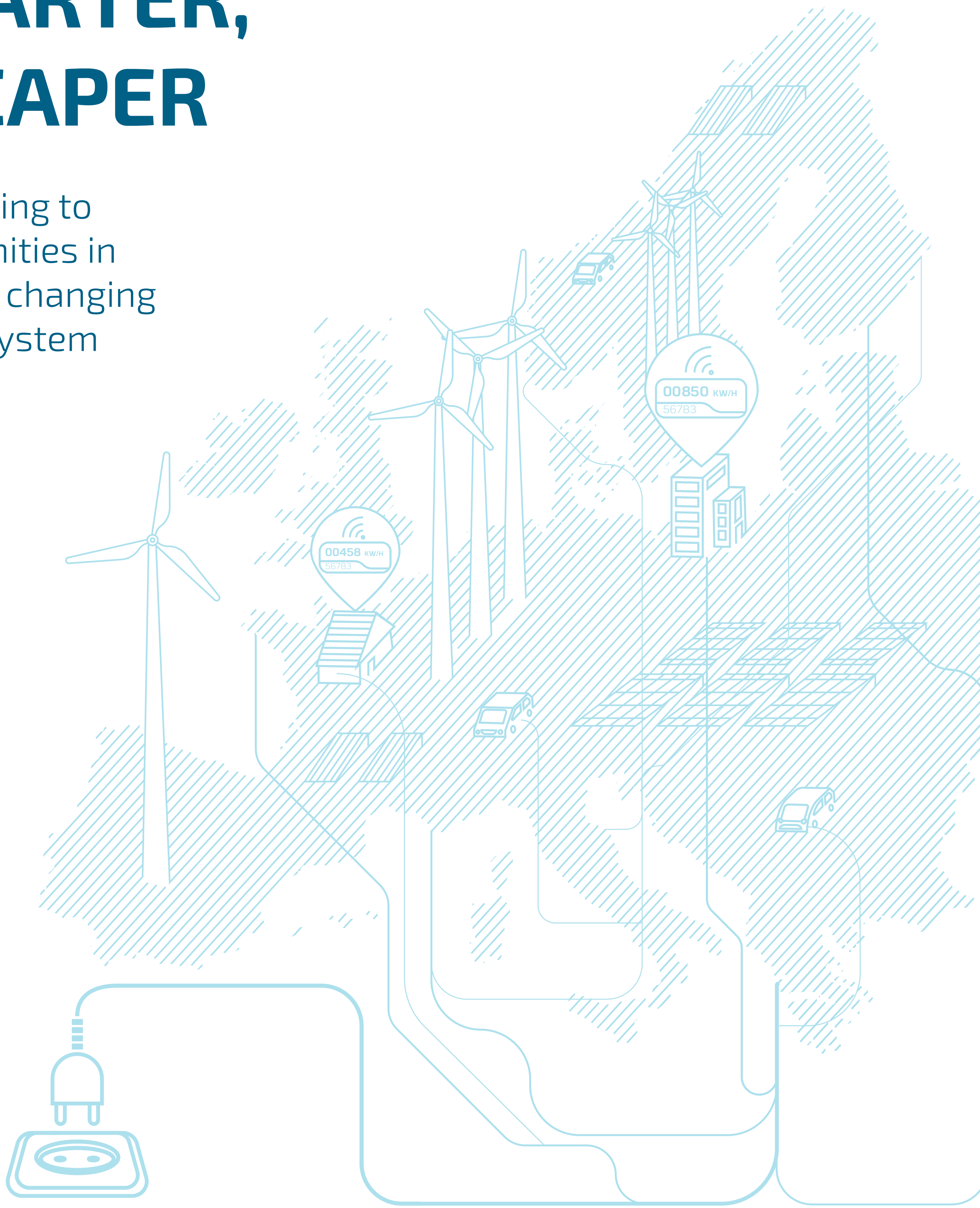
Energy Union
Choices

CLEANER, SMARTER, CHEAPER

Responding to opportunities in Europe's changing energy system



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Preface

Dear Reader,

These are exciting times for the energy transition. The drop in the cost of clean technology has gone far beyond all expectations, tipping the economics in favour of decarbonisation. Meanwhile, global action on climate change further accelerates clean energy innovation and deployment, creating ever stronger momentum.

This is game-changing. How should Europe respond to this new reality?

To answer that question, the European Climate Foundation and partners in the Energy Union Choices consortium asked experts from Artelys to update the outlook for the European power sector up to 2030. We compared policy-makers' existing ambition levels to what could be achieved in light of these fundamental changes in the energy system.

The report finds that Europe can aim for much deeper emission reductions and higher renewables uptake by 2030 at similar or even reduced cost.

While this is great news, the responsibility now lies with European politicians to deliver the right policies. With this report, we invite decision-makers to embrace the new opportunities in the energy sector and to decisively opt for higher ambition as the only viable pathway for Europe.

I hope you enjoy reading!

Kind regards,

Laurence Tubiana,
CEO of the European Climate Foundation

Key findings at a glance:

1. Faster decarbonisation of the power sector is technically feasible and can be economically more attractive than current 2030 ambition levels. Power sector emissions can reduce almost twice as fast (from -30% to -55% in 2030 from 2015), while saving on system costs (-600mln EUR) and bringing net job benefits to Europe (+90,000)

2. The power system can integrate substantially higher shares of renewable electricity than currently projected for 2030, and at lower cost. By 2030, at least 61% of Europe's electricity can come from renewable sources. This is well above the 49% renewable electricity share projected under current ambitions (reflecting the overall 27% RES target for 2030).

