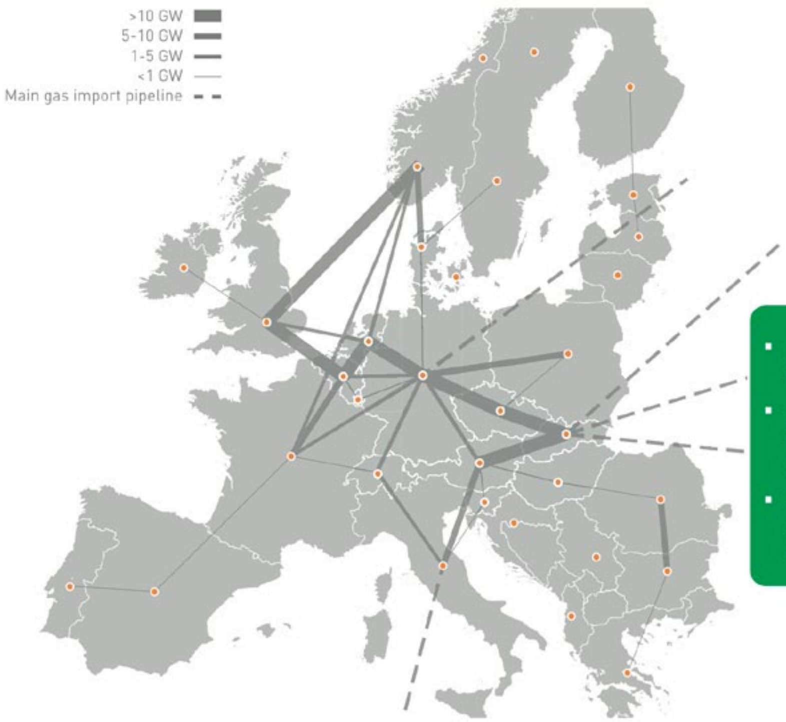


- Substantial variations in annual consumption exist at the national level
- Similar variations can be observed with regards to daily load and the maximum variation within a day
- Comparison to ENTSO-G forecasts indicates that planned infrastructure for 2020 is adequate to supply 2030 in most countries

SOURCE: KEMA; ICL, McK/EGAF analysis

ENTSO-G Capacity map data, 2011

IP firm capacity, GWh/day (Existing infrastructures)

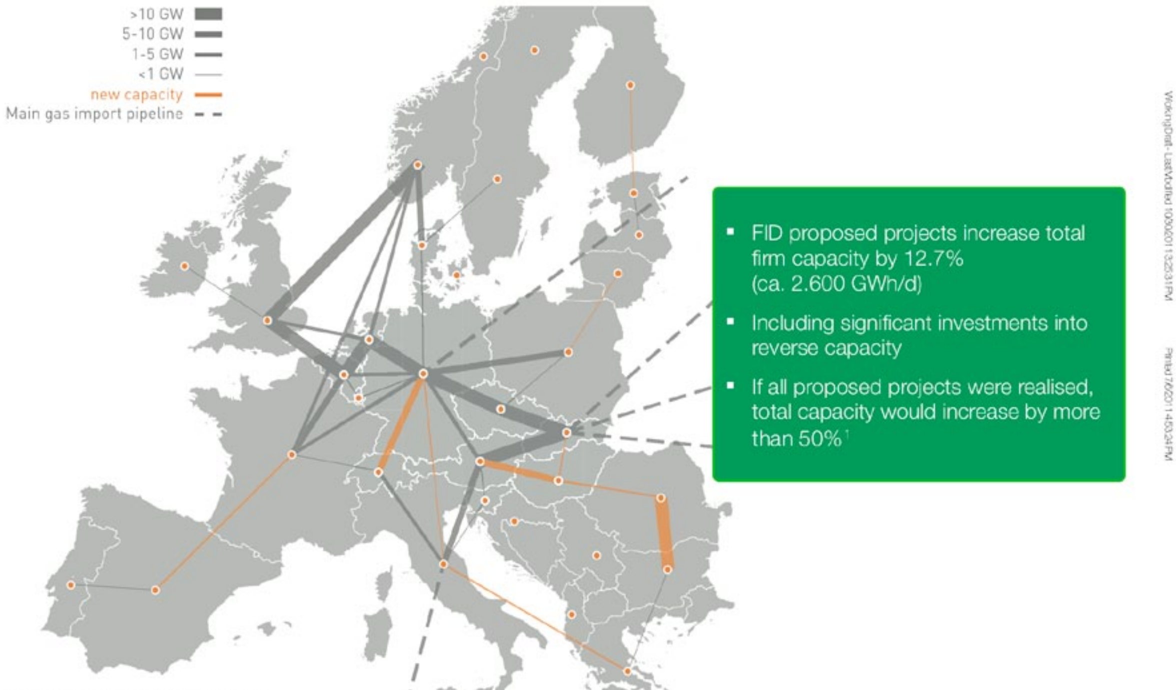


- Current infrastructure dominated by major transit pipelines
- High level of interconnection between North-Western European markets
- Note dominance of unidirectional pipelines
(limited reverse flow capabilities)

SOURCE: ENTSO-G

ENTSO-G Capacity map data, 2020

IP firm capacity, GWh/day (Existing infrastructures plus FID proposed projects)



1 Exclusive of Nabucco and South Stream

SOURCE: ENTSO-G 10-Year Network development plan

6. A CROSS-BORDER, COORDINATED VIEW OF GENERATION AND TRANSMISSION INFRASTRUCTURE DEPLOYMENT IS UNDERDEVELOPED

Currently, efforts to promote a European-wide view for the future power system are only gradually emerging. Such initiatives to increase coordination and cooperation for RES or grid development need to be seriously reinforced in order to reap the cost benefits from optimal coordination particularly for large-scale RES deployment.[63]

The most important coordination tools currently in place are:

For RES

EU climate & energy package: In 2009, the European Union adopted a binding EU target of 20% energy from renewable sources by 2020. For the power sector, this translates into ±35% of energy coming from renewable sources by 2020. The EU does not have a clear perspective on RES for 2030 despite power being a sector that demands long-term vision and planning.

NREAPs: Member States are mandated to report annually on their progress towards implementing the EU renewables target in their NREAPs. The European Commission monitors the credibility of the plans and has, together with the European Court of Justice, tools to enforce their implementation, but cannot amend the proposed energy mix – this is left as a matter of national competence.

For Grid

TSOs across Europe are mainly operating within a national perspective and most of them are still owned by the dominant generator in the country. ENTSO-E, the European Network of Transmission System Operators for Electricity, gathers all TSOs under one umbrella. It aims to enhance cooperation amongst

63 See results of analysis in p-49

TSOs for reliable operation, optimal management and sound technical evolution of the European electricity transmission system. ENTSO-E helps ensure security of supply, meets the needs of the liberalized EU Internal Energy Market and facilitates market integration.

In 2011, a new European Union body, the Agency for the Cooperation of Energy Regulators (ACER) was established following the 3rd Internal Energy Market package. ACER's mission is to assist national regulatory authorities in exercising, at Union level, the regulatory tasks that they perform in the Member States and, where necessary, to coordinate their action. This organization is not currently equipped with the full set of competences needed to represent the overarching EU perspective or to deal with the asymmetric benefits to interconnecting different regions while maximising social welfare, though this latter issue will be dealt with by forthcoming legislation.

In its 2010 communication on infrastructure[64], the European Commission set out plans to identify transmission lines of European interest and to award these lines with rapid planning and permitting procedures, as well as specific financial support. On October 19th, the Commission published a package of legislative proposals, called *"Connecting Europe Facility"*, following up their communication. The package includes a proposal for a regulation on guidelines for trans-European energy infrastructure, including a revision of the competences of ACER[65].

Despite emerging efforts at coordination, there is no binding target for grid extension nor is there a 2030 perspective for RES. Since transmission expansion and RES deployment are so closely linked, a joint mechanism or institutionalised coordination at EU level would make sense going forward.

Finally, the 3rd Internal Energy Market Package is understood not to be on track for implementation by 2014 and wholesale market reforms across the Member States are not yet consistent. This could subsequently make market integration more challenging. The implications for the power markets are covered in chapter III of this report.

64 Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network, European Commission, Brussels, 17.11.2010
65 http://ec.europa.eu/energy/infrastructure/strategy/2020_en.htm

PART C. RESOLUTIONS TO GET ON TRACK

In this section, we identify a number of aspects that are required to remain on track to decarbonisation in the decade post 2020. The analysis in this section shows that the transition will need to accelerate in the decade towards 2030. The conclusions are based on the results from the sensitivities scenarios that, compared against the *On Track case,* bring qualitative and quantitative insight into the effects of changing key elements (supply – transmission – demand) to the power system. That means that, already in this decade, the European Union needs to create the right pre-conditions to accelerate power sector decarbonisation towards 2030.

1. BUILDING NEW INFRASTRUCTURE IS THE MOST COST-EFFECTIVE WAY TO BALANCE AN INCREASINGLY DECARBONISED POWER SYSTEM

1.1 TRANSMISSION GRIDS

1.1.1. EFFECTS OF LESS TRANSMISSION BUILD-OUT

Upgrading transmission capacity and expanding the grids is a cost-effective way to keep an increasingly diversified power system balanced and robust, enabling the triple objective of integration of the European markets, RES integration and security of supply. The analysis shows the following results when the optimal degree of transmission, as represented in the *On Track case*, is stymied:

- Less transmission capacity will lead to less optimal use of resources in Europe and higher operating cost (due to more curtailment and back-up requirement). We modelled scenarios with less than optimal transmission build-out, assuming that incremental transmission capacity since 2010 is reduced by 50% compared to the *On Track case*, subject to a maximum of 5000 MW to be built at any particular border. While on average the impact across Europe on levelised cost of electricity and total cost is not dramatic, local impacts are more pronounced. In these scenarios with a reduced degree of regional integration, we observe more volatile prices in more regions and curtailment levels that increase overtime compared to the *On Track case* especially in 2030 (RES curtailment in the Less Transmission scenario increases from of 0.7% in 2020 to 2,4% in 2030 versus a stable 0.6% in the *On Track case*). In some regions, curtailment of solar and wind increases to reach levels of 10 to 25%, e.g. in Ireland, Latvia, Estonia and Denmark. On average across Europe the model observes a doubling of power production by back-up plants in 2030, leading to higher CO_2 emissions (by 30Mt CO_2e). However, the changes in opex and capex are, in combination, fairly minor. The savings to the system (due to transmission infrastructure not built) are <1% of capex over the decade 2020–2030, with cumulative opex increasing by 2.8% over the same period.

The effects become more pronounced when combining Less Transmission. In this case cumulative opex for 2020-2030 is 13% higher than in the Higher RES scenario with optimal transmission capacity. Besides, the results show a ten-fold increase to average RES curtailment levels of 7% in 2030 (equivalent to 200 TWh of production), with curtailment of wind and/or solar energy exceeding 30% of production in some countries, including Ireland, Estonia, Latvia and Spain[66]. In practice, this implies an even higher level of curtailment for some of the corresponding plants, which significantly increases the amount of investment required to achieve large-scale RES programmes[67]. These high curtailment levels occur despite a substantial increase of transport capacity of 75% over the next two decades. As a result, there is a need for an additional 40 GW of back-up generation (from 233 GW to 277 GW).

Currently, more transmission capacity and grid interconnection are the most favourable and economic options. More use of back-up may interfere with emission targets and leads to higher curtailment. Overall, the risk of stranded investments in grid is low, as these are not front-loaded and move in tandem with RES deployments. However, if adequate grid capacity is not added, RES investments risk to be under-utilised, leading to increased opex costs due to curtailment.

66 In reality, this situation could lead to a shift of RES investments to better connected locations. The model has not been designed to quantify these interactions.
67 See grid modelling details in Annex A.6 below. In case of a loss of load, an additional cost of €50,000/MWh is assumed.

Less Transmission capacity will lead to higher curtailment and back-up production, resulting in higher opex

Year	Case	Curtailment % of RES production	Back-up generation TWh	LCOE[3] €/MWh	Capex[1] Cumulative per decade, € bln	Capex change	Opex[2] Cumulative per decade, € bln	Opex change
2020	On-Track case	0.6	1	89	628	- 1%	1,645	+ 1%
	Less Transmission	0.7	1.5	89	619		1,656	
2030	On-Track case	0.5	8	86	1,153	- 1%	2,124	+ 3%
	Less Transmission	2.4	18	88	1,143		2,184	
	High RES/Less Transmission	7.0	69	n/a	1,143		2,005	
2040	On-Track case	1.0	76	n/a	1,130	- 2%	1,896	+ 5%
	Less Transmission	3.1	113	n/a	1,108		1,997	

Main assumption Less Transmission Build-out:

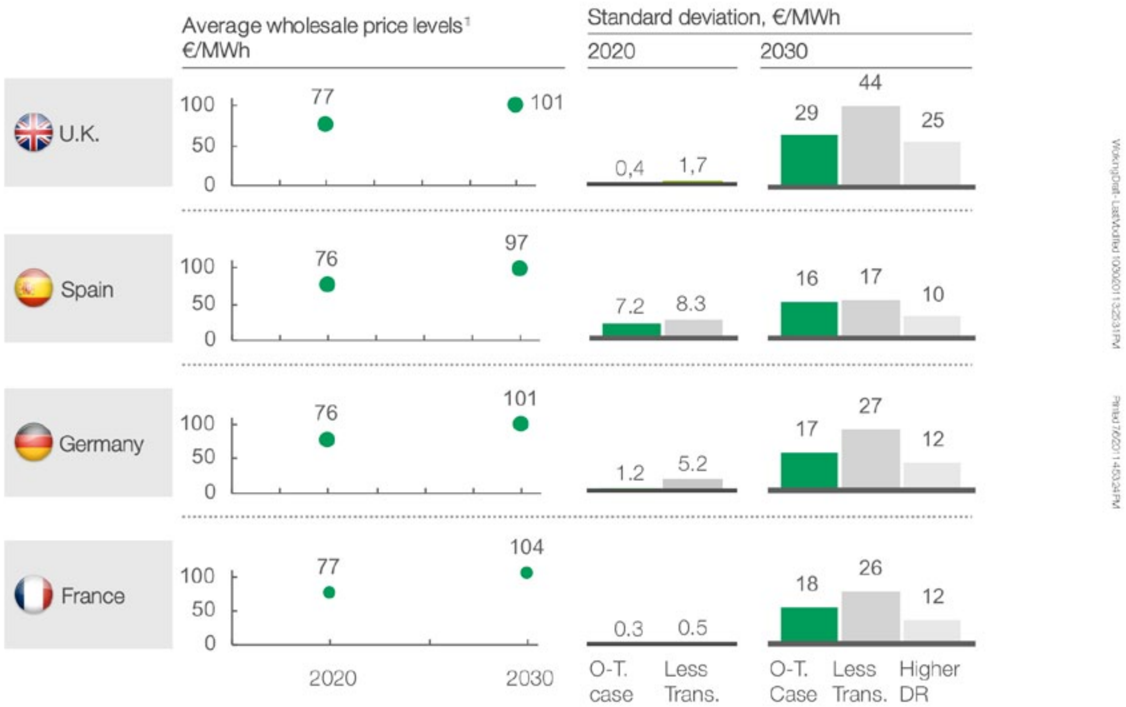
- 50% less capacity for every line built by the model in the On-TrackCase
- 2030 is subject to a maximum of 5000 MW added between 2020 and 2030

1 Capex is the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
2 Opex is for the whole system including back-up and CO2 prices
3 Levelised Cost of Electricity (LCOE) includes generation capex (incl. back-up capex) and opex of new builds (incl. back-up costs and CO2 prices) and capex of additional transmission (both onshore and offshore) build out
4 50% less capacity is only applied on the condition that this does not reduce the capacity of that line below currently available capacity
SOURCE: KEMA; Imperial College London; McKinsey

1.1.2. GRID TRANSMISSION REDUCES VOLATILITY

Another effect of expanding the grid is that it is accompanied by less volatile power prices. Price volatility in the power markets is a useful parameter to make the sector attractive to investors. However, in the Less Transmission scenario we observe very high volatility of prices as locational arbitrage opportunities emerge, a situation that has in the past led to political intervention in the market. When modelling optimal grid build-out in the *On Track case*, volatility is 30% lower. The scenario with higher Demand Response proves helpful in moderating price volatility, further reducing political risk.