3. A smart and swift transition out of coal is indispensable in order to tap into the opportunities presented by cheaper renewables. Current EU policies do not tackle the issue of overcapacity which is holding back investments in renewables and flexible demand solutions. Flexible demand policies are essential to smartly integrate electric vehicles and heat pumps as major new sources of clean flexibility, replacing thermal generation.

4. Gas generation declines considerably compared to today, even with large shares of coal retiring. Gas generation is cut in half by 2030 (from 514 TWh today to 259 TWh), even in combination with coal retirement. As grids and flexible demand provide for more system balancing at lower cost, the bridging role of gas in the power sector transition decreases.

5. Interdependency between national electricity systems should deepen, with benefits shared by all. A narrow, national perspective on power system security fails to reap the significant cost savings offered by cross-border cooperation (EUR 3.4bn per year in 2030). The proposals in the Clean Energy Package are key to making optimal use of existing electricity network infrastructure and meeting energy security objectives at lower cost.

Glossary

Abbrev.	Explanation
BEV	Battery electric vehicle
CAES	Compressed air energy storage
CAPEX	Capital expenditures
CCGT	Combined-cycle gas turbine
CEP	Clean Energy Package
COM	European Commission
CPS	Current plans scenario
DSO	Distribution system operator
DSR	Demand side response (includes load shedding and load shifting)
DSR-only	Sensitivity calculation focussing exclusively on smart electrification
EE	Energy efficiency
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EU ETS	EU emissions trading system
EU28+2	European Union plus Norway and Switzerland
EUCO30	COM scenario that meets all 2030 targets and a 30% energy efficiency target
EV	Electric vehicle
FOC	Fix operation costs
GHG	Greenhouse gases
GW	Gigawatt (capacity unit)
HP	Heat pump
IPS	Incomplete plans scenario
LCOE	Levelised costs of electricity
NOx	Nitrogen oxides
NRA	National regulatory authority
NTC	Net transfer capacity
OCGT	Open-cycle gas turbine
OPEX	Operational expenditures
OPS	Opportunity scenario
PCI	Projects of common interest
PHEV	Plug-in hybrid electric vehicle
PHS	Pumped hydroelectric storage
PRIMES	Energy system model from the University of Athens, used for the preparation of the COM scenarios
PV	Photovoltaics
RES	Renewable energy source
RES-E	Electricity from renewable energy sources
RETIRE-only	Sensitivity calculation focussing exclusively on smart retirement
RTP	Real-time pricing
Smart electrification	Policy strategy that aims to capture the flexibility value of new, electrified and distributed loads coming from electric vehicles, heat pumps or industrial and commercial processes
Smart retirement	Transition strategy that aims to reduce coal capacity in a socially correct and just manner
SO	System operator
SOx	Sulphur oxides
TSO	Transmission system operator
TWh	Terawatt hour (energy unit)
TYNDP	Ten-Year Network Development Plan (bi-annually prepared by ENTSO-E and ENTSOG)
V2G	Vehicle-to-grid (electricity infeed from EVs into the grid)
vRES	Variable renewable energy source (i.e. wind power and solar PV)
WACC	Weighted average cost of capital

Executive Summary

The cost of clean energy technologies is declining dramatically[1]. While impressive reductions have already taken shape, all signs point in the direction of further improvements, in many cases merging with digital solutions, driving electrification, innovation and competition in energy business models.

Few actors in the energy field, politicians or business leaders, had considered these developments as realistic. Many now acknowledge they would have taken different, bolder and more ambitious decisions if they knew then, what we know now.

In light of these reflections, the *Energy Union Choices* consortium[2] embarked on an exercise to assess the opportunities from this emerging energy landscape. The report uses the latest projections on technology cost and performance by 2030 as an acknowledgement of the new realities, based on real world cost reductions as well as an intense consultation with leading experts and industry groups[3].

By contrast, the reference scenarios for the current EU energy debate, in particular the European Commission's Impact Assessments for the *Clean Energy for All Europeans Package*, use modelling that relies on outdated technology cost projections for 2030 and 2050 that are significantly higher than real-world costs seen in the market in 2016 and 2017. While the Commission recognises the shortcomings of its outdated approach, its modelling is still used as a benchmark in public debates. This will have repercussions on policy decisions if not challenged and debated in a public setting.

This report finds that the new energy reality fundamentally changes the outlook for the power sector in Europe. Europe can aim for deeper emission reductions and higher renewables uptake at similar or even reduced cost, if it makes the right policy choices and sets the right ambition levels.

This core finding applies even though the report makes careful and conservative assumptions in several technical and policy areas, for example around the cost of batteries, the potential for deeper efficiency, faster grid build-out or further reforms to the EU Emissions Trading System (ETS)[4]. It is

[1] Cost of LED lighting fell by 84% over 2010-2015, EV batteries and solar PV by 55% and 50% respectively over the same period. Bloomberg New Energy Finance expects solar PV costs to drop a further 66% by 2040, onshore wind by 47%, offshore wind 71%; cost of lithium-ion batteries down by 73% by 2030.

[2] The Energy Union Choices consortium brings together a group of non-for-profit think-tanks and civil society organisations: the European Climate Foundation (ECF), E3G, Agora Energiewende, the Regulatory Assistance Project (RAP), WWF and the Buildings Performance Institute Europe (BPIE).