Higher Demand Response is accompanied by less volatile prices, whereas Less Transmission increases the volatility



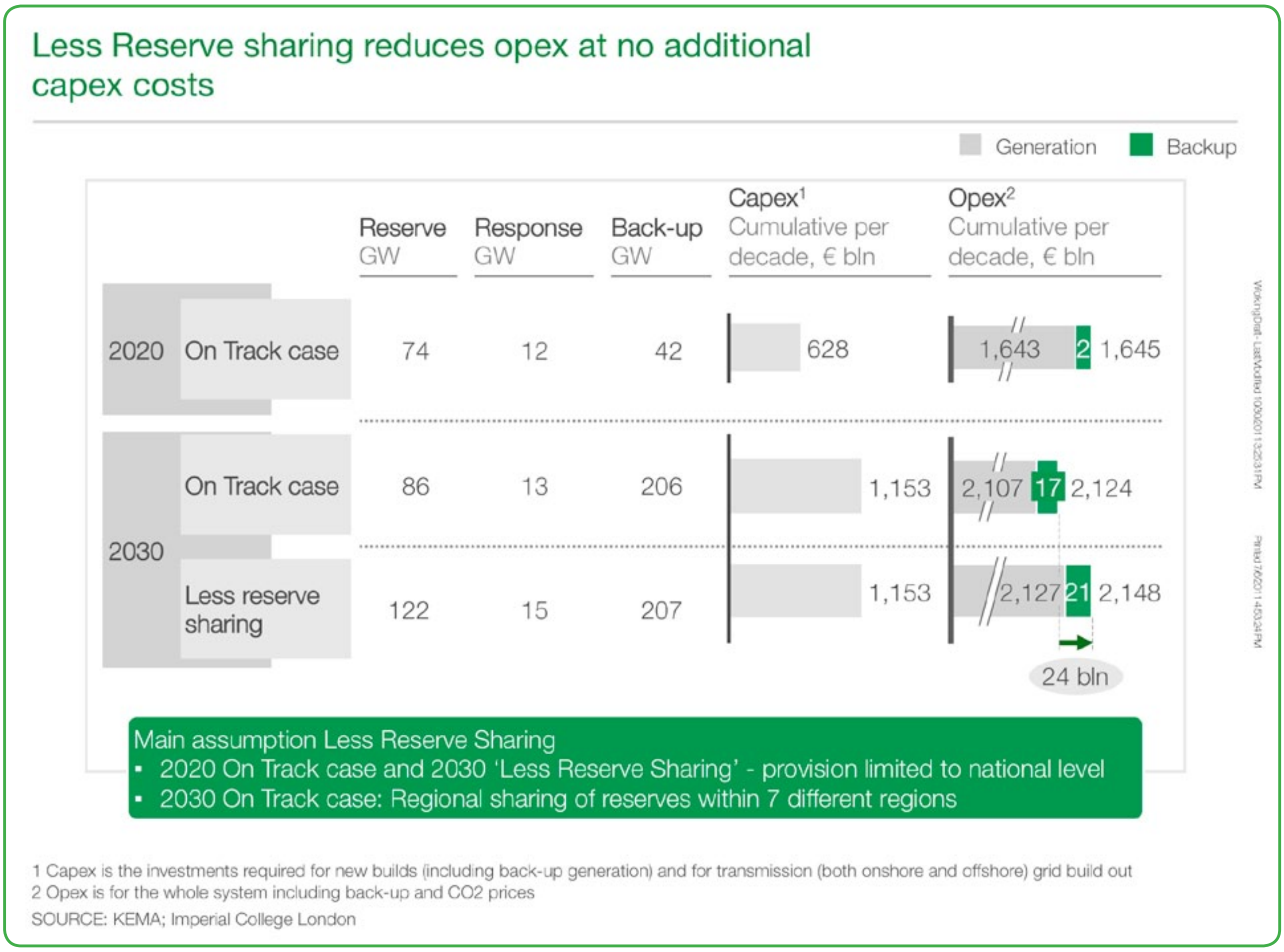
1 Load weighted average price for hours when the technology runs; Based on marginal costs; No mark ups taken into account so prices give indication, not 100% accurate; No distuingishing between sensitivities as differences fall within range of uncertainty; Prices include CO2 price;

SOURCE: Roadmap 2050 Perspective 2030 model; KEMA / ICL; tean analysis

1.1.3. GRID TRANSMISSION ENABLES SHARING OF RESERVE AND RESPONSE

Sticking to national provision of reserve and response for 2030, instead of regional sharing of operating reserves, as assumed in the *On Track case*, increases reserve requirements from 86 GW to 122 GW in 2030. Regional sharing of reserves and responses does not have any material impact on required capex (and comes only at the cost of increased coordination), but it does allow for a reduction in cumulative opex for 2020-2030 of € 24 billion. Sharing of reserve does not decrease the need for back-up generation, indicating that the required back-up capacity is driven by need for firm back-up capacity at times when there is insufficient power supply from variable renewables. However, it increases the share of back-up capacity that does not need to offer high operational flexibility, such that it can be provided by less flexible plants than e.g., new OCGT or CCGT plants.

The higher overall cost in case of less reserve and response sharing, again illustrates the cost advantages of ensuring adequate grid capacity. This will need to be supported by a continent-wide view on RES and grid infrastructure. The steep increase in the curtailment of RES in the Higher RES scenario with limited transmission furthermore shows that transmission expansion is an essential precondition for realising increasing levels of RES penetration. A structured approach to create the right incentives and responsibility for execution is necessary to lay the groundwork for future build-out of European wide grid infrastructure. Any approach will need to include a 'fair' way to pay for the grid enhancements, with similar approaches across Europe and with balanced burdens for all players involved (e.g., investors in renewable power generation, consumers, grid companies).



1.1.4 ALTERNATIVES FOR BUILDING GRID TRANSMISSION

1.1.4.1 HDVC OVERLAY GRID

Grid expansion in all scenarios is largely based on conventional AC overhead lines, without any significant use of DC technology. As occasionally suggested, it may be beneficial to construct an 'overlay grid' of extra-high voltage DC lines that functions as electricity highways facilitating the transport of large amounts of bulk power over long distances. The simulations show that an overlay grid represents a feasible and attractive option.

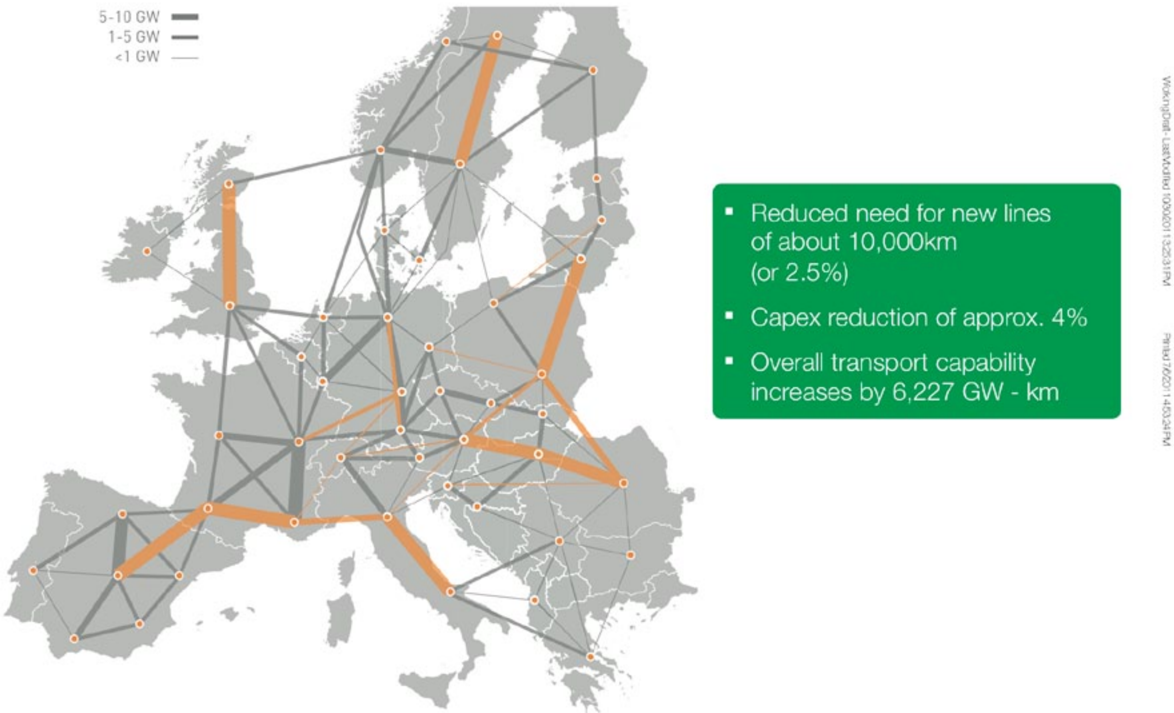
We modelled a situation where we have added the option of building 800 kV DC lines alongside the 'normal' AC-grid[68]. The possible routes were chosen along the major transport corridors identified in the *On Track case*.

This scenario shows that certain parts of this potential overlay grid would be built to replace part of the AC grid, reducing the need for 10,000 km (or 2.5%) of new lines, representing 12% less transmission projects, at the same investment levels (reduction of 4% capex).

The resulting grid infrastructure closely resembles the structure modelled in the *On Track case* and increases overall transport capability by 4.6% in terms of GW-km, but does not result in any material change in the need for back-up generation.

An 'overlay grid' of extra-high voltage DC lines would facilitate the transport of large amounts of bulk power over long distances

Transmission required
GW, 2040, Overlay grid



SOURCE: ENTSO-E; KEMA; Imperial College London

68 To ensure a cost advantage over the traditional AC grid, each component of the overlay grid typically combined two or more of the direct zone-to-zone connections (with a typical length of 1,000 – 1,500 km).

1.1.4.2. SUB-SEA CABLES

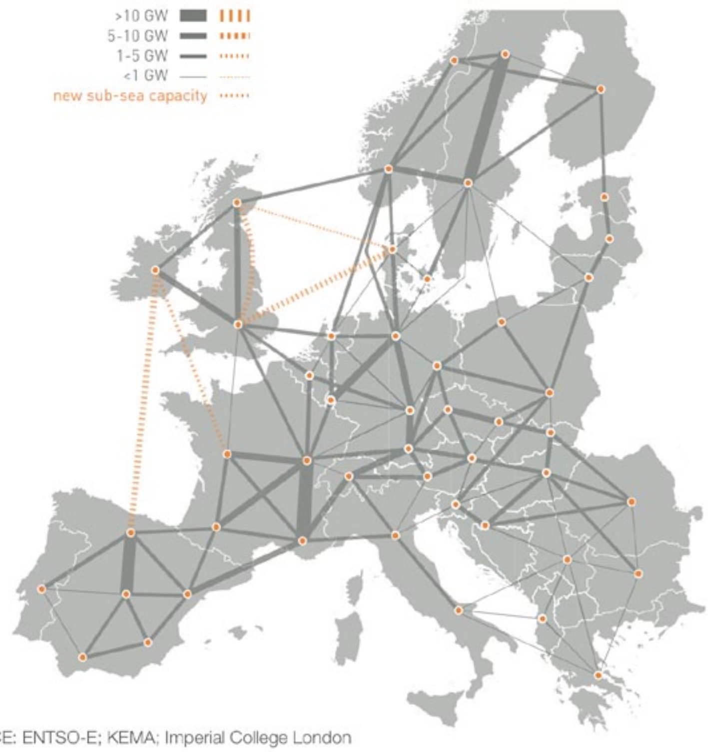
Experience to date shows that the construction of new overhead transmission lines often faces significant public opposition, regularly causing serious delays of network reinforcements. In these cases, the use of additional subsea cable may represent another alternative. We have therefore considered another scenario, built on the 2030 *Less Transmission scenario* for onshore transmission lines only. In contrast, it does not include any constraints for the construction of additional subsea DC cables. This additional scenario results in 24 submarine links being expanded by a combined capacity of 24 GW, or ~8 TW-km. The cumulative capex for transmission and back-up generation in the period 2020-2030 are virtually at the same level as in the *On Track case*, or some 9% higher than in the Less Transmission Scenario (+€11 billion). These results show that subsea cables may provide a viable alternative to onshore lines in certain areas.

1.1.4.3 OTHER OPTIONS

In the event that transmission build-out does not occur as projected, other less cost-effective alternatives such as more back-up, demand response, storage or decentralised generation will need to be explored. These alternatives range from proven to pre-commercial, and the technical challenge of deploying them should not be underestimated. Nonetheless, prudence demands to keep all options open, requiring strong continued support for the development of options such as storage innovations and new demand response technologies and strategies.

Sub-sea cables can provide an alternative in case on-shore cables face public opposition

Transmission required
GW, 2030, Less public acceptance for onshore transmission



- 24 submarine links
- Sub-sea cables expanded by a combined capacity of 24 GW or ~ 8 TW km
- Capex increase by €11 billion (+9%) increase compared to Less Transmission
- New sub-sea cables include links between North UK - West Denmark and North UK – South UK

SOURCE: ENTSO-E; KEMA; Imperial College London

1.2 LOW-CARBON GENERATION TECHNOLOGIES

As set out in the complication section, the main challenge for low-carbon generation is the required upfront investments of around 1 – 1.5tr EUR. This report has looked at ways of mitigating this challenge. As is shown later in the report, scenarios with more investments in demand side resources, like Demand Response and Energy Efficiency, prove to be effective means for reducing the required investments in generation and balancing.[69]

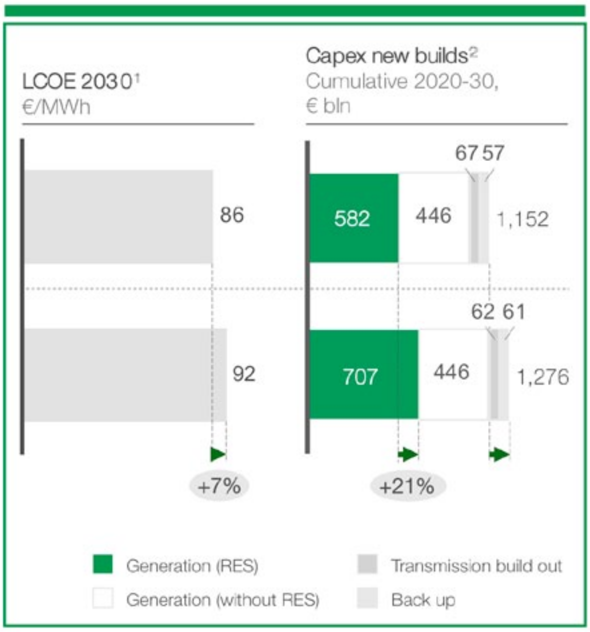
Another option to deliver substantial investment efficiencies is to take a more coordinated and integrated approach to deploying RES in locations where they are most productive. Opportunities exist to reduce required investment by expanding the scope for cross-border cooperation particularly for large-scale RES deployment, while support for distributed solutions will likely continue on a country-by-country basis. In a scenario with *Less Coordinated RES deployment*, we maintain a power mix with 50% renewables in 2030 but RES build-out is based on an allocation extrapolated from NREAPs. In some regions, this results in an increase of onshore wind capacity that exceeds the maximum potential of technologies. It also results in the expansion of solar PV at locations with lower load factors (such as Germany with 10% versus France, Italy and Spain with 12–17%). That means that more generation capacity, especially RES, is needed, which has an obvious effect on upfront investments needed. The numbers show that generation capex for renewables in 2020–2030 is 21% higher than in the *On Track case* while overall cost (LCOE) remains stable. Generation opex in this scenario is virtually identical to the *On Track case*.

Beyond 2020, a coordinated RES deployment approach results in lower cost than continued country-by-country deployment

RES deployment methodology '20-'30

Optimal coordination approach: On Track Case
- Pan European view on deployment
- Lowest cost RES technologies (based on where they are most productive) are deployed first
- Grid capacities not a constraint: output of the model

Country-by-country approach: Less optimised RES Allocation
- Countries determine own RES deployment plans
- Within the same production mix, country allocation for 2030 assumed to follow same distribution as 2020 NREAPs[2]
- If RES deployment is larger than max. assumed potential, depending on capacity above potential, load factor is adjusted downward or remaining production is allocated to other technologies or other countries[3]



1 Levelised Cost of Electricity (LCOE) includes generation capex (incl. back-up capex) and opex of new builds (incl. back-up costs and CO2 prices) and capex of additional transmission (both onshore and offshore) build out
2 Capex includes the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
3 If deployment is 100%-150% of max potential, load factor is decreased by 20%; if deployment is 150%-200% of max potential, load factor is decreased by 40%; if deployment is >200% of assumed potential, remaining capacity is allocated first to other technologies in same country, then to other countries

SOURCE: Team analysis

69 See pages 52-54

1.3 ROLE OF GAS

Gas-for-electricity will be significantly more important in the next decades; it is expected to play both a role as flexible baseload as well as back-up generator, given its relatively low capex requirements. This will be especially true in a situation with sustained moderate gas prices.

As indicated in the previous part, our analysis shows that the planned gas infrastructure will generally be sufficient to supply gas-fired power plants in all scenarios considered by this study. In some regions, however, the local infrastructure may not be able to provide the flexibility required by gas-fired turbines that are used for very short periods of time only and which may need to be ramped up within a few hours. Although these problems could possibly be resolved through investments into additional transport or storage capacity, the very low utilization of the corresponding facilities would make many of these investments highly inefficient.

In these specific cases, relying on gas-fired OCGTs for back-up capacity may not be economic. Instead, it may be more economic to use alternative fuels with local storage[70], noting that these investments would be limited to a few locations only, potentially including France and Poland. These changes are unlikely to have a material impact on investments into grid and back-up capacity. However, this could mean that market prices can be characterized by much higher peaks.

Role of gas in the decarbonisation of the power sector
The future role of gas as a supporting technology towards full power sector decarbonisation in 2050, and as a cost-effective solution to quick emission reductions in the short term is at the heart of the policy debate. The *On Track case* models a power system with continued increase of RES and, in parallel, an increase in gas-fired generation. That means that, up to 2030, a continued increase in RES does not push gas out of the system but, on the contrary, incentivises gas-fired plants while conforming with the 2030 CO_2 reduction range. Beyond 2030, CO_2 abatement goals are as such that gas can only be a significant destination fuel in the power mix if commercially deployable solutions are developed to eliminate carbon emissions.

1.4 BACK-UP AND FLEXIBLE BASELOAD

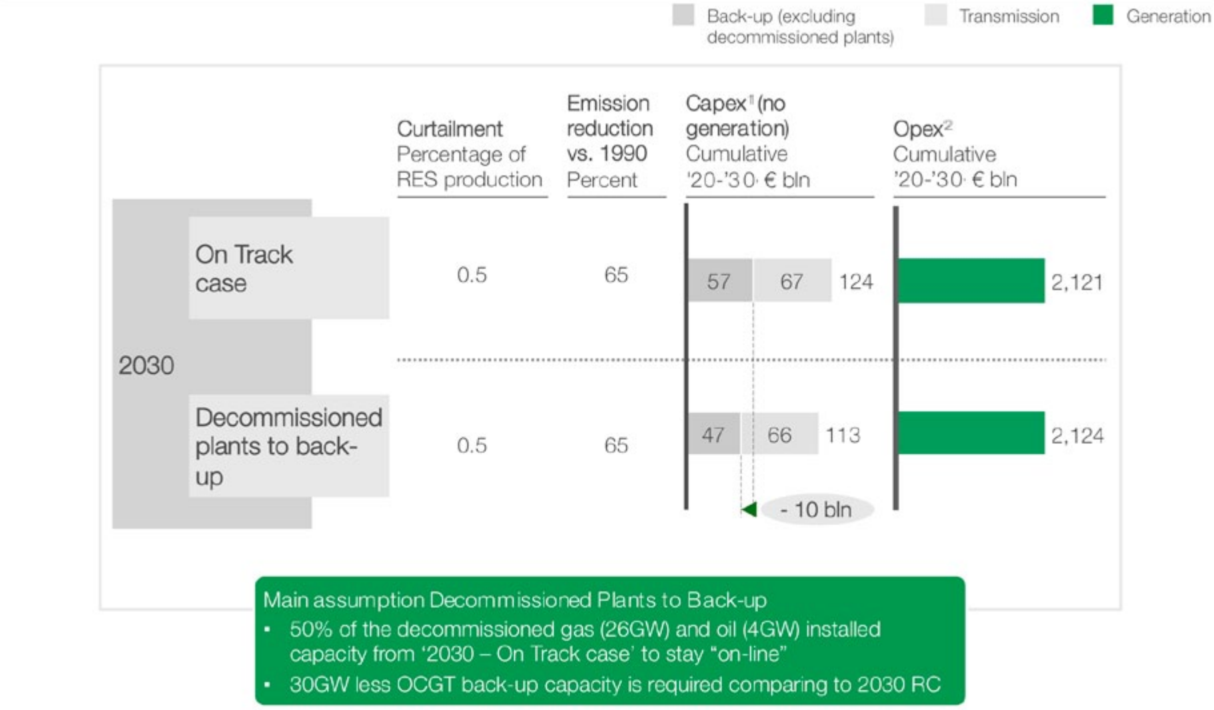
Compared to today, more back-up generation is needed to ensure supply during days when insufficient electricity from renewables is available. The variable output of some renewable technologies requires the availability of back-up capacity that can be called on to produce electricity whenever required, potentially at short timescales.