[3] See acknowledgements, p16.

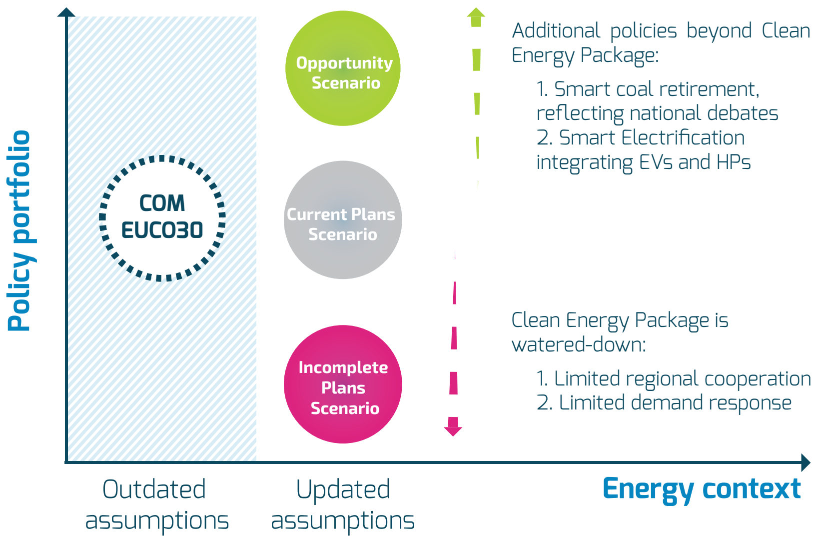
therefore possible, even likely, that the report still underestimates the full potential for cost-effective decarbonisation in the energy sector and provides a rather conservative 'baseline' picture.

Approach

The report compares three scenarios, each reflecting a different policy framework to 2030.

- The central *Current Plans Scenario* reflects the current EU energy acquis including the Clean Energy Package (CEP) as proposed by the European Commission;
- The *Incomplete Plans Scenario* represents an incomplete adoption of the Clean Energy Package with provisions on regional cooperation and demand response significantly watered down. At the time of publication, this scenario most closely corresponds to the state of affairs in the co-decision process;
- The *Opportunity Scenario* assumes a more complete policy portfolio, including the main elements of the *Current Plans Scenario* but going beyond it in two ways:
    1. Smart retirement: Member States advance national plans to retire coal plants, reflecting existing plans or the potential outcome of ongoing debates in the UK, France, Italy, Germany, Poland and Spain (amounting to a total reduction of 37 GW, compared to EUCO30). In France, this also means a reduction of 20 GW of nuclear capacity by 2030. In comparison with 2015, coal and nuclear capacities drop from 289 GW in 2015 to 153 GW under the Opportunity Scenario (-47%).
    2. Smart electrification: Member States implement robust policies to activate demand flexibility across the energy system with a specific focus on the smart integration of new and existing distributed loads coming from solar PV, electric vehicles (EVs), industrial processes (boilers) and heat pumps (HPs).

Figure 1: Scenario approach



[4] This report applies a carbon price of EUR 27/tCO2 in all scenarios, similar to the European Commission 2016 Impact Assessment for 2030. This is consistent with the (upper end of) forecasts from authoritative carbon market analysis, taking into account the ETS reform agenda as recently agreed between Council, Parliament and Commission. IETA GHG Market Sentiment Survey predicts an average price of EUR16/tCO2 in phase 4 (2021-2030); Poll from Carbon Pulse in July 2017 with the main carbon market analysts shows a median expected carbon price of EUR 25.50/tCO2 in 2030, http://carbon-pulse.com/37341/

Key findings

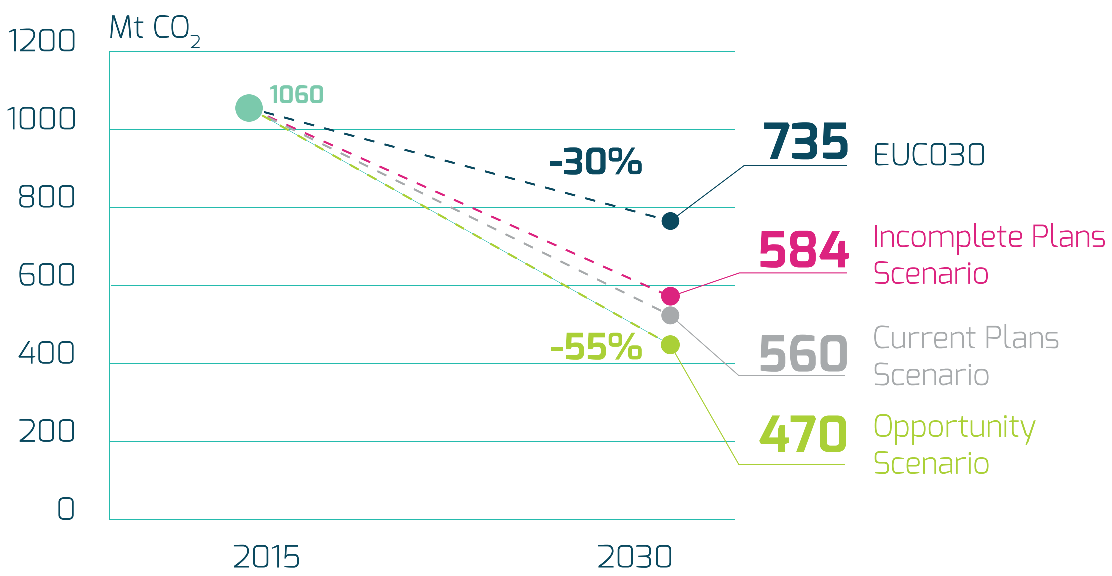
The key findings can be summarised in the following five points.

Finding 1: Faster decarbonisation of the power sector is technically feasible and can be economically more attractive than current ambition levels.

Recent changes in clean technology solutions open new opportunities for a faster transition towards a zero-carbon power sector.

The analysis shows carbon emissions from the power sector can drop by more than half in 2030 compared to today. This represents an additional reduction of 36% compared to EUCO30, the central scenario from the Commission's 2016 Impact Assessment. The *Current Plans Scenario* too comes with deeper carbon emission reductions than EUCO30, driven in particular by a more accurate depiction of renewable technology costs.

Figure 2: Power sector CO2 emissions for 2030 across the different scenarios



The scenario with the deepest emission reductions is also the scenario that can boast the best economic results, in terms of overall system costs (600mln EUR savings in 2030) and job creation potential (a net increase of 90,000 jobs in Europe).

Figure 3: Employment benefits in the *Opportunity Scenario*, compared to the EUCO30

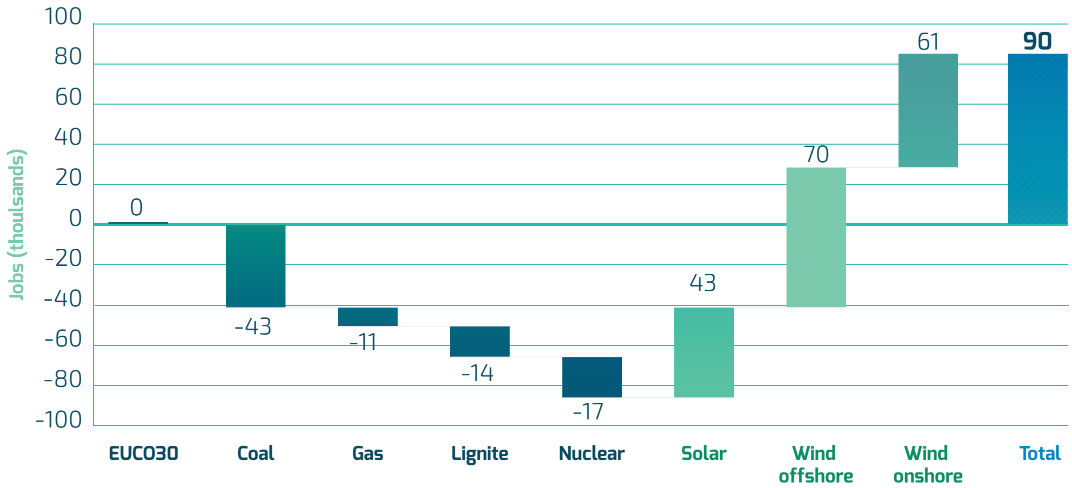
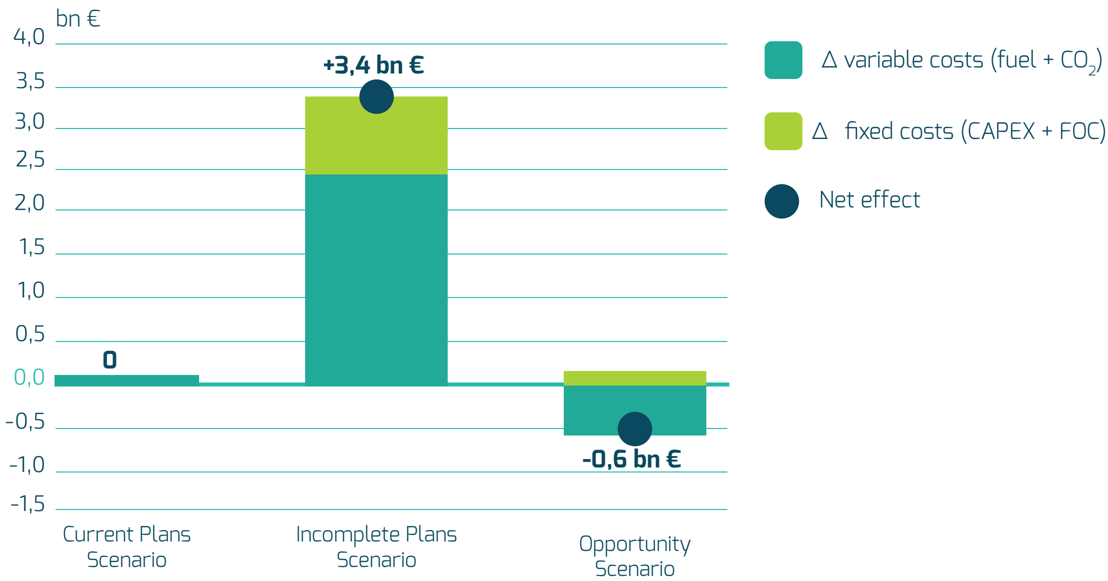


Figure 4: Overall system cost in the *Opportunity Scenario*, compared to the *Incomplete Plans* and *Current Plans* scenarios



These findings should increase confidence in the feasibility of deeper emission reductions in the power sector. That is welcome, considering that the European Union will soon need to set itself more ambitious goals to 2050 in light of the well below 2 degrees and net zero emissions objectives it signed up to in the 2015 Paris Agreement. The policy portfolio represented in the *Opportunity Scenario*, therefore, becomes particularly important to pursue.