The analysis shows capacity of a total of 42 GW by 2020 and 206 GW by 2030 is needed in the *On Track case*. Almost all back-up capacity will operate less than 5% of the time and run at average low load factors (<1%), as it does today. However, with higher shares of variable RES in the power mix and constrained transmission capacity, the model sees some back-up plants run for up to 16% of the time. That means that the corresponding gas turbines do not just provide contingency reserves but increasingly become flexible baseload plans.

Even in a power system with major transmission expansion across Europe, considerable amounts of conventional generation capacity will thus be required to provide contingency reserves and provide back-up of RES on those days when renewable plants do not provide enough energy. A limited share of this capacity (though increasing with RES percentages) will have to be able to provide flexible operating reserves during the day. Conversely, some 70-80% of back-up plants provide contingency reserves (i.e. security) and could also be based on other less flexible technologies. However, these alternatives would still run at low load factors, making capital-intensive options less attractive. Apart from the construction of new plants, extending the life of existing, decommissioned thermal plants to use as back-up for the provision of contingency reserves should be explored.

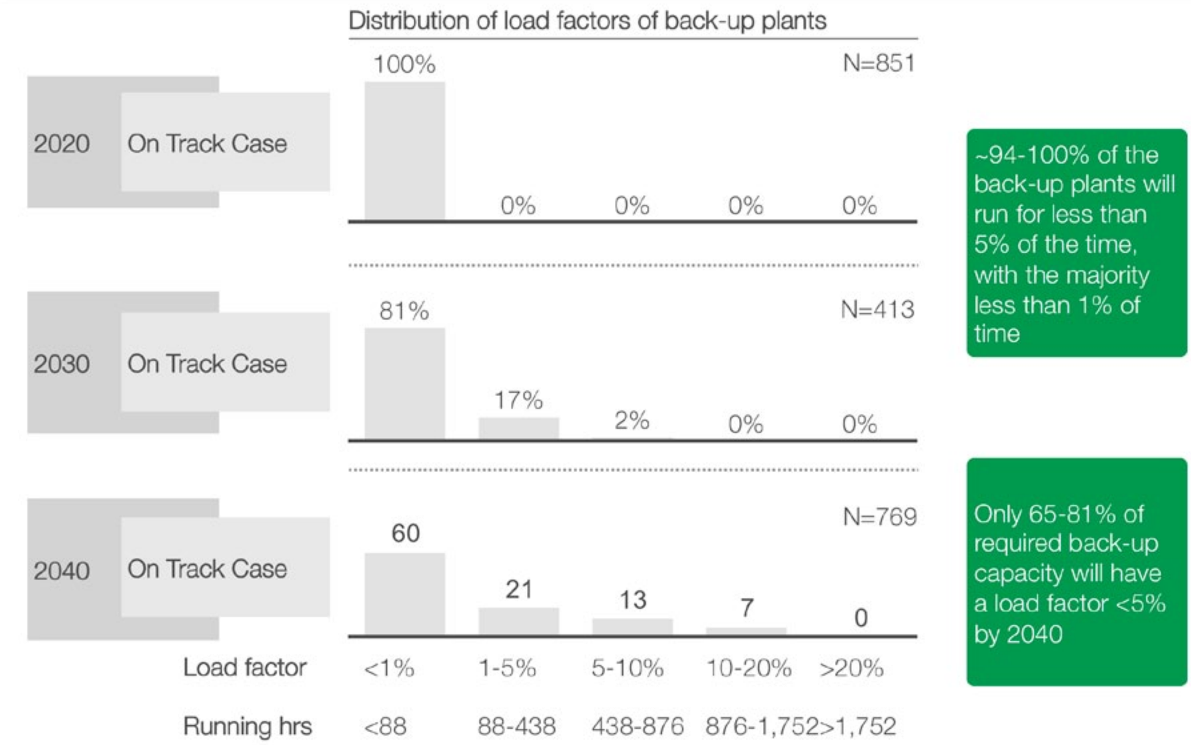
70 For example: oil-fired OCGTs with local (oil) storage . These are solutions that were beyond the scope of our study.

Other options for back-up than new built could be preferred, for example decommissioned CCGT plants



1 Capex is the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
2 Opex is for the whole system including back-up and CO2 prices
SOURCE: KEMA; Imperial College London

While running hours of additional back-up plant will be below 5% for most back-up plants, load factors increase with higher share of variable RES



1 Assuming capacity of 500 MW per plant
SOURCE: Imperial College London; McKinsey

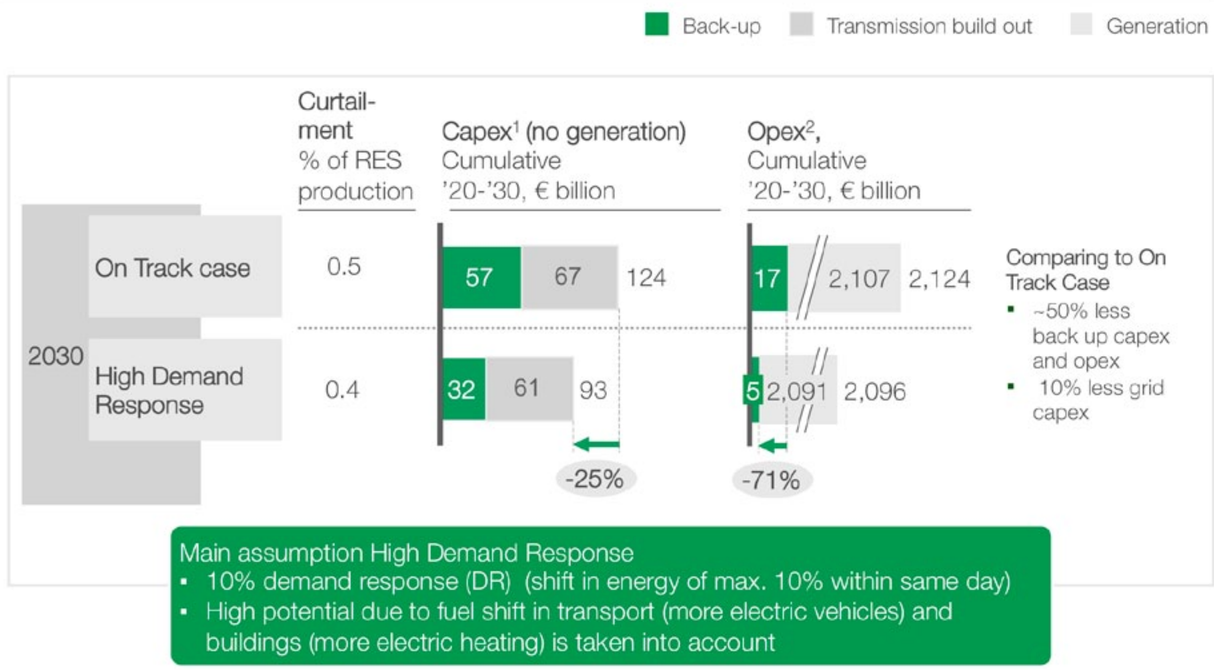
Other solutions could be explored to solve local intraday balancing challenges (especially for local bottlenecks), such as demand response, more pumped hydro in existing basins, batteries and other storage. The analysis demonstrates significant benefits from the deployment of demand response, but more work needs to be done to understand the incremental deployment cost for various demand response measures and thus their relative cost-effectiveness as a flexibility resource. Further development and cost reductions will be needed for current storage solutions to become cost-effective alternatives, but this requires more analysis beyond the scope of this study.

2. DEMAND SIDE MEASURES (DEMAND RESPONSE AND ENERGY EFFICIENCY) NEED TO BE EMPLOYED

Demand response

Demand response penetration of 10% of daily peak load[71] decreases the need for grid capacity by 10%, and backup capacity by 35%, saving respectively €7 billion and €25 billion. The EU has regulated and incentivised smart metering rollout across Europe, which is one of the key enablers for demand response. Demand response also reduces the volatility of power prices by smoothing peaks – reducing volatility by 10–30% compared to the *On Track case* and thus is shown to be an effective lever in keeping the power system robust.

High Demand Response reduces the need for back-up capacity but only slightly lowers grid investments



1 Capex is the investments required for new builds; Only backup and transmission (both onshore and offshore) capex is shown as generation capex is the same for two sensitivities

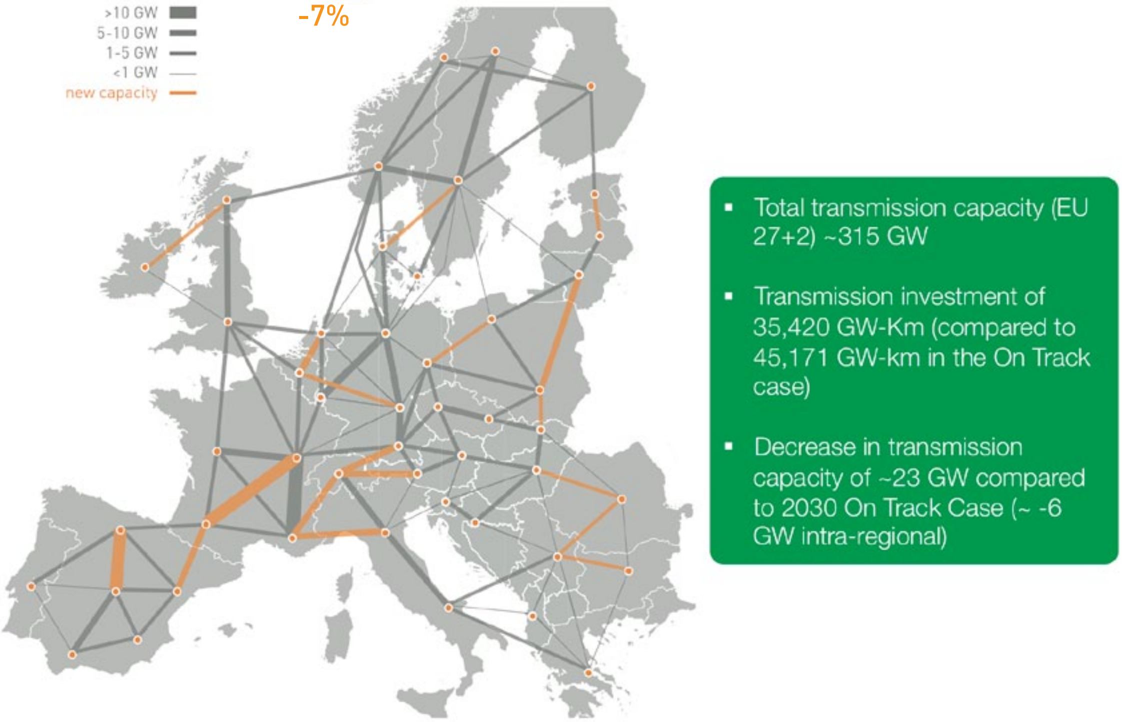
2 Opex is for the whole system including back-up and CO2 prices

SOURCE: KEMA; Imperial College London

71 The study did not include an in-depth analysis of the incremental cost to deliver the quantum of demand response assumed to be deployed in the analysis. A literature survey was conducted and suggested strongly that the level of demand response assumed (10% of daily demand shiftable to other times of the day) is well within what would be considered cost effective relative to available alternatives. This is an area deserving of further study.

The impact of Demand Response results in lower need for transmission infrastructure of ~23 GW

Transmission required
GW, 2030, Higher Demand Response



SOURCE: ENTSO-E, KEMA; Imperial College London

Although demand response represents an important instrument for helping to balance the system on a daily basis and reducing overall costs, it is not able to fully replace the need for additional transmission and back-up capacity. As several simulations with limited transmission expansion and different levels of demand response show, demand response mainly helps to reduce the need for back-up capacity but at a decreasing rate. Moreover, whilst demand response of 10% of daily peak load reduces curtailment of RES by almost 20% (from 7% to 5.8% of available energy), a further increase of demand response to 25% of daily peak load reduces curtailment of RES to 5.3% only.

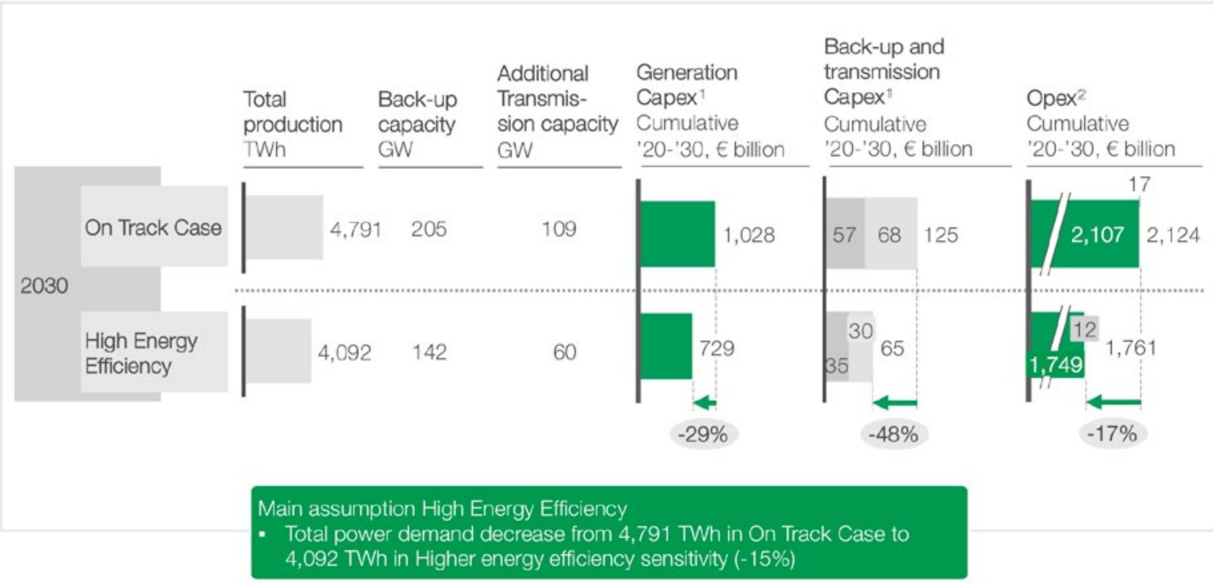
Energy efficiency[72]

An increase in energy efficiency, with a lower electricity demand of 700 TWh in 2030 (down 14%), decreases the need for grid by 55% and backup capacity by 31%, saving €299 billion in capex for generation[73].

72 Earlier ECF analysis on energy efficiency shows that: (1) A tripling of policy impact is required to meet the EU's 20% energy savings target (2) The target can be met largely through cost-effective measures, but time is of the essence (3) Closing that gap will save consumers > €100 billion per year, reduce energy import dependency, and create jobs (>1 million new local jobs across Europe by 2020) - Energy Savings 2020: how to triple the impact of energy saving policies in Europe, September 2010, http://www.roadmap2050.eu/contributing_studies

73 A study from Ecofys and Frauhofer ISI, July 2011, called "The upfront investments required to double energy savings in the European Union in 2020" found additional cost-efficient investment cost are needed in buildings, transport and Industry of around €900bn to reach the EU's 20% energy savings target.

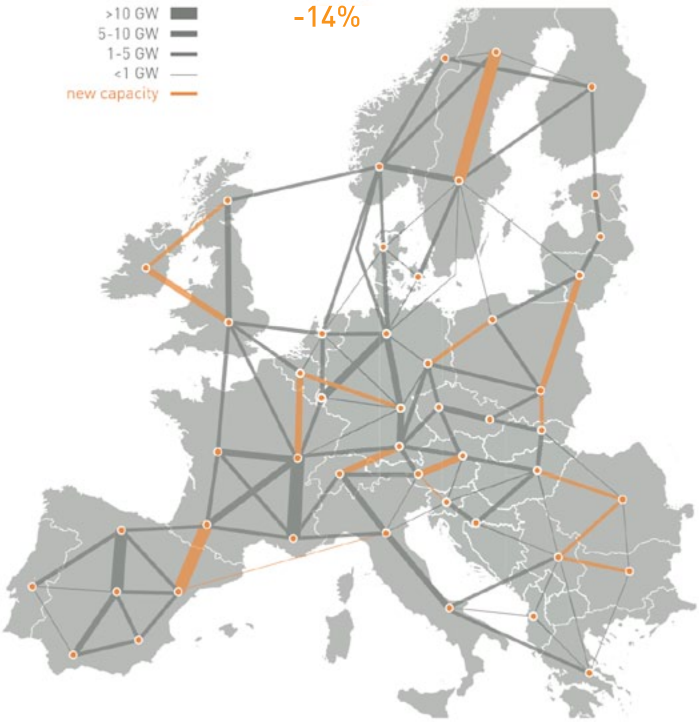
Higher Energy Efficiency reduces the need for generation investments as well as transmission and backup capacity



1 Capex is the investments required for new builds (including back-up generation) and for transmission (both onshore and offshore) grid build out
2 Opex is for the whole system including back-up and CO2 prices
SOURCE: KEMA; Imperial College London

Higher Energy Efficiency reduces need for transmission infrastructure with ~49 GW

Transmission required
GW, 2030 High EE



- Total transmission capacity (EU 27+2) ~ 289 GW
- Transmission investment of 25,772 GW-Km (compared to 45,171 GW-km in the On Track case)
- Decrease in transmission capacity of ~ 49 GW compared to 2030 On Track Case (~ -17 GW intra-regional)

SOURCE: ENTSO-E, KEMA and Imperial College Analysis

3. COMBINATION OF TECHNOLOGIES NEEDS TO BE ENCOURAGED INCLUDING FOCUSING ON R&D AND INNOVATION

It is important to promote a diverse portfolio of low-carbon generation technologies across Europe to avoid dependency on a limited range of energy sources in the decarbonisation transition.

In line with the conclusions of last year's *Roadmap 2050* report, there are risks and costs associated with ruling out technologies at this stage – whether be it a particular type of low carbon generation technology (RES, nuclear, CCS), a choice for back-up capacities (traditional back-up plant, OCGT, other less capital-intensive technologies), storage, or demand response. This implies a continued focus on R&D for a number of not-yet-established technologies as well as improvements to existing technologies.

- *Storage*: a lot of promising technologic development is happening, but on present knowledge is still a very expensive alternative (analysed in last year's *Roadmap 2050* analysis). Hence, it is hard to see how seasonal variations will be handled without grid investment or substantially bigger investments in back-up and fuel supply.