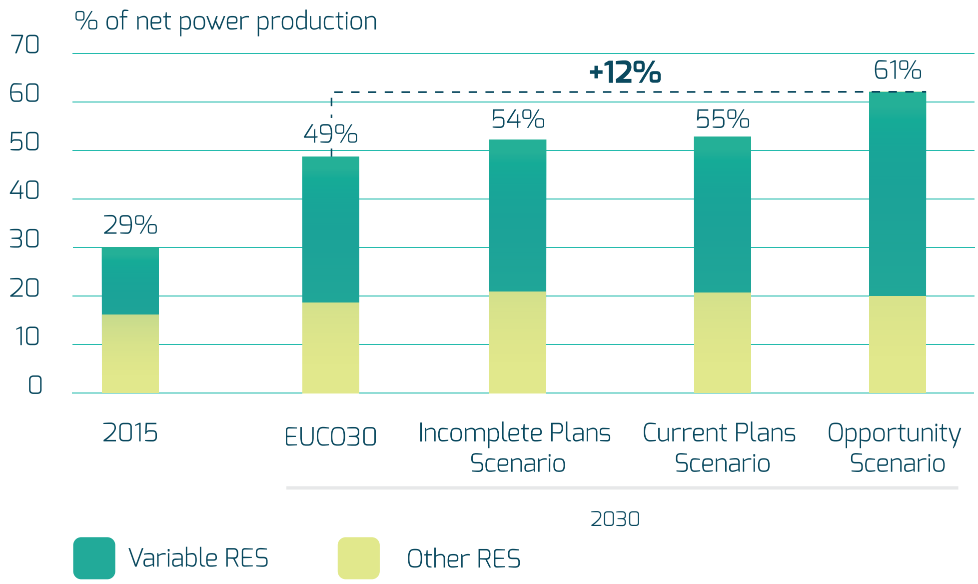
Finding 2: The power system can integrate substantially higher shares of renewables electricity in 2030 than currently projected, and at lower cost

The *Opportunity Scenario* shows renewable electricity can grow to at least 61% of net production across Europe. This is well above the 49% in EUCO30 (which reflects an overall 27% renewable energy target), and is also higher than any of the 2018 ENTSO-E and ENTSOG scenarios that underpin current energy infrastructure planning in Europe.

As shown in the below graph, the renewable share in the *Current Plans Scenario* is only a fraction higher than in the *Incomplete Plans Scenario*. It leads to the conclusion that, as such, the Clean Energy Package has little effect on the uptake of renewables, despite reduced costs.

It begs the question: what is holding back new investments in renewables? The *Opportunity Scenario* reveals the answer lies in tackling overcapacity in the European power markets (smart retirement) and scaling up demand side flexibility (smart electrification). In other words, additional policy measures are needed to induce a further step-change regarding renewable energy deployment while also reducing overall system costs.

Figure 5: Renewable electricity uptake, across the different scenarios

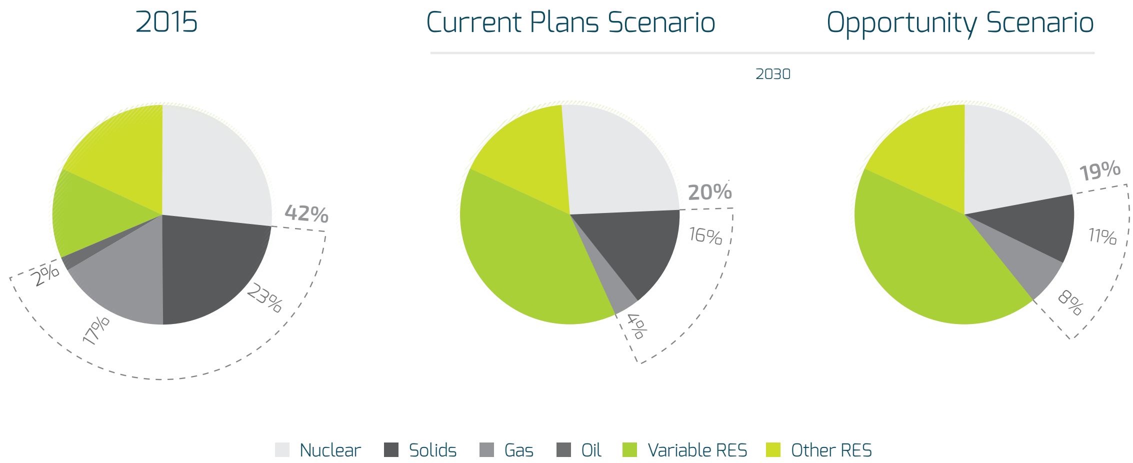


Finding 3: A smart and swift retirement of coal capacity is indispensable in order to tap into the opportunities presented by cheaper renewables.

While the report paints an attractive picture of the opportunities to accelerate the power sector transition, it is clear that none of this will happen without decisive political action. The policy portfolio described in the *Opportunity Scenario* not only requires full implementation of the Clean Energy Package as proposed by the European Commission, it also relies on Member States unambiguously advancing coal retirement strategies.