- *Distributed and decentralised solutions:* It is currently unclear what the potential is as the business case for these solutions depends largely on the local circumstances. Nevertheless, distributed and decentralised generation solutions and storage can play an important role in mitigating the grid construction challenge and, therefore, more focus on R&D and deployment will drive down the costs. Still, we recognize that the balance between centralized and decentralized solutions is not always driven only by cost and welcome further study to evaluate the relative costs and benefits of decentralized solutions.

CHAPTER III:

POWER MARKETS

PART A. CONSIDERATION – CONSIDERATIONS OF INCENTIVE/REMUNERATION REGIMES IN ADDITION TO THE NORMAL SALE OF ELECTRICITY FOR ATTRACTING APPROPRIATE INVESTMENTS TO SECURE A LOW-CARBON FUTURE

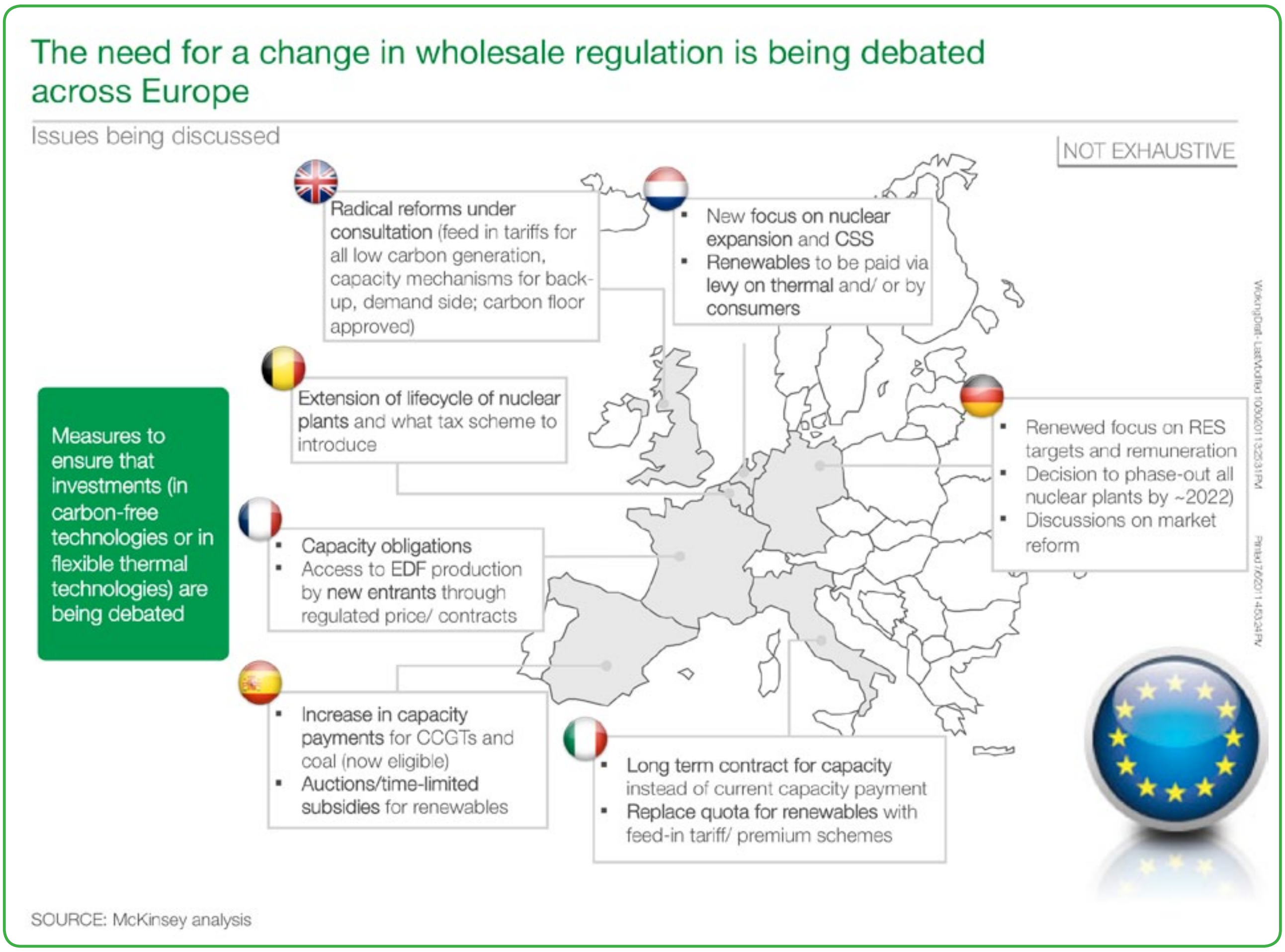
For more than twenty years (and longer in some individual Member States) the EU has pursued, and continues to pursue, a policy of liberalisation, competition and market integration in the European electricity sector. The objective of this policy framework is that a transparent, liquid and competitive pan-European electricity market will maximize economic efficiency while ensuring security of supply.[74]

More recently the EU and individual Member States have committed to significant reductions in greenhouse gas emissions, including by implication especially significant reductions from the power sector. This has both directly impacted (e.g., through the adoption of the Emissions Trading Scheme) and indirectly impacted (e.g., through the introduction of feed-in tariffs for renewables) the evolving electricity markets.

These and other interactions between the EU's emission reduction and wholesale electricity market objectives raise two fundamental questions directly relevant to the objectives of this study: What role will the electricity market play in achieving decarbonisation, and how will decarbonisation affect the evolution of the electricity market?

The following paragraphs discuss the challenges posed for various critical elements of an increasingly decarbonised power system.

74 The Internal Market in Electricity Directive 2003/54/EC addresses both wholesale and retail markets and the questions explored in this study apply equally to both. This study focused primarily on wholesale market issues and will make frequent reference to such. We recognize that competitive retail markets are essential to a functioning electricity market and that it is equally critical to align retail markets and decarbonization policy.



Grid

Most EU countries have an established regulatory framework that identifies how network operators can fund their investment program and how these investment costs are allocated to system users. However, the bases upon which investments are approved do not generally include sufficient recognition of benefits achieved beyond the respective national boundaries, and there is no accepted mechanism for coordinated grid planning on the one side, and the financing and allocation of the resulting costs to network users from different countries, on the other side. This issue is particularly relevant for interconnectors, where benefits often lie outside the country where the grid investment is required. The current regime therefore relies on investors building interconnectors on a merchant basis, relying on differences in prevailing wholesale electricity prices between two market areas – however, the basic economics of merchant interconnectors make it very unlikely that this will lead to the level of investment identified in our analysis as being required.[75]

Renewable energy sources

The principal driver of renewable development to-date has been the EU RES Directive's 2020 targets and the associated national incentive schemes. This has also enabled the development of grid build-out plans necessary to facilitate the growth in renewables. However, there are no equivalent targets that stretch beyond 2020 and, therefore, the longer-term future for renewable development is unclear.

Some RES technologies will need direct support beyond 2020 with the prospect of improvements in cost and performance, while others will arguably have reached cost parity and/or maturity by 2020 or shortly thereafter. This raises important questions about what should

75 By "merchant" we refer to transmission investments in which investors must seek recovery of and a return on their investment strictly by exploiting market opportunities rather than through any form of allowed pass-through of costs and risks to consumers; it is this assumption of "merchant" risk that acts to constrain its potential.

come after the 2020 targets have been met. Should the deployment of technologies be left to “the market plus ETS” once they’ve reached cost parity or maturity (whichever comes first)? Cost parity, however, is but one factor affecting whether a class of resources can or should be required to “sink or swim” in the market as it’s currently conceived. Variable resources, for instance, are inherently disadvantaged by the current suite of market revenue opportunities even after having reached cost parity, since spot prices (which are the primary driver of revenues received by generators in the market) tend to be low when variable RES is experiencing high utilization and high when RES utilization is low. Another important consideration is the risk mitigation value in a more balanced low-carbon resource portfolio in 2030 than the market-plus-ETS might otherwise produce, given the significant technology and supply security risks inherent in all of the technology pathways to decarbonisation we’ve examined.

RES incentive schemes such as Feed-in-Tariff or Green Certificate schemes (providing a premium or top-up to wholesale price revenues) have enabled the EU to take a lead in RES deployment. However, in some cases incentive schemes have undergone multiple revisions (adversely impacting investors as well as the supply chain); been inefficient (overcompensating investors at the expense of consumers or taxpayers); been ineffective (under-compensating investors; overly complex or risky); or were not adequately structured to drive innovation and capture the related cost reductions. Experience now exists on how to design effective and stable support mechanisms that are robust to the risk of political revisions, however that experience has yet to be fully incorporated across various Member States approaches.

With current levels of variable RES penetration incremental operational requirements, such as hourly balancing and provision of operating reserves, have been absorbed by the system As penetration has continued to expand, however, the operational issues have expanded as well. There is a growing need to make these issues more transparent, address them in a cost-efficient manner and establish an equitable approach to allocating the associated costs across all relevant stakeholders.

New nuclear

The risks and costs associated with nuclear, discussed earlier, are such that new nuclear projects are not likely to attract investment on a merchant basis as sought by certain Member States governments. Some initial thought is being given in some Member States to support mechanisms tailored specifically to nuclear projects, while in other Member States the focus is on public acceptance and the extent to which nuclear power should be part of the future power mix at all.

CCS

CCS is an early-stage technology with significant potential for cost and performance improvement but significant challenges as well. The likelihood of significant new investment in gas-fired generation highlights the urgency of developing commercially viable CCS technology, as does the importance of CCS to abatement of heavy industry. Given the associated costs and risks, governments will need to take a positive decision to support these technologies and develop an appropriate delivery mechanism for the wider deployment. Some initial thought is being given to such mechanisms in some Member States, while in other Member States the focus is on public acceptance.

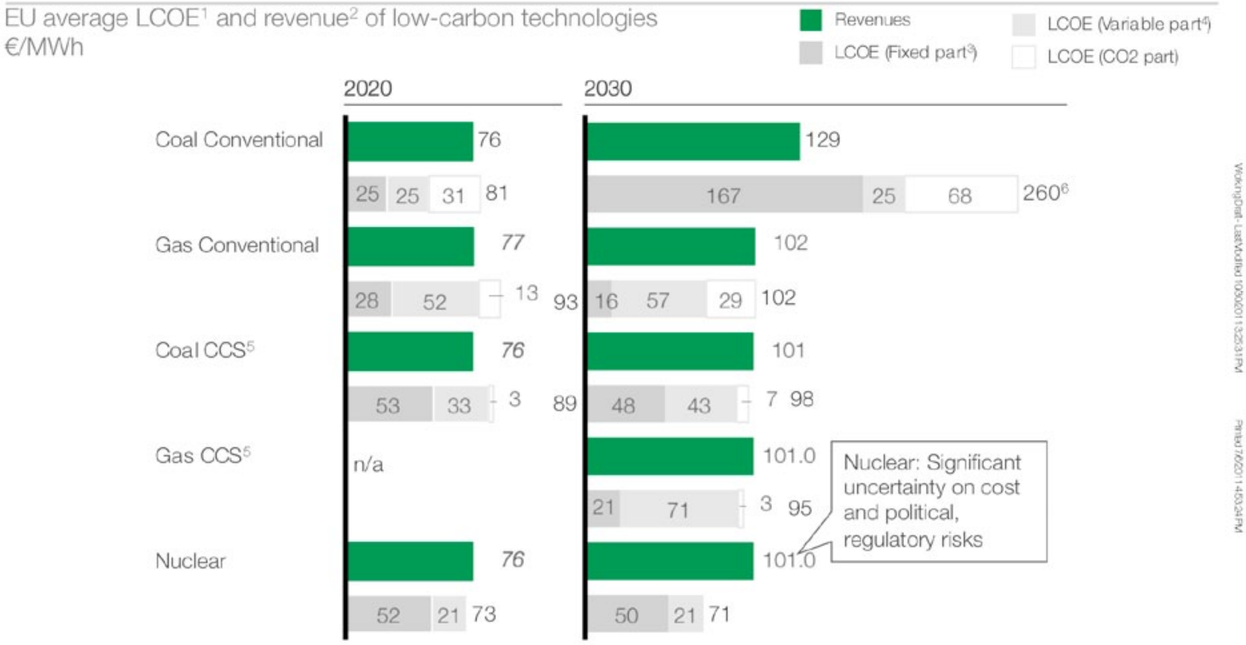
Conventional thermal technologies

Conventional thermal resources will continue to play a role in ensuring affordable and reliable electricity as the system decarbonizes. It is broadly assumed that competitive wholesale markets should continue to be the primary driver of new investment in this segment as well as underpin the commercial viability of those existing assets that continue to be of value to the market. Yet there are valid reasons to examine these assumptions more critically, as discussed below.

The growing share of low-marginal-cost variable resources in the supply mix will transform the operating environment for thermal resources. These resources may experience lower annual utilization rates, or the pattern of utilization within the year may become more variable and less predictable. Some stakeholders have postulated that the very fact of a much higher share of very low marginal cost resources will drive average energy prices below the levels required to recoup investment, while increased shares of variable production will bring excessive price volatility. The combined impact of these concerns – low operating hours, chronically low prices, high price volatility – were they to materialise, could have the potential to undermine the ability of the current wholesale market framework to attract sufficient investment at an acceptable cost. Our analysis did not provide support for this conclusion, however it did identify increased investor risk in some dimensions[76].

There is also a related question of the optimum mix of conventional resources that will be required as decarbonisation progresses. As the share of variable RES grows, the space in the market for resources technically and/or commercially incapable of frequent and significant changes in production (i.e., traditional non-flexible "baseload" plant) will gradually compress. Conversely, the need will grow for resources capable of operating efficiently and reliably with more frequent upward and downward changes in production. There will also be an increasing need for resources that can survive commercially despite long periods of inactivity interrupted by brief periods of steady-state operation. It is therefore important to consider whether the current market revenue models will direct sufficient new investment to those resources with the desired attributes. In responding to that concern, it is equally important to consider whether measures to promote the development of new resources (e.g., proposed capacity mechanisms) are adding to or perpetuating a surplus of resources lacking the needed attributes while not increasing the quantum of resources with the needed attributes.

It is unclear whether conventional non-RES baseload technologies will recover cover their full costs



1 Levelised Cost of Electricity (LCOE) based on load factor from ICL/KEMA model reflecting average for existing and new builds
2 Load weighted average price for hours when the technology runs; prices based on marginal costs, No markups due to security pricing taken into account; Prices include CO2 price
3 Fixed part contains investments and fixed maintenance costs
4 Variable part includes fuel, variable maintenance, and CCS storage cost
5 There are no Gas CCS plants build in 2020 and only limited demo capacity for Coal CCS
6 LCOE of coal is significantly higher in 2030 due to low load factor of 11% compared to 77% in 2020. The low load factor is an output of the 2-step modeling approach of (1) setting generation capacity and (2) subsequent grid modeling, shifting production to other sources than coal, due to high CO2 prices in 2030

SOURCE: KEMA; Imperial College London; McKinsey

76 See below on page 64: Our analysis of market prices relies on a number of critical assumptions, including inter alia: (1) the grid is expanded as needed and in a timely manner; (2) real-time integration of resources through the wholesale energy market is realized over a sufficiently large area; (3) full competition is supported by transparent and liquid trading in the products and services required by all market participants; (4) investors develop sufficient confidence that the ETS will sustain at least the CO2 prices assumed; and (5) as generating resources are added to the market via schemes such as those described above, a healthy balance is maintained between demand for generating resources of various types and the supply of those resources.

Demand response and energy efficiency

The cost of decarbonisation could be significantly reduced through the use of demand side resources (including demand response and demand reduction). However, traditional market designs have had only modest success in bringing forward investment. This is for a number of reasons:

- Traditional sources of demand response are equated with deprivation, seen as appropriate only in extraordinary circumstances and as clumsy and unreliable resources for system operators; market opportunities (or the lack thereof) continue to be shaped by this perception.

- The same illiquidity that threatens long-lived supply-side investments presents a hurdle for demand-side resources, but there is an added barrier in the fact that markets remain poorly defined for the kinds of system services that will increasingly be in demand and that demand-response in particular may be well-suited to provide.

- Demand side investments do not always receive access to the same level of value (including subsidy) available to supply sides resources.

- Market arrangements have usually been designed with supply side cost and risk structure in mind rather than those on the demand side.

- Opportunities and requirements for market access have traditionally been administratively demanding and costly and thus favor large supply-side companies over smaller and diffuse demand-side actors.

PART B. MODIFICATIONS - MODIFICATIONS TO INCENTIVE MECHANISMS FOR DIFFERENT PARTS OF THE POWER SYSTEM WILL BE REQUIRED IN VARYING MEASURES

The results of the analysis performed here offer some guidance in addressing the issues identified above, however it must be emphasized that the issues are often complex and values-laden and do not necessarily lend themselves to quantitative analysis alone.

The over-arching market challenge posed by the analysis is the capital intensity of the available solutions – the economics of meeting the twin objectives of supply security and decarbonisation are manageable but require upfront capital investment to be balanced against life-cycle savings in fuel, operating and externalities costs.

Whether or not the required quantum of investment will be forthcoming is in essence a matter of striking a balance amongst investor risks, the cost of capital, social interests and the economic efficiency of the expected outcomes. Where possible this should be accomplished through incremental and coordinated improvements to existing arrangements – existing market frameworks and the existing scope of regulation – rather than through more radical changes in policy direction, which by their nature can often increase risk and delay necessary action. The following recommendations are made with this in mind.

The focus of this analysis was on the requirements to deliver reliability under a range of interim conditions at 2030. The *On Track case* for the analysis assumed that 50% of electricity comes from a diverse portfolio of RES in 2030 (versus ~35% in 2020), from which we derived a range of other scenarios. While we did not set out to map an ETS-driven, market-based, least-cost pathway to 2030, we did in last year's *Roadmap 2050* report examine a range of outcomes running from "minimum RES" (implying little growth in RES share of market post-2020) to "high RES" (RES is added to the system through 2030 at a rate consistent with an 80% RES power system by 2050). While it is possible, perhaps even likely, that a pure "ETS plus market" model would produce something like the "minimum RES" scenario, it is also apparent that this scenario implies a disproportionate concentration of risk exposure to commercialization of fossil-with-CCS at very large scale by 2030 and/or a large and sustained expansion of nuclear power. European energy policy has traditionally viewed risk mitigation and cost minimization as equally important objectives. Furthermore, the European Commission has outlined an emissions reduction trajectory for the power sector indicating around 60% CO2 emissions reductions by 2030 as an important interim milestone in its climate and energy objectives, a level of abatement the "minimum RES" scenario in last year's *Roadmap 2050* report is unlikely to deliver. Therefore whilst a range of pathways to 2030 are technically possible, we derive the following observations on markets from the analysis on the principle that more rather than less resource diversification through to 2030, including a diverse portfolio of RES technologies, is most consistent with the EU's energy security and decarbonisation objectives both in 2030 and beyond.

Grid

One of the clearest conclusions from the analysis is that a large expansion of the existing grid (as proposed by ENTSO-E through 2020 and then continuing at an accelerated rate through 2030) is a cost-effective and critical component of any solution to both the supply security and the decarbonisation challenges. Not only is a more robust grid required, but the architecture of the grid will also need to evolve to facilitate a significant increase in cross-regional exchange of resources of all types.

Grid build-out plans are based on an expectation of the future geographic distribution of resources, and conversely the future development of resources will to a significant extent be determined by the size and shape of the grid. Given that build times for transmission can be much longer than for generation resources, a clear long term view on the amount and locations of low carbon resources (beyond 2020) is important to ensure that sufficient grid capacity is built and in appropriate configurations to facilitate most efficiently the resources (both supply-side and demand-side) expected to be developed.

This will require an increased level of coordination among Member States in long-term grid planning. ENTSO-E has made good progress on long-range system-wide grid planning and facilitating coordination between the different areas of the European grid. ACER is ramping up its capabilities to ensure the proposal and implementation of TSOs' national ten year network development plans are consistent with the Community-wide network development plan, remove obstacles to cross-border energy trade and generally complement national energy regulators with an EU-level regulatory oversight. However the progress made by these institutions in this regard has yet to be matched by a similar level of coordinated cross-border action at the Member States level necessary to implement the plans.

Planning will be of little value without similarly effective processes for cross-border cooperation on cost/benefit allocation and compatibility of regulatory regimes between Member States. This aspect of grid expansion is lagging far behind planning, yet without it investment will not be forthcoming. Merchant transmission is likely to play an important but very limited role, and while there has been some suggestion of EU funding for strategic network projects the reality is that this is likely to cover at best only a small fraction of what is required. What is needed to attract investment at the required scale are multi-state processes empowered by the affected Member States to (i) assess the regional benefits of proposed projects, (ii) agree an equitable allocation of the associated costs among all affected stakeholders, and (iii) implement the agreements[77]. For this to succeed a common framework is needed for congestion management across the EU.

77 There are several examples of such cooperation happening today, amongst others: the Baltic Energy Market Interconnection Plan (BEMIP), North Sea Countries Off-shore Grid Initiative (NSCOGI),

RES

It is expected, based on the legislated 2020 targets, that ~35% of electricity will come from various RES technologies by 2020. This analysis, considered alongside last year's *Roadmap 2050* report, suggests a prudent risk diversification requires that the shares of supply from a diverse portfolio of RES continue to grow beyond their expected 2020 market shares. When viewed in the context of recent developments on new nuclear and CCS a pathway that includes continued deployment of a diverse porfolio of renewables appears essential to ensure that Europe is on track for power sector decarbonisation.

The recent prospect of significant new sources of economic natural gas supplies can be beneficial in many ways to power sector decarbonisation between today and 2030, however it also illustrates why a sustained rate of RES deployment cannot be taken for granted, even with the impact of the ETS. Dedicated support for RES deployment will continue to be crucial to lowering investment uncertainties created by the dynamics of the market. A stronger and more durable ETS with a reduction factor that is consistent with the 2030 and 2050 abatement targets can play a very important role as well by properly pricing externalities and thereby reducing dependency on direct subsidies. A combination of new RES deployment targets beyond 2020 with a strengthening of the ETS consistent with the 2030 and 2050 targets is therefore necessary to ensure the investment case for continued deployment of a portfolio of promising RES technologies through 2030.

Whilst continued support for RES deployment beyond 2020 is important, it is equally important that the support schemes are crafted in ways that optimise the economic efficiency of the wholesale market process. RES deployment policies must be adapted to drive cost improvements more aggressively and capture those improvements in subsequent procurement rounds. Based on recent experience, options include a transition to periodic auctioning of new RES contracts; degressive tariffs (i.e., tariffs with a pre-determined downward evolution); or review at intervals to incorporate cost reductions into the tariff structure. Particular applications would depend on the commercial scale of the technology and how well established the technology is and how competitive the supply side is.

Appropriate application of existing support schemes is dependent on the maturity of the technology/market

	Pros	Cons	
Regulated tariffs – fixed evolution	▪ Stable and predict-able : guaranteed investment in entry capacity and lower cost of capital ▪ Easy to implement	▪ Cost is not optimized – Learning curves are not accounted for, so will be sub-optimal towards the end of the period compensation Difficult to set the tariff a priori ▪ Difficult to promote convergence to competitive market	Adequate for initial periods or immature technologies/ markets, to ensure investment in new capacity
Regulated tariffs – degressive evolution	▪ Cost is slightly more optimized, as the system can benefit from the tech-nologies' learning curves (flexibility and ability to react) ▪ Natural convergence to the market	▪ Possible difficulty in reaching elevated levels of capacity growth – lack of certainty for investors ▪ Difficult for regulators to measure future efficiency	Appropriate for immature tech-nologies/markets where the focus is on efficiency
Auctions	▪ Maximum efficiency ▪ Natural convergence to the market	▪ Lack of visibility on real costs in early stage markets can cause investor uncertainty ▪ Ineffective as a tool for achieving objectives at a required rate.	Appropriate for mature markets with some cost visibility for investors / operators

SOURCE: Team analysis

The analysis in page 49 already indicated a decrease in investment requirements beyond 2020 when planning optimal allocation of RES across Europe. Member States will continue to have an interest in developing indigenous resources, but by 2020 RES penetration is expected to reach the level where an equal emphasis will need to be placed on sourcing from the most economic providers and ensuring greater compatibility of support schemes between markets.

RES generation will increasingly need to assume operational responsibilities in the market commensurate with their emerging role as major system resources. Yet as was the case with the introduction of nuclear power beginning in the 1960s, the juxtaposition of legacy resources with this new class of resources gives rise to complex operational challenges and associated system investments, the locus of responsibility for which is not as obvious as it may at first appear.[78] Market arrangements must be adapted to address this in the most cost-effective manner possible; market participants must have not only the responsibility to meet reasonable operational obligations but also a reasonable opportunity to hedge the associated risks (see next bullet). Issues such as the size of balancing areas, the time periods for system balancing, gate closure and cash-out arrangements and the frequency of resource forecasting should be examined and brought up to date uniformly across Europe to ensure that markets are not incurring unnecessary costs. A single actor – one without conflicting commercial interests, presumably the designated system operator – must retain single-point responsibility for enforcing reliability standards in each respective balancing area.

Integration of RES will be facilitated by, and will give rise to, a significant increase in the role of what have traditionally been referred to as “ancillary services”, a range of functions required to ensure the system remains in balance in all places at all times. While such functions have always been critical, they have historically constituted only a small fraction of the total economic activity within the wholesale market. The analysis indicates that is likely to change. Electricity market frameworks will need to evolve in response to this growing demand in ways that balance economic efficiency with system reliability. The effectiveness and efficiency of markets for such services will be a critical factor in addressing the operational challenges identified in the foregoing paragraph. Various alternatives exist to address these challenges, including storage, demand response, flexible supply options and contingency reserves. Allocating investment amongst these alternatives through competitive services markets would drive innovation and maximize cost-effectiveness. Exhibit 46 goes more in-depth on this topic and presents one possible approach in the form of “capability-based” market instruments.

New nuclear

Where Member States have made the decision to include new nuclear supply in their resource strategies, the financial community have long maintained that they will not invest in nuclear on a merchant basis (i.e., relying on the wholesale energy market for recovery of their investment) and therefore technology-specific support schemes will likely be required, as is the case with deployment support for RES. There are important differences: nuclear is added in large blocks with very long lead times and it is a mature industry. For these reasons the design features recommended to drive RES cost reductions – for instance the periodic auctioning of long-term contracts for successive tranches of supply – will be of limited use. Mechanisms specifically suited to nuclear projects (such as nuclear-specific contracts-for-difference or nuclear feed-in tariffs) could be considered. As with RES support schemes, tariff risk and volume risk would be transferred to consumers while completion cost, completion schedule and operational performance risks should remain with investors.

CCS

CCS possesses the scale and lead-time attributes of nuclear but the technology development risks associated with pre-commercial RES technologies. Also, unlike nuclear or RES, applications for CCS outside of the power industry will likely be at least as important

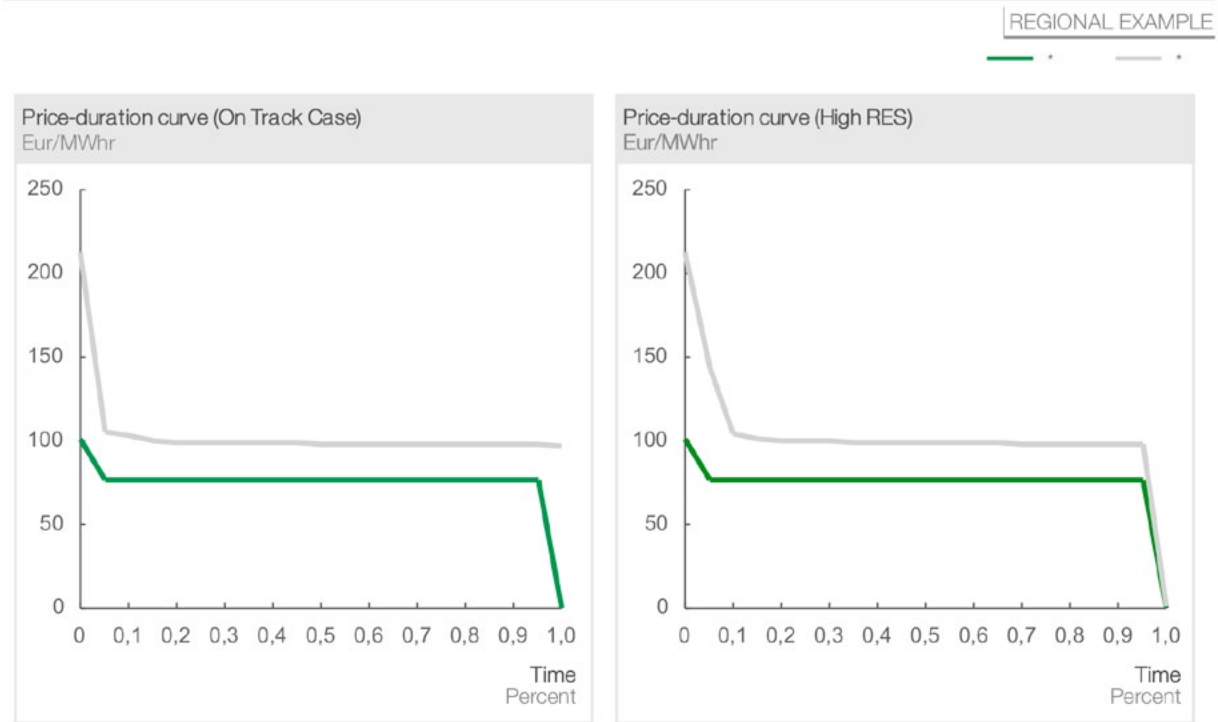
78 The decision to move in a significant way to nuclear power in the 1960s and 1970s introduced large quantities of low-marginal-cost, operationally inflexible and in many cases remotely located capacity into a system that had not been designed to accommodate it, resulting in the need for significant investments designed to allow the nuclear fleet to operate around the clock, including pumped storage hydroelectric facilities, distributed thermal storage systems, expanded power grids, etc. In nearly every case these integration costs were socialized.

as power industry applications. Finally, since natural gas-fired generation will likely play a critical transitional role between now and 2030, the nature of its role beyond 2030 is contingent on the commercialsation of CCS. CCS therefore occupies a unique position in the decarbonisation challenge and requires specific forms of development and deployment support in order to advance its commercial viability in the period beyond 2020.

Conventional thermal resources

Our analysis of market prices relies on a number of critical assumptions, including *inter alia*: (1) the grid is expanded as needed and in a timely manner; (2) real-time integration of resources through the wholesale energy market is realized over a sufficiently large area; (3) full competition is supported by transparent and liquid trading in the products and services required by all market participants; (4) investors develop sufficient confidence that the ETS will sustain at least the CO2 prices we've assumed; and (5) as generating resources are added to the market via schemes such as those described above, a healthy balance is maintained between demand for generating resources of various types and the supply of those resources.

Only in a well-integrated and interconnected power system, price is set by conventional technologies for most of the time



SOURCE: ICL model

Our analysis finds no support for the theory that a large share of near-zero marginal cost resources in the supply portfolio would necessarily, in and of itself, collapse wholesale energy prices to chronically low levels.[79] As the share of RES (and other must-run low-carbon resources) grows through 2030 and assuming energy markets are well-integrated, wholesale prices over time continue to reflect, on average, roughly the total cost of generating resources on the system, including a return of and a reasonable return on invested capital.

The analysis on market price volatility, discussed in the section 1.1 on transmission grid and RES does provide support for the proposition that wholesale market prices are likely to become more volatile as the share of variable RES (and, if applicable, the share of nuclear) grows as expected. If the assumptions listed above prove false then the level of volatility is likely to increase. It also appears likely, though the analysis is less granular in this regard, that the less flexible the fleet of conventional resources the more volatile prices are likely to be. Adding pumped storage hydro capacity can increase flexibility and moderate price volatility.

Wholesale price volatility is a normal feature of a healthy commodity market. There is, however, a risk that the expected increase in volatility increases the potential for unwarranted political intervention to "protect" consumers or if it affects certain classes of resources more acutely than others and, in so doing, gives rise to an uneconomic increase in investor risk. The analysis points to particular concerns in this regard with the class of resources often referred to as "back-up" – generators expected to be called upon only infrequently, during periods of acute shortage of energy in the system. These resources play an important role in ensuring not only reliability, but also the economic viability of the balance of system resources in a functioning wholesale electricity market.

Therefore while the analysis suggests that wholesale prices could remain fully remunerative of the required quantum of conventional thermal resources, the analysis neither proves nor disproves the proposition that there is a threshold difference in the risks associated with these investments as decarbonisation progresses – risk that the measures outlined in point above do not materialize as required, or that volatility increases as described above. Investor behavior is always difficult to predict with confidence but particularly so under such dynamic circumstances.

Some Member States, and some markets outside of Europe, have amended their wholesale market frameworks by adding mechanisms such as forward capacity markets or capacity payments in an anticipatory effort to bolster investor confidence; other jurisdictions are considering similar measures. It would be wise to weigh carefully the considerable amount of experience to date with such measures. Capacity markets may or may not provide a more robust investor case for investment in new capacity or for retention of existing capacity (the jury is still out), but capacity alone (the ability to produce energy) is often not an adequate description of what is needed.

While all capacity has the ability to produce energy, different types of capacity provide the system with different capabilities, including not only energy production but also the *option* to produce energy under certain circumstances and in certain ways (e.g. how fast spinning or non-spinning reserves provided by an OCGT or CCGT can be brought online). Each of these capabilities has a different value in ensuring reliability, and our analysis (e.g., at section 1.3), suggests that relative values of the various attributes conventional resources are capable of providing will evolve considerably as decarbonisation progresses. There are current examples of systems with capacity mechanisms having excess capacity but a shortage of resources capable of providing certain essential reliability services.[80] A capacity market is of limited value in this situation and may actually be counterproductive. We discuss below a range of potential capacity mechanisms and their suitability.

79 Some may point to recent experience in markets such as Spain, Northern Germany and ERCOT's West Zone as evidence that the opposite is true; the analysis here suggests that the reasons for the periods of very low prices experienced in those markets may lie elsewhere, and indeed in each of those cases data suggest the cause is simply a market that is oversupplied with firm, inflexible capacity. Surplus installed capacity is a structural feature of future markets, which means the flexibility of non-intermittent capacity (and demand) must increase to avoid chronic over-supply problems.

80 Capacity payment mechanisms can be quantity based (such as those in New England, PJM, Western Australia and Greece); or price based (such as in Ireland, Spain, Italy, and Chile).

Wholesale markets – Alternative models for adapting energy markets to optimise investment risk

	Mechanism	Description	Suitability
Capacity-based market instruments	i Quantity-driven procurement mechanisms	▪ Auctioning of rights to term fixed payments to meet planned capacity needs ▪ Desired quantity is predetermined and price is set by the marginal clearing bid. ▪ Typically takes the form of supplier obligations administered & enforced by system operator ▪ Can be comprehensive (covering all system capacity) or targeted (contracting for only specified types of capacity, e.g., peakers) ▪ Designed to set a single value for all capacity that meets the stipulated requirements	▪ Can be applied to new and/or existing plants as well as demand side resources ▪ Best suited to placing a single system-wide value on the target commodity (typically firm capacity value) ▪ Targeted auctions tend to distort the market and exacerbate investment risk ▪ Not well suited to systems with high shares of variable resources where capacity value is highly differentiated ▪ Vulnerable to political intervention
	ii Price-driven procurement mechanisms	▪ Similar to (i) but value of capacity is set administratively, typically ex post for subsequent periods ▪ The quantity procured is then a function of the price established	▪ Limited experience to date ▪ More easily adapted to differentiate the value of various capacity resources ▪ Central administrative role in setting price raises issues of economic efficiency ▪ More vulnerable to political intervention
Capability-based market instruments	iii Auction market for resource services	▪ Auction-based term procurement of capacity services such as back-up, responsive reserve, non-spinning reserve, ramping, regulation ▪ System-wide values established for capacity services rather than for capacity itself ▪ Most likely based around supplier obligations	▪ Applicable to all supply-side and demand-side resources – applies differentiated values to capacity resources by design ▪ Administrative setting of types and quantities of resources may give greater certainty but may also reduce efficiency
	iv Bilateral markets in resource services	▪ Similar to (iii) but quantity and price are set by bilateral trading ▪ Quantity and price are a function of the market exposure to the cost of imbalance ▪ System operator enforces reliability standards and plays a back-stop role	▪ Improves efficiency and opens market to wider range of risk management tools ▪ Less vulnerable to political intervention ▪ Question about ensuring adequate liquidity in longer-term instruments and credit quality ▪ Need to limit system operator's free-rider risk

SOURCE: Team analysis

If governments conclude, therefore, that reliance on the wholesale energy market alone presents too great a risk of underinvestment in conventional resources, then in considering amendments to the market structure the focus should be on assigning a system-wide value to specific services resources can provide, rather than on assigning a single undifferentiated value to all firm capacity resources on the system. Adoption of capacity-based mechanisms without a high degree of cross-border coordination carries a high risk of frustrating market integration; the inherent adaptability and compatibility of capabilities-based mechanisms with existing energy markets substantially reduces that risk.