As is shown below, the report finds that, while coal generation decreases in the *Current Plans Scenario*, it continues to supply a large share of EU electricity in 2030. In the *Opportunity Scenario* coal generation falls further but only due to policy-driven retirement of coal plants, and not due to either the Clean Energy Package or the EU carbon markets in 2030. As coal overcapacity is holding back investments in clean alternatives, national coal retirement strategies seem essential to any clean energy strategy.

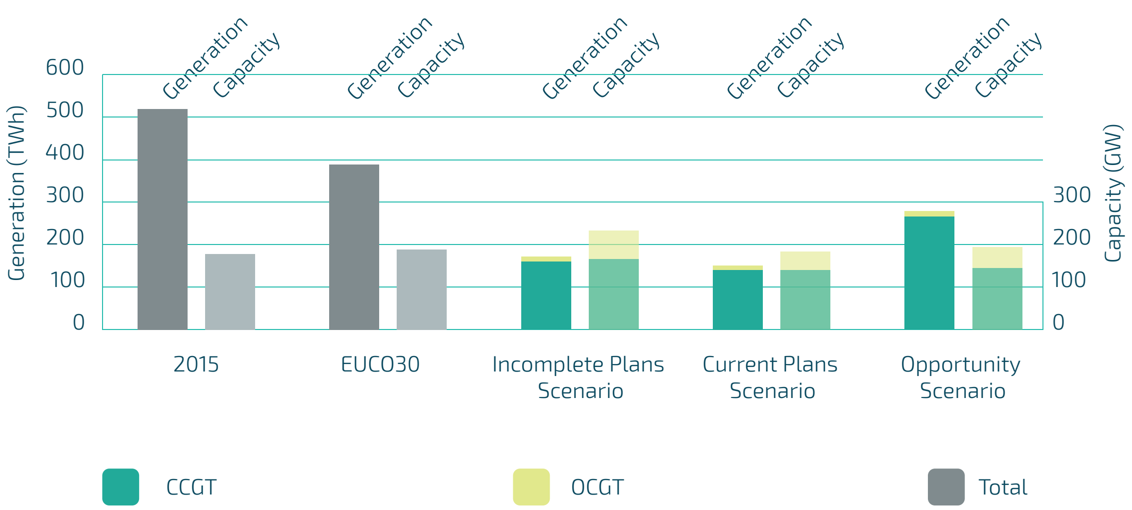
Figure 6: Electricity generation mixes in *Current Plans* and *Opportunity Scenarios*, compared to today



Finding 4: Gas generation declines considerably compared to today, even with large shares of coal retiring.

The variable nature of solar and wind technologies requires a more flexible system. Remarkably, however, gas generation, which is among the most important of conventional flexibility options currently used, considerably decreases in all of the scenarios, compared to today.

Figure 7: Gas capacities and net gas-based power generation across the scenarios, compared to today and EUCO30



The decrease is very pronounced in the *Current Plans Scenario*. This is due to a combination of low cost renewables and existing coal outcompeting gas generation in the merit order. Provided there are no dramatic changes to the carbon price, the analysis shows that existing coal continues to win in the market vis-à-vis gas and renewables. This situation is far from optimal in light of the EU's objectives to reduce emissions cost-effectively and work towards a more flexible power system.

In the *Opportunity Scenario*, where coal capacity is reduced, gas generation picks up again, but at substantially lower levels than in 2015 or levels projected in EUCO30 for 2030. As coal capacity falls sharply, the existing fleet of Combined-cycle Gas Turbines (CCGTs) runs more frequently. This should improve their profitably compared to scenarios without coal retirement, and is likely to improve further in case more coal capacity retires than analysed in this report.

New build gas generation, however, is found to be less competitive than new wind or solar power and other flexibility solutions. New gas plants are, therefore, not built, with the exception of a number of Open-cycle Gas Turbines (OCGTs) (i.e. gas peakers) at low running hours (±200h per year).

The report provides compelling evidence that the accelerated retiring of coal capacity does not necessarily require investments in new gas plants. Rather, a combination of improved use of grids, on transmission and distribution level, regional cooperation and demand side flexibility can provide for more system balancing at zero emissions and lower cost. This, of course, requires robust policies to activate the demand side in order to smartly integrate electric vehicles and heat pumps as major new sources of clean flexibility (known as "smart electrification").

Finding 5: Interdependency between national power systems should deepen, with benefits shared by all

The report adds to the evidence that sharing resources across borders substantially reduces costs. Scenarios that assume failure to advance regional cooperation add up to +3.4bn EUR of additional costs in 2030.

The findings confirm the importance of advancing on regional cooperation and governance as proposed in the Clean Energy Package, which goes beyond the current regime of voluntary cooperation amongst national system operators. A narrow, national perspective on power system security clearly comes with additional cost.

Acknowledgements

Cleaner, Smarter, Cheaper: responding to opportunities in Europe's changing energy system is the latest report in the Energy Union Choices series. The report builds on the understanding of the long-term implications of the energy transition established in the Roadmap 2050 reports and it aims to provide practical, independent and objective analysis. It is focused on the next set of infrastructure choices needed to accelerate the transition to a low carbon economy in line with the energy security, environmental and economic goals of the European Union.

This study was developed by the partners of the Energy Union Choices consortium; the European Climate Foundation (ECF), E3G, WWF, the Regulatory Assistance Project (RAP) and the Buildings Performance Institute Europe (BPIE), in cooperation with Artelys who carried out the quantitative analysis using their energy system optimization model. All of the assumptions, as well as the different scenarios used in this study were developed in close dialogue with an advisory group of companies, academics and NGOs. The Energy Union Choices consortium wishes to thank these companies and organisations: ABB, Alliander, the Clingendael International Energy Programme (CIEP), Elia, E.ON, the European Renewable Energies Federation (EREF), Ørsted (former DONG energy), the Renewables Grid Initiative (RGI), REstore, the Smart Energy Demand Coalition (SEDC) and Siemens Gamesa Renewable Energy, as well as the European Commission DG Energy, the Danish Energy Association, SolarPower Europe, The European Heat Pump Association (EHPA) and WindEurope for the valuable feedback they have provided to the project.

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

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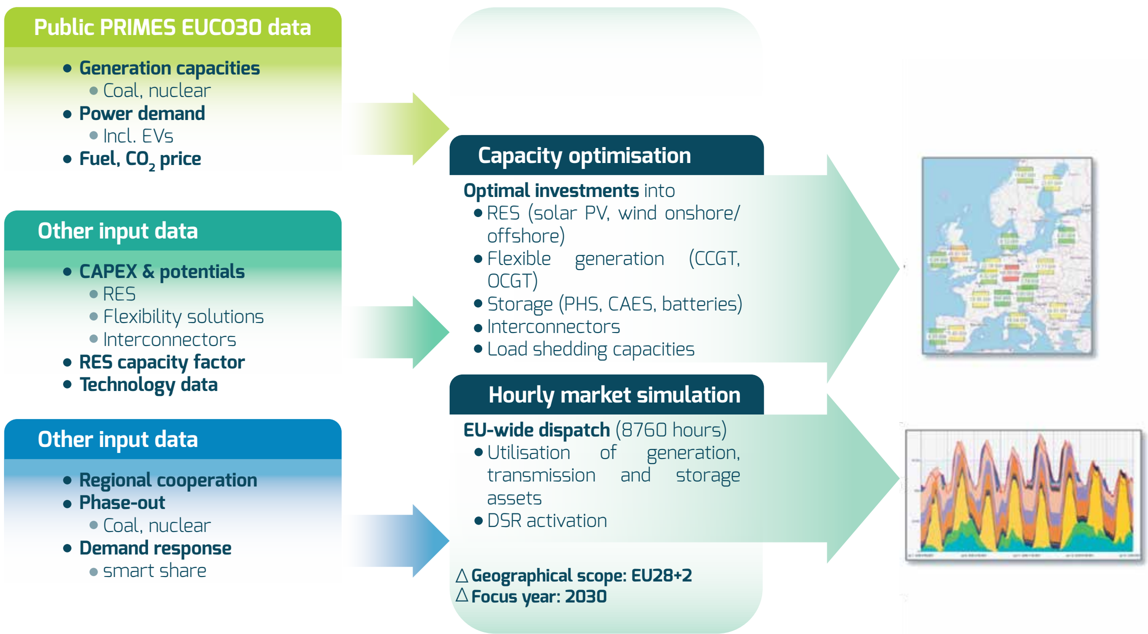
1. Technical analysis

1.1. Methodology

The analysis is based on the Artelys Crystal Super Grid[5] software application. Artelys Crystal Super Grid uses a bottom-up multi-energy model that allows for a joint optimisation of investments and of the management of the energy system assets using an hourly time resolution (assuming perfect market functioning) and covering the EU28 plus Norway and Switzerland.

Figure 1: Summary of the Artelys Crystal Super Grid model



[5] https://www.artelys.com/en/applications/artelys-supergrid

In terms of results, Artelys Crystal Super Grid computes capacity investments, the hourly dispatch (i.e. demand side response and storage activation, interconnection use and generation mix, plus related fuel demand), resulting emissions and related investment and operation costs. A post-processing of the results provides additional insights into employment impacts and non-CO2 emissions. A more detailed description of Artelys Crystal Super Grid (in particular in terms of data) is provided, separately from this report, in Annex 1.

Key assumptions

The European Commission's PRIMES EUCO30[6] scenario serves as the point of departure for this study as this scenario was used to conduct the impact assessments for the Clean Energy Package (CEP). Where public data was lacking, it was complemented through public sources and additional scenario specific assumptions. In contrast to the EUCO30 scenario published in early 2017, the study considers updated energy context data, which include the latest credible assumptions on the development of clean energy technology costs towards 2030, with updated capacity factors for renewable energy and updated assumptions on the Weighted Average Cost of Capital (WACC).

WACC: updated WACC figures are based on an internal assessment integrating public sources[7] and range between 5.0% and 7.0% (depending on the country) for investments in RES. The WACC for investments in thermal capacities and other assets is assumed to be one %-point higher. A WACC of 6.0% is considered for interconnectors. PRIMES EUCO30 values[8] by contrast range between 7.5 and 8.5%.[9] A detailed list of the WACC per country assumed in this report is given in Annex 2.