Demand response and energy efficiency

The analysis on demand response and energy efficiency has affirmed the significant value of both demand response and energy efficiency to supply security and decarbonisation. The roles that demand response and energy efficiency play in the analysis are very different and will be valued in very different ways by the market.

Energy efficiency is largely a baseload resource and was found to be very valuable in reducing the cost of decarbonisation. Markets can be used to elicit some portion of investment in cost-effective efficiency measures, and indeed most existing capacity markets allow the demand side to bid as a resource[81]. The question of market failures and energy efficiency is dealt with in other studies and was not a focus of this study.

Demand response is largely a flexibility resource. The analysis affirmed the findings of last year's *Roadmap 2050* report and indeed found that demand response has even greater potential to reduce the cost of decarbonisation while improving security of supply. New

81 For example in the PJM capacity market in the US, where participation in the demand -side now accounts for more than $500 million per year in revenue to the participants. In ISO-NE's fifth Forward Capacity Auction (for the 2014/2015 commitment period), 1,384 MW of active real-time demand response resources cleared the auction, accounting for $47 million per year in revenue to these participants. Real-time demand response resources filled 4% of the auction's net installed capacity requirement of 33,200 MW.

and more controllable options for demand response are emerging, including distributed energy storage options such as electric water heaters that are often grouped under the rubric of demand response. Markets, as discussed above, should ensure these options (offered either by individual consumers or through aggregators) have full and equal access in order to determine their true value and incentivise investment.

Just as demand response is a viable alternative to storage and flexible supply, so those options represent an alternative means to provide the system with the growing need for flexibility and ancillary services. Each of these options should receive equal consideration in the market.

CONCLUSIONS

There are no simple choices. Transparency and information will be of decisive importance in driving broad public, political and commercial support for the transformation. The debate on the EU's energy future has for a long time been blurred by over-simplified analysis, partly based on presenting future options as current realities. The ambition of *Power Perspectives 2030* has been to analyse what needs to happen in the coming twenty years based on today's knowledge of the options and the choices still before us.

To a large extent, the transition to a decarbonised power system is about investments. Whether or not the required level of investment will be forthcoming is in essence a matter of striking a balance between investor risk, the cost of capital, social interests and the economic efficiency of the expected outcomes. Where possible this should be accomplished through coordinated and incremental improvements to existing market arrangements but it is unlikely to happen without governments exerting significant influence on the framework for investments made by market players over a longer time period. The overall challenge is to run a step-wise transformation and gradually build a stronger platform to reach the 2050 end-goal.

PowerePerspectives 2030 shows that to remain on track to achieve the 2020 and 2050 energy and climate objectives, existing National Renewable Energy Action Plans, ENTSO-E grid plans and carbon pricing taken together represent a sound and adequate first step and the EU and its Member States must first fully implement them, with sufficient emphasis on public acceptance and financing. This is clearly a challenging task and appropriate measures must be taken to ensure that all stakeholders involved can and will realise these plans. Meanwhile, policy-makers, regulators and market actors must work together to create the right pre-conditions to accelerate decarbonisation towards 2030. Important prerequisites are to ensure regulatory certainty and clarity for investors; build public acceptance; incentives for TSOs; finance, and relevant planning instruments. Already in the current decade, a stronger sense of direction towards 2030 is needed to support investments and enable markets to support the transition to a decarbonised power sector.

Hence, a stable policy & legal framework for 2030 is required, adapted to the scale and nature of the challenges:

1. **Building new and improved transmission grid infrastructure is essential to balance a decarbonised power system cost-effective** and to integrate energy markets. Beyond 2020, the lowest cost solution calls for twice as much additional grid capacitydas compared to the planned expansion in the current decade. Lower levels of grid expansion are also feasible but involve trade-offs with higher levels of capital investment, greater price volatility and higher diverse RES curtailment.

2. **It is important to promote a diverse portfolio of low-carbon generation technologies across Europe**, including wind, solar, hydro, geothermal, biomass and other promising low-carbon option, to avoid dependency on a limited range of energy sources in the decarbonisation transition. **Then complementarity of renewables deployment and flexible thermal generation is central to that approach.**

3. To ensure this diversification, **a perspective for renewable technologies beyond 2020 is required at the European level.** As diverse RES shares in the power mix increase beyond 2020, cross-border cooperation between Member States on planning and implementation provides opportunities to significantly reduce capital investments.

4. Adaptations to the power and carbon markets should be considered to underpin investor confidence in the transition and **steer investment to an adequate mix of resources that are technically compatible.** Traditional capacity-based mechanisms will become increasingly unfit for purpose assneeds shift from simple firm capacity to the particular capabilities a resource offers to the system, such as flexibility.

5. **Demand-side resources such as energy efficiency and demand response (including distributed energy storage options and distributed production) represent an attractive means** to reduce the amount of transmission and large-scale generation investments required. Power markets need to promote energy efficiency, demand response, storage (large-scale and distributed), distributed generation and efficiency as system resources on an equal basis with utility-scale supply options.

6. **To keep the CCS option viable both for coal and gas installations,** more needs to be done to drive technology development and demonstration, and gain public support.

7. A physically and commercially integrated European electricity market combined with greater compatibility among national regulatory frameworks and a sufficiently restrictive carbon regime provide the foundation for achieving established GHG abatement objectives affordably, reliably and securely. **However, progress on market integration is lagging and the current ETS linear reduction factor of 1.74% needs to be adjusted to align with the 2050 target of 80% domestic GHG abatement.**

8. *Power Perspectives 2030* clearly identifies some daunting challenges to remain on track to decarbonisation. It is therefore essential for policy makers to provide the right signals and incentives to all players in the value chain as soon and as clearly as possible. As shown in last year's *Roadmap 2050* report, any delay of action will only increase the overall cost and will impose significant stress on the power system. *Power Perspectives 2030* therefore calls upon policy makers on both European and national level to take appropriate action up to and beyond 2020 to remain on track to the 2050 decarbonisation goals.

APPENDIX

A. METHODOLOGY

A.1. KEY ASSUMPTIONS AND CONSISTENCY WITH ROADMAP 2050

As a general rule, we have applied the assumptions from *Roadmap 2050* consistently in *Power Perspectives 2030*. These assumptions had been syndicated in-depth throughout last year with a wide group of stakeholders (companies, NGOs, think tanks, academics, etc). However, in some case we have changed the assumption in those cases where either (1) the numbers were outdated, or (2) the figures were not granular enough for a projection exercise.

Key inputs and assumptions (as stated in Chapter 1) and changes compared to *Roadmap 2050* are:

Projection versus back casting: the analysis models current plans up to 2020 and further projects a power mix in 2030 in line with the emission reduction trajectory for the power sector in the European Commission's 8th March 2011 communication.

Geographical scope: EU-27 plus Norway and Switzerland, as in *Roadmap 2050*. For grid modelling purposes in *Power Perspective 2030*, some small countries are added (Bosnia, Herzegovina, Croatia, Montenegro, Macedonia, Serbia, Kosovo and Albania). Moreover some large countries are divided into several regions (Austria, Czech Republic, Italy, Norway, Sweden, Germany, UK, Spain and France). *Power Perspectives 2030* does not look at integrating generation from areas outside Europe (e.g., North Africa, Turkey, Ukraine, Iceland, etc.).

Power demand is an input based on the Reference scenario in PRIMES report "EU energy trends to 2030" (2009, assuming the 20% energy saving target is met), and adjusted upwards to reflect electrification from transport, industry and heating sectors based on *Roadmap 2050* estimates. We do not include extra Energy Efficiency measures as modelled in *Roadmap 2050* in the *On Track case* in Power Perspectives 2030.

Production mix in 2030 is built by the model, and not back-cast as in *Roadmap 2050*. Up to 2020 both capacity and production are based on NREAPs. There are no adjustments for any potential reductions due to implementation challenges on these plans. Beyond 2020 the modelling of the EU-27 production mix uses this 2020 RES deployment pattern as a starting point leading to a share of 50% in the *On Track case* and 60% in the Higher RES scenario. The technologies used in the production mix are only those at commercial stage development. Different from *Roadmap 2050,* we now also assume gas-with-CCS (25% of all gas-fired installations by 2030). Like *Roadmap 2050,* the production mix is an exogenous input to the grid model, and is not constructed by fuel or CO_2 price assumptions.

CO_2 emission reduction for the power sector in 2030: Ths report closely follows the European Commission emission reduction trajectory of ±60% in the power sector by 2030 in light of full decarbonisation by 2050[82].

ETS and carbon prices: the carbon prices used are €38/ton for 2020 and €85/ton for 2030 and beyond, based on IEA WEO 2009 - 450 scenario[83]. The fuel and carbon price assumptions are used in the KEMA/ICL hour-by-hour dispatch model, influencing the dispatch of technologies based on short-run marginal costs. The carbon price is not a variable in the model and hence does not reflect the trading nature of the ETS.

82 COM(2011) 112, A Roadmap for moving to a competitive low carbon economy in 2050, http://eurlex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0112:FIN:EN:PDF

83 http://www.iea.org/textbase/npsum/weo2009sum.pdf

We have assumed that the linear reduction factor in the EU Emissions Trading Scheme Directive (number of allowances) is adjusted from 1,74% to at least 2,5% so to be in line with 2050 GHG abatement goal.

Fuel prices are updated according to IEA WEO 2009, same as in *Roadmap 2050*

Transmission grid is modelled with a granularity of 48 nodes across Europe (compared to 9 in *Roadmap 2050*). Reliability assumptions are the same as in *Roadmap 2050* (99.97%). All numbers on transmission infrastructure include off-shore wind connections, unless stated otherwise.

A.2. OVERVIEW OF SENSITIVITY SCENARIOS

On Track case – This is the main scenario. It is based on the full implementation of the existing renewable and grid plans up to 2020 and further projects a power production mix towards 2030 in line with the emission reduction trajectory in the European Commisson's communication (range of -54 and -68% in 2030). That means that, for 2020, the power production consists of 35% RES (of which 15% variable), 25% nuclear and 40% fossil (of which 25% unabated gas). Towards 2030, this report opted for a production mix with 50% renewable energy source (of which 30% variable), 17% nuclear and 34% fossil fuels (of which 18% unabated gas) across Europe. While we recognise that there are other ways to achieve the mid-term CO2 reduction range, this report considers alternatives as less likely, due to, on the one hand, acceptance issues with new nuclear build and, on the other hand, the unavailability of large-scale commercialisation of CCS before 2030. An alternative pathway relying heavily on gas concentrates deployment risk to only a few technologies and carries a higher risk of locking Europe's power sector into a GHG emitting generation capacity fleet with little clarity on further abatement potential as required beyond 2030.

- The *On Track case* does not assume any demand response. This is addressed in the sensitivity scenario modelled.
- The *On Track case* was constructed at the beginning of the project, before the Fukushima-Daitchii nuclear accident and hence does not fully take into account the changed political aspirations on nuclear in several Member States. The ECF and consultants believe the objective of our report, to identify the challenges and present solutions to remain on track to power sector decarbonisation in 2030, is not jeopardised by this. In addition, the sensitivity scenario with less nuclear and CCS does reflect this new situation.

Several sensitivity scenarios are designed in such a way that they bring qualitative and quantitative insight into the effects of changing key elements to the robustness of the power system, compared against the *On Track case* up to 2030.

Higher RES – This scenario models 60% renewables in 2030 as an input in the model. We have continued this trend into 2040 leading to 70% RES in the overall mix to stress test the scenario and to support the findings on LCOE and price evolutions.

Less nuclear and CCS - This scenario models a 2030 power mix with no new nuclear built post-2020 and no commercial deployment of CCS infrastructure beyond the planned demonstration plants. Moreover accelerated retirement of nuclear was assumed (10% less existing capacity by 2030). This scenario was constructed to reflect public opposition to certain low-carbon technologies, especially in the aftermath of the Fukushima Daiichi nuclear disaster. The new power mix is 57% RES (35% variable), 9% nuclear and 34% fossil (of which 32% unabated gas installations)

Less Transmission - This scenario assumes a 50% undershooting of ENTSO-E plans and reflects the assumption that less transmission than the current ENTSO-E plans suggest will be built. Since this undershooting will have a more systemic impact on the pathway to decarbonisation, we have further extrapolated a lower transmission build-out also in time perspective 2030 and 2040 to test the effects. We have also stress-tested low transmission build-out against the Higher RES scenario. In addition, and to reflect potential public opposition to on-shore grid build-out projects, we have modified the 2030 Less

Transmission scenario without constraints for a number of subsea DC cables.

Less Coordinated RES Deployment - This scenario extrapolates the trends in the 2020 NREAPs towards the time perspective 2030. That means that, although the same overall RES input is assumed as in the 2030 *On Track case*, the generation mix is based on the country-lead RES deployment in line with current trends up to 2020.

Less Reserve Sharing - This scenario changes an important assumption in the *On Track case* that reserve and response capacity will be shared amongst neighbouring countries as of 2030 on regional level. In this scenario, we do not assume any reserve sharing beyond the country borders.

Higher Energy Efficiency - This scenario interpolates the demand curve that we used in *Roadmap 2050,* including more aggressive efficiency assumptions in buildings and industry. This is different to the *On Track case* demand projection, which follows the continued annual efficiency rates that lead to the implementation of the 2020 energy savings target. In this scenario, power demand increases by 0.3% pa from 2020 to 2030 (compared to 1.8% pa growth in the *On Track case*). This results in 15% less power demand in 2030 in the higher energy efficiency scenario when compared to the *On Track case.*

Higher Demand Response - This scenario models a 10% of demand response capacity, e.g., to shave-off-and-shift peak demand later in the day. The 10% potential is based on a gradual increase of heat pump and electric vehicles, and is line with linear growth of the DR potential of 20% as modelled in *Roadmap 2050* (almost 0% level today, 5% in 2020, 10% in 2030)[84]

Decommissioned plants as back-up - This scenario assumes that 50% of the decommissioned gas and oil installed capacity from the 2030 *On Track case* are repurposed to stay on as back-up installations.

For the *On Track case* and some scenarios (e.g., Less Transmission), we have continued the extrapolation of current trends into 2040 in order to give perspective to some key challenges in the decades after 2030 and ensure we are on the way to full decarbonisation by 2050 in 2030. In addition, we compared the benefits of an overlay grid in comparison to strengthening the full grid in 2040.

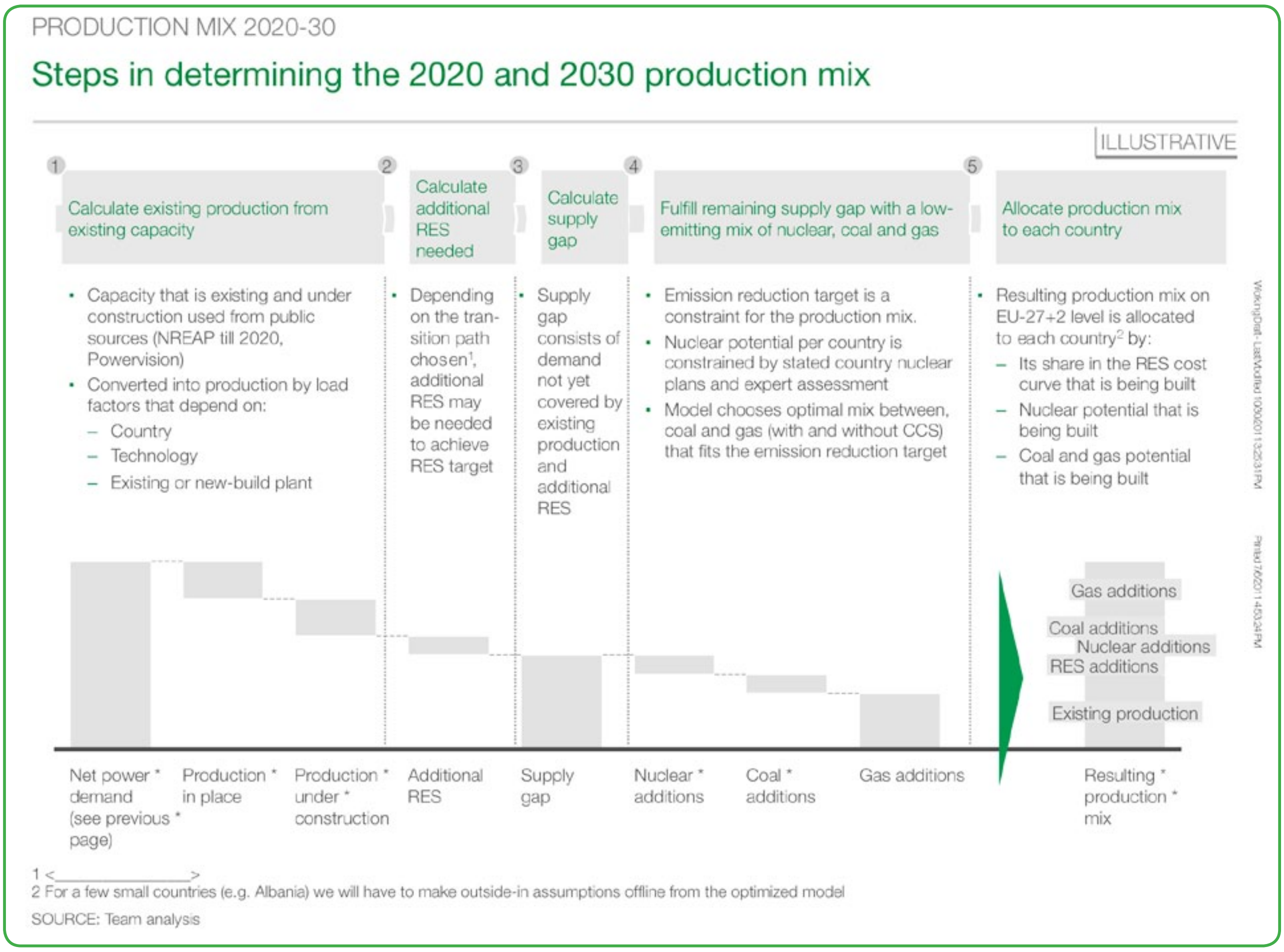
Overlay grid 2040 - This models the alternative of direct long-distance lines or electricity highways. We added the option of building 800 kV DC lines alongside the traditional AC-grid[85]. The possible routes were chosen along the major transport corridors identified in the *On Track case*.

84 To enable demand response and active demand management, upfront investment is needed in enabling technology such as smart meters, as well as for reinforcing and upgrading the distribution grid more broadly. This study has not modelled the distribution side – nor therefore quantified the investment requirements for demand response.

85 To ensure a cost advantage over the traditional AC grid, each component of the overlay grid typically combined two or more of the direct zone-to-zone connections (with a typical length of 1000 – 1500 km). For cost estimations please see: JRC, 'Smart Grid projects in Europe: lessons learned and current developments" – page 17, http://setis.ec.europa.eu/newsroom-items-folder/electricity-grids, June 2011

A.3. GENERATION MIX METHODOLOGY

The generation mix is defined based on the set-up shown here:



Power demand, capacity, production, LCOE, capex and emissions are defined based on a set of inputs and assumptions (e.g. total European demand, existing capacity in place and technological parameters) and calculations (e.g. supply gap and cost of electricity).

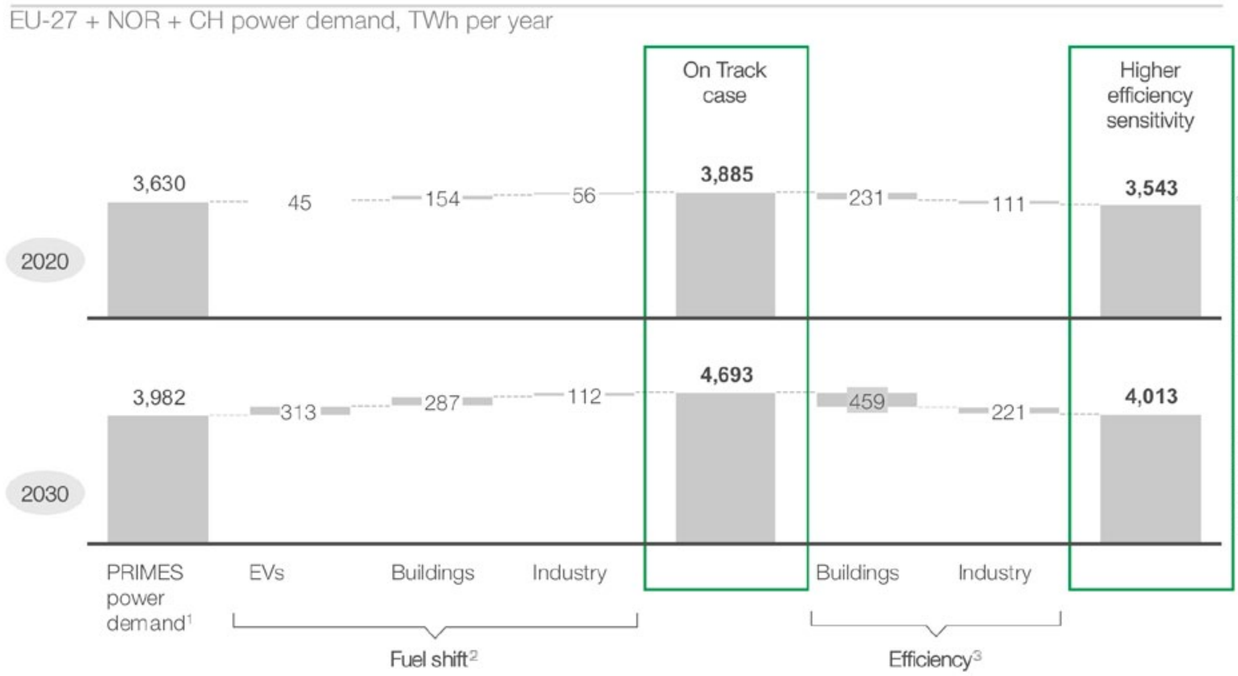
Demand

Power demand is based on the Reference scenario (including policies for 20-20-20 targets) in PRIMES report "EU energy trends to 2030" (updated in 2009) and is adjusted upwards reflecting electrification from other sectors. These fuel shifts for 2020 and 2030 are both based on backcasting from the *Roadmap 2050* estimates. Electric vehicles increase exponentially, buildings and industry (heat pumps) linearly. Fuel shifts have been allocated to each country by share in EU car fleet (electric vehicles) and share in EU industrial and residential fossil fuel demand (heat pumps). The demand in the Higher Energy Efficiency scenario is based on linear backcasting from *Roadmap 2050* estimates for 2050 as explained above.

Production mix - Key assumptions and constraints

The technologies used in the production mix are limited to commercially available technologies as in *Roadmap 2050*. Ocean/tidal/wave energy is added in category "Other RES", because this technology is included in the NREAPs of some countries.

PRIMES 2009 data adjusted for fuel shift and efficiency



1 Based on Reference scenario (including policies for 20-20-20 targets) in PRIMES report "EU energy trends to 2030" (updated in 2009)
2 "Roadmap 2050" estimates for fuel shift 2050 back-casted to 2020 and 2030; EVs exponentially, Buildings and Industry (heat pumps) linearly. Fuel shift has been allocated to each country by share in EU car fleet (EVs) and share in EU industrial and residential fossil fuel demand (heat pumps)
3 "Roadmap 2050" estimates for energy efficiency 2050 linearly back-casted to 2020 and 2030

SOURCE: PRIMES, Roadmap 2050; Team analysis

Basic assumptions for generation technologies 2020 for new builds[1]

2020

Type of generation		Generation technologies	Capex €/KW	Opex fixed €/KW	Opex variable €/MWh	Fuel €/MWh	Construction time years	Lifetime years	Learning rate percent
Fossil		Coal Conventional	1,434	20	1	24	4	40	0
Fossil		Gas Conventional	717	15	1	52	3	30	0
Fossil		Coal CCS[2]	2,800	70	3	30	5	40	10
Fossil		Gas CCS[2]	1,434	29	2	62	4	30	10
Fossil		Oil	765	17	1	140	3	30	0
Nuclear		Nuclear	3,280	0	12	8	7	45	4
RES	Variable	Wind Onshore	1,053	21	0	0	2	25	5
RES	Variable	Wind Offshore	2,689	41	0	0	2	25	5
RES	Variable	Solar PV	1,765	17	0	0	1	25	15
RES	Non-variable	Solar CSP	3,800	114	0	0	3	30	10
RES	Non-variable	Biomass dedicated	1,970	14	9	34	2	30	0
RES	Non-variable	Geothermal	2,705	100	0	0	4	30	10
RES	Non-variable	Hydro	1,886	8	0	0	4	50	0
Back up		OCGT	350	0	1	90[3]	2	40	0

1 LCOE based on these assumptions
2 Storage included in variable Opex costs
3 Based on ICL/KEMA output

SOURCE: Stakeholder workshops; Road Map 2050 analysis

Basic assumptions for generation technologies 2030 for new builds[1]

2030

Type of generation		Generation technologies	Capex €/KW	Opex fixed €/KW	Opex variable €/MWh	Fuel €/MWh	Construction time years	Lifetime years	Learning rate percent
Fossil		Coal Conventional	1,371	20	1	24	4	40	0
Fossil		Gas Conventional	685	15	1	56	3	30	0
Fossil		Coal CCS[2]	2,199	56	10	30	5	40	10
Fossil		Gas CCS[2]	1,117	22	5	67	4	30	10
Fossil		Oil	731	17	1	156	3	30	0
Nuclear		Nuclear	3,237	0	12	8	7	45	4
RES	Variable	Wind Onshore	1,014	20	0	0	2	25	5
RES	Variable	Wind Offshore	2,440	25	0	0	2	25	5
RES	Variable	Solar PV	1,341	13	0	0	1	25	15
RES	Non-variable	Solar CSP	3,267	98	0	0	3	30	10
RES	Non-variable	Biomass dedicated	1,782	12	9	32	2	30	0
RES	Non-variable	Geothermal	2,275	80	0	0	4	30	10
RES	Non-variable	Hydro	1,819	8	0	0	4	50	0
Back up		OCGT	350	0	1	121[3]	2	40	0

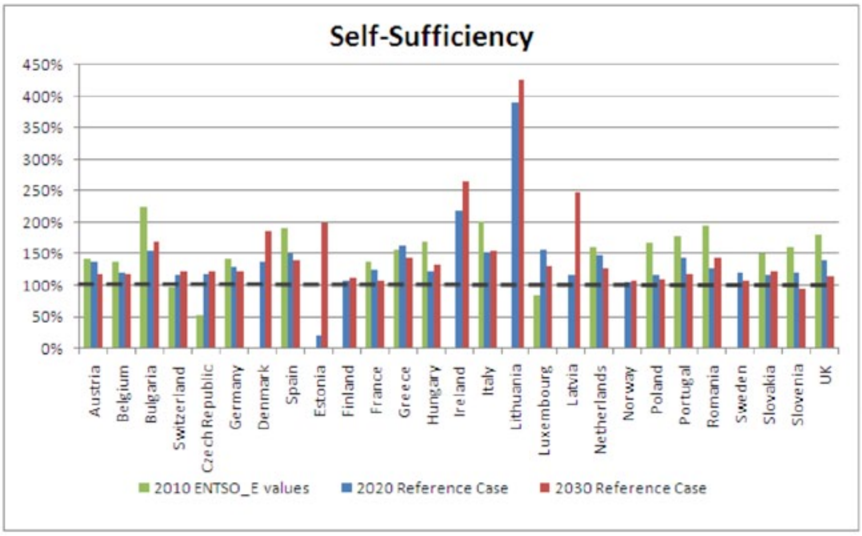
1 LCOE based on these assumptions
2 Storage included in variable Opex costs
3 Based on ICL/KEMA output

SOURCE: Stakeholder workshops; Road Map 2050 analysis

Import/export of each country is limited in 2020, as each country is expected to be more or less self-sufficient (with a few exceptions). In 2030 more import/export is allowed, constrained by a threshold on the reserve margin. Nevertheless, the figures in the exhibit illustrate that self-sufficiency is preserved despite the increase in RES capacity for almost all countries. In some cases it even increases slightly (as shown for Italy) or significantly (almost 30% in Denmark).

Self – sufficiency[1] is preserved despite the increase in RES capacity for almost all countries

IP In some case it even increases slightly (as shown for Italy) or significantly, like in the case of Denmark (by almost 30%) [2]



Similar results are observed even for the 2030 Higher RES scenario. Situation changes drastically when less transmission is introduced in the Higher RES scenario, where self-sufficiency drops below the 100% levels for most of the countries.

1 Self - sufficiency defined as maximal plausible energy production of all conventional thermal sources (coal, gas, OCGT) (at load factor of 90%) plus the modeled output of nuclear and renewable sources in the region divided by the annual electricity demand.
2 2010 values from ENTSO-E data available for certain countries only

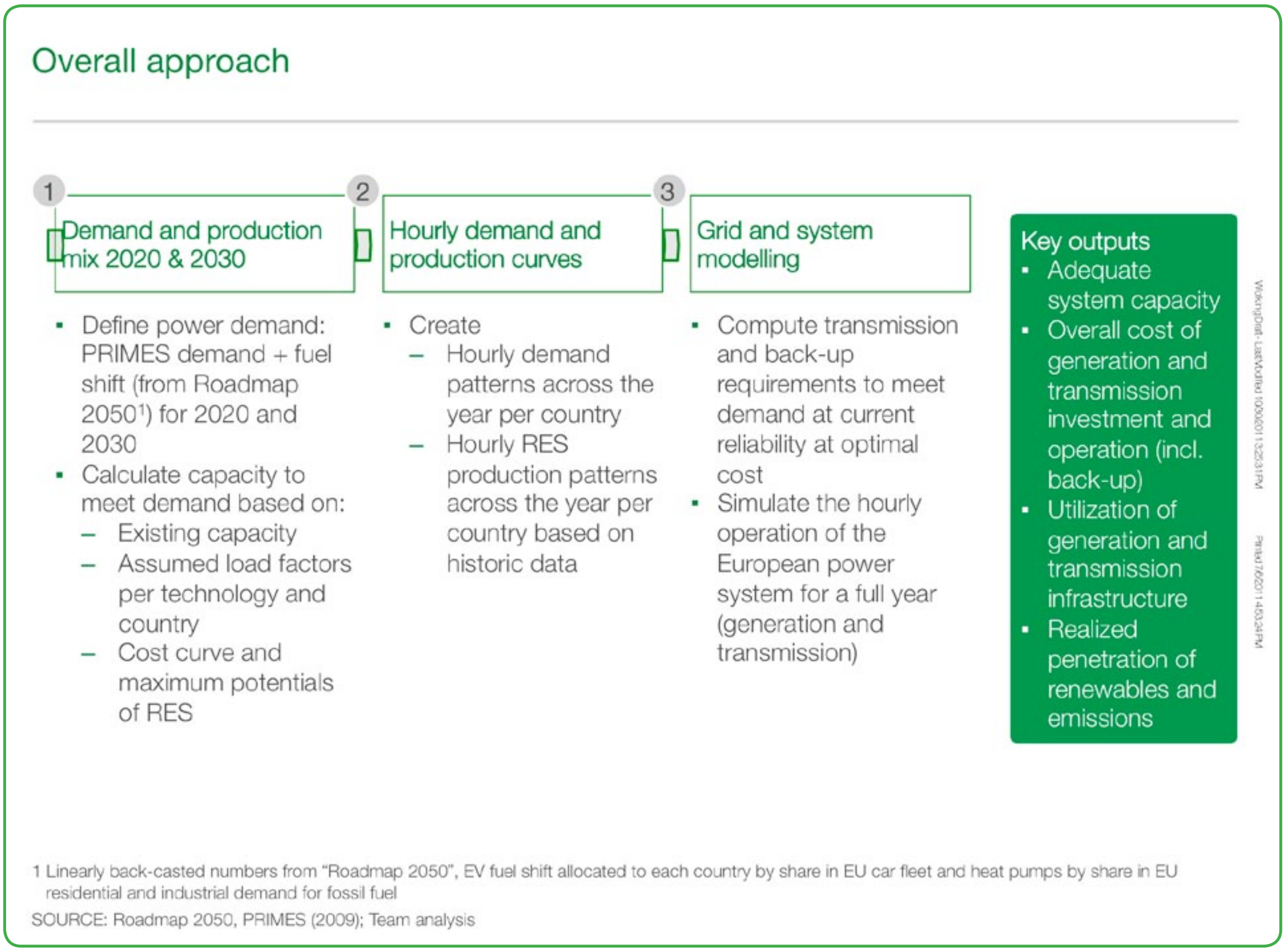
SOURCE: KEMA; Imperial College London; McKinsey

Production mix - Defining the production mix

Defining the production mix is a process containing several steps as already indicated in the methodology section in the beginning of the report:

2. Calculation additional RES needed

Up to 2020 both capacity and production are based on NREAPs. There are no adjustments for any potential reductions due to implementation challenges on these plans.



1. Calculation existing production from existing capacity

Existing RES capacity is taken directly from NREAPs of each country until 2020. From 2020 onwards retirements of existing capacity are being rebuilt (as in *Roadmap 2050*). RES capacities of 2010-2020 for Norway and Switzerland are taken from Global Insights.

Capacity in place and capacity under construction are taken from Powervision with the same economic lifetime assumptions as in Roadmap 2050, but manual adjustments are done for larger countries if expectations for reality are different. We have avoided any early retirements of existing assets if emission constraints allow this.

Beyond 2020 the EU-27 production mix is based on a cost-optimized pan-European distribution, taking into account existing deployment of RES by 2020 (except hydro power for which capacity is assumed to grow by IEA WEO 2010 and Other RES is assumed to stay constant).

3. Calculation supply gap

The supply gap consists of demand not yet covered by existing production and additional RES.

4. Fill remaining gap
The remaining supply gap is filled with a mix of nuclear, coal and gas that meets the supply gap, meets the emission ambitions and optimizes the costs of investments.

For 2020 and 2030, based on a bottom-up assessment of nuclear builds by country, taking average of high and low estimates. Includes input from World Nuclear Association and assessment by experts. Methodology for nuclear consists of 1) constructing high/low estimates from public sources and experts; 2) taking the average of those estimates; and 3) subtracting new nuclear already under construction, which comes online before/in 2020". So, the actual cost profile was not a factor in this.

For CCS the following assumptions are taken: by 2020 only demo (coal) plants are CCS-active; All coal & gas built from 2011-2030 is CCS-ready (based on EU Directive); Between 2020-2030, 50% of the coal built (2011 onwards) becomes CCS-active and 25% of the gas built (2021 onwards) becomes CCS-active[86]. In the *Less nuclear and CCS* scenario, other assumptions were applied as described above.

5. Allocate production mix to each country
Resulting production mix on EU-27+2 level is allocated to each country according to:

• Its share in the RES cost curve that is being built
• Nuclear potential that is being built
• Coal and gas potential that is being built

A.4. GRID MODELLING

The grid modelling uses a '48 nodes' representation of the European transmission network: 76 cross-border lines, which are supplemented with additional internal connections within some countries and completed by 12 connections from/to the peripheral countries.

The applied power system analysis model seeks to minimize the total system costs comprising:
- additional generating capacity (back-up);
- additional transmission network capacity; and
- annual electricity production cost.

These are all calculated while maintaining the required level of system reliability and respecting operating constraints. This cost minimization process considers tradeoffs between the costs of additional generating capacity (back-up plants), additional transmission infrastructure, renewable energy curtailment and transmission constraint costs incurred for network congestion management. The economic trade off is calculated by assessing the annuitised costs (approximated to be one tenth of the capital cost) of:

- New generation capacity (assumed to be equivalent to open cycle gas turbines at €350,000 per MW of capacity);
- Costs of new transmission lines, which are differentiated by technology (AC, DC, subsea) and terrain (simple, rough, mountain), ranging between € 0.7 million per km for AC lines in simple terrain to € 1.8 million per km for subsea cable; and
- Incremental operating costs.
- In the case of a loss of load, an additional cost of €50,000/MWh is assumed. Similarly, a lack of investment in transmission could lead to curtailment of generation output (with the associated cost of replacing that scheduled output with other output) or a loss of load.

The overall modelling framework simultaneously optimises investments and hourly system operation across the time horizon of a year.

86 These assumptions are in line with recent sources, such as ZEP (http://www.zeroemissionsplatform.eu/, see CCS reports), in expecting demo plants only up to 2020 and the need to drive down cost to make CCS commercially available from 2020 onwards

The infrastructure (generation and transmission) evaluation model captures the effects of sharing generation capacity through transmission in order to minimize the overall additional infrastructure costs needed to deliver the required level of reliability. In terms of loss of load expectation (LOLE) this is less than 4 hours per year under alternative portfolios of generation. The integrated reliability assessment calculates the LOLE by assessing whether adequate generation will be available for each hour of the year to meet the corresponding demand. This is based on an array of probabilistic inputs, which the model takes into account. These include the effects of forced outages of generating plant, an optimised production schedule from the available conventional generation technologies, the seasonal availability of hydro power (as well as the variability of 'run of river' and hydro with reservoir), dispatch of Concentrated Solar Power production, considering thermal reservoir capacities thermal storage losses, and the probable contribution from renewable generation and the associated short and long-term correlations with demand.

Key inputs to the investment model include a time series of hourly electricity demand profiles and regional hourly profiles for the available renewable energy sources (wind and solar), seasonal hydro energy for both 'run of river' and hydro with reservoir, installed capacity, dynamic characteristics and operating costs of generation, investment cost of additional generating capacity in each region, network topology and network reinforcement cost. Key outputs of the model are the additional generating capacity and secured transmission capacity.

In order to deal with the uncertainties associated with conventional generation availability, demand fluctuations and variability of output of (variable) renewable generation two types of operating reserve are modelled:

- Short-term reserve (from seconds to few minutes time periods) for automatic frequency regulation requirements; and
- Long-term reserve (from few minutes to few hours time periods) to mitigate unforeseen imbalances between demand and supply over longer time horizons in each region.

The determination of the amount of reserve requirements is based on the volumes currently procured in each country, subject to additional reserve requirements in order to deal with the variable output from wind and solar. A conservative approach has been followed by not including the contribution of any frequency sensitive loads towards frequency regulation (for example smart refrigerators).

The stochastic modelling of variable renewable generation results in an optimal allocation of long-term operating reserve between standing reserve and synchronised spinning reserve plant to maintain supply/demand balance. Any inadequacy in terms of the ability of the system to meet the demand, given the need for reserve, is managed by appropriate augmentation of generation capacity.

The dynamic scheduling process is modelled looking ahead over a 36 hour period at the demand profile to be met and associated reserve requirements. The model then schedules generation, storage and demand response for each 24-hour time horizon to meet these requirements. The actual day-ahead is varied by the stochastic modelling of the energy output from the renewable generation sources. The stochastic framework allows a number of renewable output realizations to be evaluated for each hour looking forward 36 hours. The generation and responsive demand resources in each region are simultaneously scheduled in order to consider multiple renewable generation output conditions for a prescribed set of network constraints. The model takes account of losses and costs incurred through the use of demand response and storage resources.

The key outputs of the stochastic scheduling and reserve model include hourly dispatch of each generation technology; hourly utilization of storage and demand response in each region; hourly allocation of operating reserves, renewable curtailment assessment and associated costs; transmission flows and congestions (flow duration curves); disaggregated total system operational costs per year including; start-up, no-load, fuel, losses and cost of renewable energy curtailment.

A.5. GAS INFRASTRUCTURE MODELLING

A key issue in the decarbonisation challenge, characterised by increasing shares of variable renewable sources, is the importance of supplying flexibility and/or back-up and the role of gas.

The simulation of the European power system principally assumes that there are no limits to the availability of gas supply, in terms of the annual volumes as well as daily or even hourly gas flexibility. This assumption may not hold, however, in all cases, in particular in case of drastic increase of gas-fired power generation, including back-up capacity.

To test this assumption, a simplified model of the European gas infrastructure in the year 2030 has been used. Similar to the grid model used for the electricity sector, the gas model is based on a simplified representation of the European gas network, which represents existing infrastructures plus FID proposed projects as stated in the 10-year network development plan of ENTSO-G. As far as possible, the grid topology of the gas model follows the same structure as for electricity, although it excludes areas without gas supply (such as Northern Norway and Sweden).

Apart from the transport infrastructure, the gas model also covers demand, local production, storage, LNG and line pack, in order to enable a proper analysis of available flexibility at a daily or even hourly level. The corresponding assumptions are based on publicly available forecasts (such as PRIMES, ENTSO-G etc.) and are consistent with those used for the power system analysis, for instance with regards to energy efficiency or the fuel shift from gas to electricity. All assumptions on gas-fired electricity generation have been taken from the power system analysis.

In contrast to the grid modelling of the European power system, the gas infrastructure modelling has been limited to simulating the daily operation of the European gas network, whilst the underlying grid infrastructure has been kept constant. The objective of the gas model thus is to minimise the total costs for matching gas demand, whilst taking into account capacity and dynamic constraints of gas production, transmission networks, storage and LNG. Apart from a daily timescale, we have also analysed possible limitations to the provision of flexibility within a day (i.e. at a timescale of one hour).

A.6. COST CALCULATIONS

Capex

Cost reduction can be based on either annual reduction or learning rate. Other key assumptions taken are:

- Capex reduction for CCS due to learning rate is assumed to be depending on both coal and gas-with-CCS (same as *Roadmap 2050*)
- Deployment of Wind and Solar PV also includes deployment in the rest of the world for 2010-30. Rest of World deployment is not corrected for replacement of retirements.
- Capex of fossil plants that are already under construction is not included

Levelised cost of electricity (LCOE)

The levelised cost of electricity (LCOE) calculations only include new builds and do not include the cost of existing installed capacity (same approach as *Roadmap 2050*), so the LCOE gives the average cost per MWh (per technology) of all the new builds in a particular year. Comparison with revenue gives insight into the attractiveness of investments in this new capacity.

LCOE is first calculated per technology (including back-up) using 7% WACC, 25% tax rate, 1.3 exchange rate EUR/USD and no inflation. The total cost is based on the present value of capex and opex (including fuel costs (corrected for energy efficiency), fixed and variable maintenance costs, CCS infrastructure costs and carbon costs of new builds. The total production per year is determined based on the grid model outputs. For detailed assumptions on input assumptions see additional methodology slides avaible on the website: www.roadmap2050/PP2030

The additional transmission capex is allocated to the total production of variable renewable energy sources. This results in additional cost of ~€6/MWh per variable technology.

The overall LCOE is then calculated by weighting the LCOE per technology by the production of the new builds in a particular year. Carbon price is not included in deriving the generation mix per scenario, however it is used in calculating the cost of electricity.

The power system consists of generation and grid and will be assessed on levelized cost of electricity

Generation cost (numbers based on McKinsey model)

Cost to produce electricity by new builds compared by calculating levelized cost of electricity taking into account

- Capex
- Opex
- Fuel cost
- Lifetime
- Load factor[1]
- CCS infrastructure cost
- Carbon costs

+

Grid cost analysis (numbers based on KEMA/ICL model)

Cost to balance demand/supply at any point in time, taken into account

- Transmission grid investments, added to Capex of renewable sources weighted by additional capacity per technology
- Cost to produce electricity using OCGT back-up plants (including capex[2], opex, fuel costs, CO2, lifetime and load factor)

Full cost of electricity for new builds based on the complete additional system cost including generation and grid

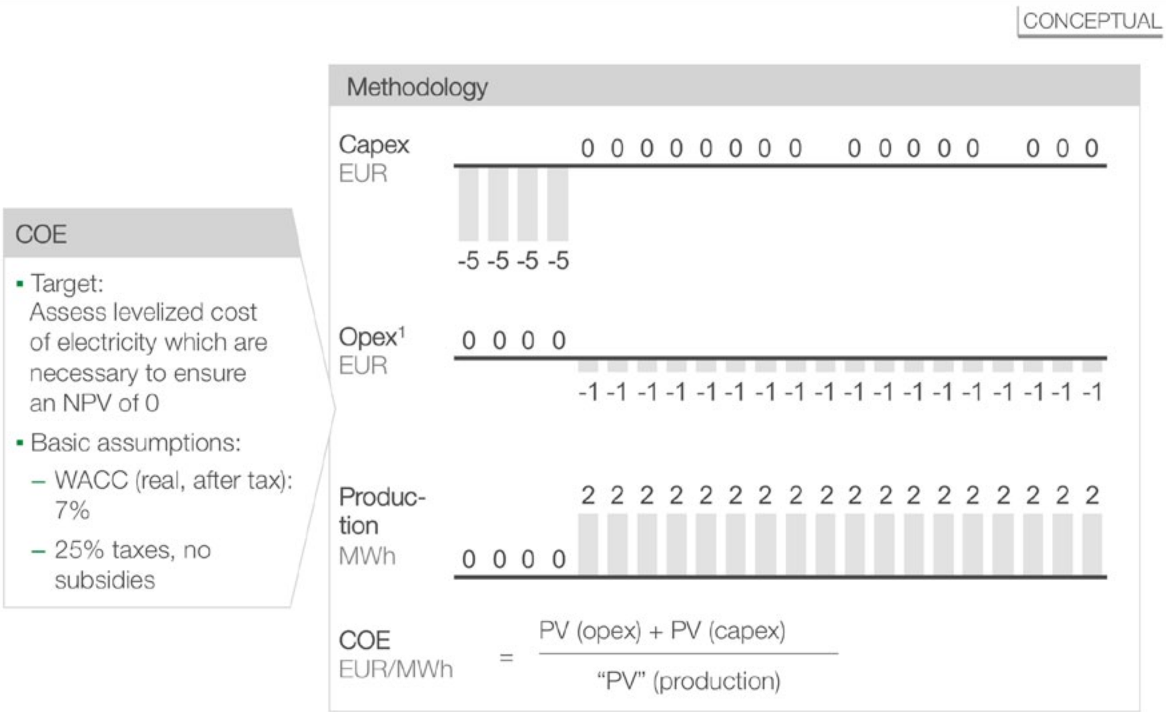
1 Loadfactors for overall LCOE based on McKinsey model assumptions for new builds as per roadmap 2050, LCOE per technology based on ICL/KEMA outputs reflecting an weighted average of new and existing builds based on capacity mix
2 All additional capacity from the ICL model is assumed to be new build
SOURCE: Team analysis

General assumptions

Required assumptions	Assumptions
▪ WACC	7%[1]
▪ Tax rate	25%
▪ Exchange rate EUR/USD	1.3[2]
▪ EUR real vs. nominal	Real

1 Real, after tax; ~9% nominal; ~12% nominal before tax
2 Macro model assumes: 2000-2010: 1.21, 2011-2020: 1.29, 2021-2030: 1.31, 2031-2040: 1.36
SOURCE: Team analysis

The levelised cost of electricity (LCOE) is based on the present value of Capex, Opex and production



1 Including fuel, CO2, operations and maintenance and CCS infrastructure costs
SOURCE: Team analysis

A.7. LIST OF DEFINITIONS

Low-carbon technologies – This group of technologies entails all RES technologies, CCS on coal or gas and nuclear.

CCS – Large combustion plants with carbon capture and storage.

RES – Renewable Energy Sources; it represents a family of technologies of which some are variable (solar PV, wind on-shore and wind off-shore) and some non-variable (hydropower, biomass plants and geothermal). Other RES technologies have only a marginal role in the report despite promising outlook (tidal, wave, solar CSP, etc)

Back-up – In this report, the term 'back up' refers to all generation capacity that is required in addition to RES and flexible baseload plants, in order to ensure the desired level of supply reliability. In most cases, back-up plants are required to provide sufficient contingency reserves, i.e. at times when variable RES is unable to supply sufficient electricity. It should be noted that back-up capacity does not necessarily have to be provided by flexible plants, although a certain share of back-up capacity also have to be able to support the provision of operating reserves.

Contingency reserves – Contingency reserves are required to compensate an expected shortage of generation capacity that may occur from time to time, for instance due to prolonged plant or transmission outages, or due to the limited availability of electricity from variable RES (e.g. at times of low wind during the winter season with low solar radiation). In contrast to operating reserves, contingency reserves can be provided by all generation technologies that can supply electricity at any time, without any particular requirements on flexibility.

Baseload – Traditionally, the term baseload capacity refers to plants that are running at high to very high load factors (≥65% of the time). Baseload plants are often characterised by a limited operational flexibility, i.e. with a limited ability to quickly adjust their output.

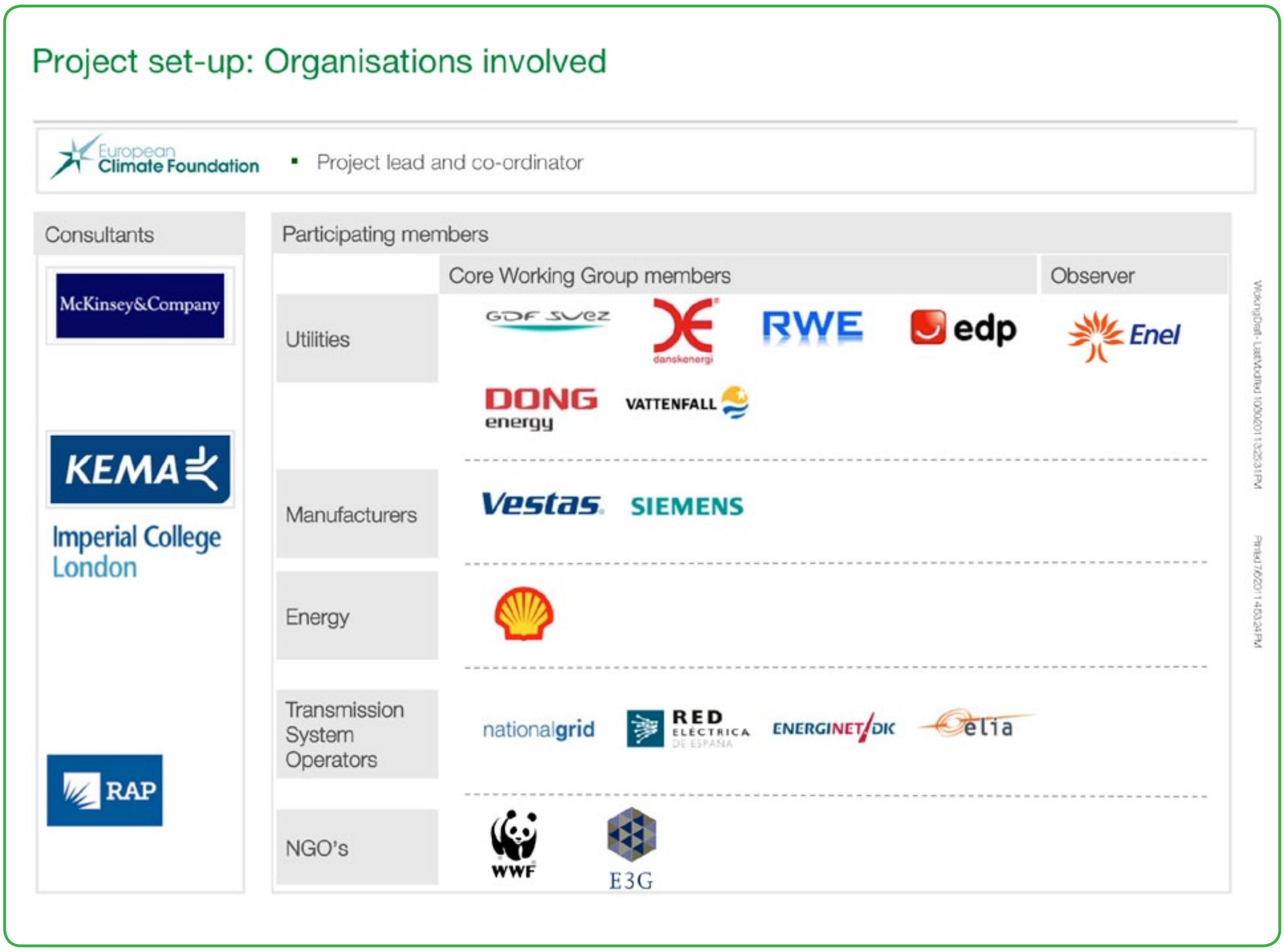
Flexible baseload – In a power system with a large share of electricity from RES, including a considerable contribution from variable sources such as wind or solar power, the residual load to be provided by other plants will often be characterised by significant volatility. In contrast to traditional baseload capacity, the corresponding plants will therefore have to operate in a pattern that is more similar to traditional mid-merit plants and which requires significant operational flexibility, in order to adjust to the variable demand in real time.

Operating Reserves – Operating reserves cover the whole range of ancillary services that are required by system operators to maintain and/or restore the energy balance of the power system during a given day. In the modelling framework used for this study, operating reserves therefore combine reserves and response.

Reserve – In this report, the term ‘reserve’ (when used in isolation) refers to that part of operating reserves, which can be activated within a timeframe of approx. 4 hours and which will be used when other capacity cannot provide the output as scheduled, e.g. due to plant failure or because the primary energy, e.g. wind, is not available. This service can only be provided by plants that either are in operation (i.e. synchronised with the system) or are flexible enough to start within a corresponding timeframe.

Response – Response provides an instantaneous reaction to a change in load or generation (e.g. due to a failure) and manages second by second variations. It can thus only be provided by plants that are in operation (i.e. synchronised with the system) and that are flexible enough to adjust output within a time period of some seconds to several minutes.

B. ORGANISATIONS INVOLVED



POWER PERSPECTIVES 2030

Power Perspectives 2030 is a contributing study to Roadmap 2050: a practical guide to a prosperous, low-carbon Europe. The objective of this report is to identify what is required to get on track in the next two decades to full decarbonisation of the power sector by 2050, while ensuring energy security and competitiveness.

The analysis was conducted by a consortium of experts including KEMA; The Energy Future Lab at Imperial College London; the Regulatory Assistance Project (RAP), and E3G. The European Climate Foundation acted as a neutral convener and project manager of the report.

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A wide range of companies, transmission system operators, technology manufacturers, consultancy firms, research centres and NGOs have provided various forms of assistance during the preparation of the report, which started in February this year. These organisations have provided valuable counsel that has been faithfully reflected in this analysis. Their willingness to consult and to be consulted in the course of this work should not be understood as agreement with all of its assumptions or conclusions.

The ECF wishes to thank the members of the core reflection group for participating to the bi-monthly meetings and for having provided feedback throughout the development of Power Perspectives 2030. These are: utilities, technology manufactures and energy companies, EdP, Dansk Energi, Dong Energy, GdF Suez, Siemens, Shell, Vattenfall, Vestas and RWE; the transmission system operators, Energinet.dk, Elia, NationalGrid, Red Electrica Espagnola and Tennet; and NGOs, E3G (Third Generation Environmentalism), WWF (European Policy Office). Enel has participated to the project as observer.

For more information on Power Perspectives 2030:
Www.roadmap2050.eu/pp2030

CONTRIBUTING STUDIES TO ROADMAP 2050

The Contributing Studies to Roadmap 2050 is a set of publications strategically addressing some of the main challenges and short-term priorities as identified by the Roadmap 2050 analysis in the move towards a low-carbon economy in Europe.

ROADMAP 2050

The mission of Roadmap 2050 is to provide a practical, independent and objective analysis of pathways to achieve a low-carbon economy in Europe, in line with the energy security, environmental and economic goals of the European Union.

The Roadmap 2050 project is an initiative of the European Climate Foundation (ECF), and has been developed by a consortium of experts funded by the ECF. The core of the Roadmap 2050 analysis is contained in the following 3 volumes:

- Volume I: Technical and Economic Analysis
- Volume II: Policy Report
- Volume III: Graphic Narrative

For more information on Roadmap 2050:
www.roadmap2050.eu

European Climate Foundation:
www.europeanclimate.org

Power Perspectives 2030
On the road to a decarbonised power sector

www.roadmap2050.eu/pp2030