CAPEX: the analysis takes the following assumptions on average capital expenditures (CAPEX) for the investment in and connection of renewable energy sources' (RES) capacities between today and 2030[10]:

- Solar PV: 550€/kW, based on ETIP-PV estimate[11] for industrial PV in 2025
- Wind onshore: 1,350 €/kW, based on JRC's ETRI report[12]
- Wind offshore: 2,150 €/kW, based on Danish Energy Agency's estimate[13] for 2020/2030

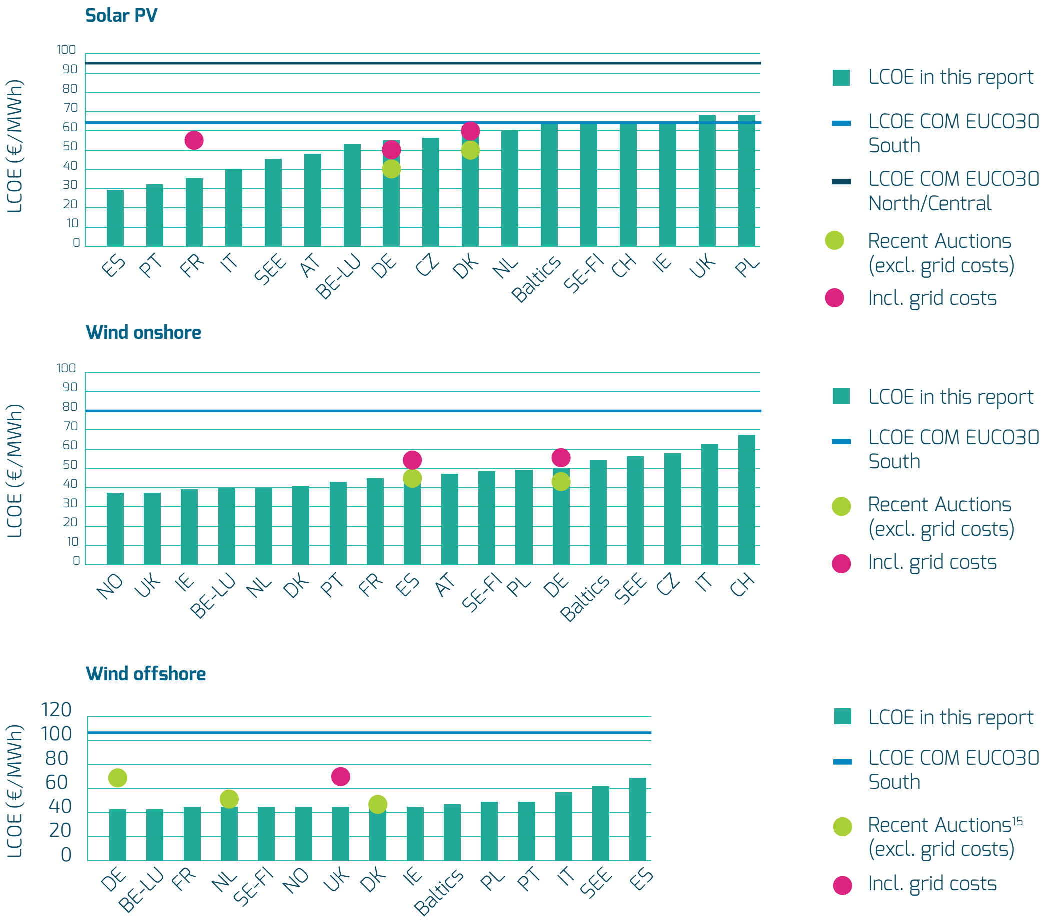
Capacity factors for new wind power plants were likewise updated in order to take into account the latest developments in turbine design:

- Onshore wind capacity factor increase of about 50%, as stated by JRC ETRI, and applied to current PRIMES capacity factors
- Offshore in Baltic/North Sea and North Atlantic: 50% (based on DEA report and feedback from project developers)
- Same capacity factor for solar PV as under PRIMES

[6] The EUCO30 scenario assumes that all 2030 targets set by the European Council (a 27% share of renewable energy and a 40% reduction in greenhouse gas emissions from 1990 levels), as well as the 30% energy efficiency proposed by the European Commission are met; further details: https://ec.europa.eu/energy/sites/ener/files/documents/20170125_-_technical_report_on_euco_scenarios_primes_corrected.pdf
[7] DiaCore project: http://diacore.eu/images/files2/WP3-Final%20Report/diacore-2016-impact-of-risk-in-res-investments.pdf, and Towards2030 project: http://towards2030.eu/sites/default/files/Impacts%20of%20electricity%20design%20trends%20on%20RES%20pathways.pdf
[8] https://ec.europa.eu/energy/sites/ener/files/documents/ref2016_report_final-web.pdf
[9] The PRIMES discount rate (which reflects various risk factors) for regulated monopolies, grids and RES investments under feed-in tariff or contract for difference is equal to 7.5%; the discount rate for companies in competitive energy supply markets and RES investments under feed-in premium, RES obligation or quota system with certificates is equal to 8.5%.
[10] The modelling focusses solely on the year 2030, yet additional capacities need to be installed over the course of the entire projection horizon between today and 2030. This is why we apply averaged CAPEX data.
[11] http://www.etip-pv.eu/fileadmin/Documents/ETIP_PV_Publications_2017-2018/LCOE_Report_March_2017.pdf
[12] https://setis.ec.europa.eu/system/files/ETRI_2014.pdf
[13] https://ens.dk/en/our-services/projections-and-models/technology-data
[14] https://ec.europa.eu/energy/sites/ener/files/integration_of_primes_scenarios_into_metis.pdf

All cost assumptions were benchmarked with the latest auction results to ensure that robust estimates are used in this study. Figure 2 provides an overview of the resulting LCOEs obtained with the updated capacity factors (including costs for grid connection) by RES technology and country and compares them with the ones adopted in EUCO30 (lines) and the latest auction results (dots).

Figure 2: LCOE by technology and country, compared to EUCO30 and latest auction results



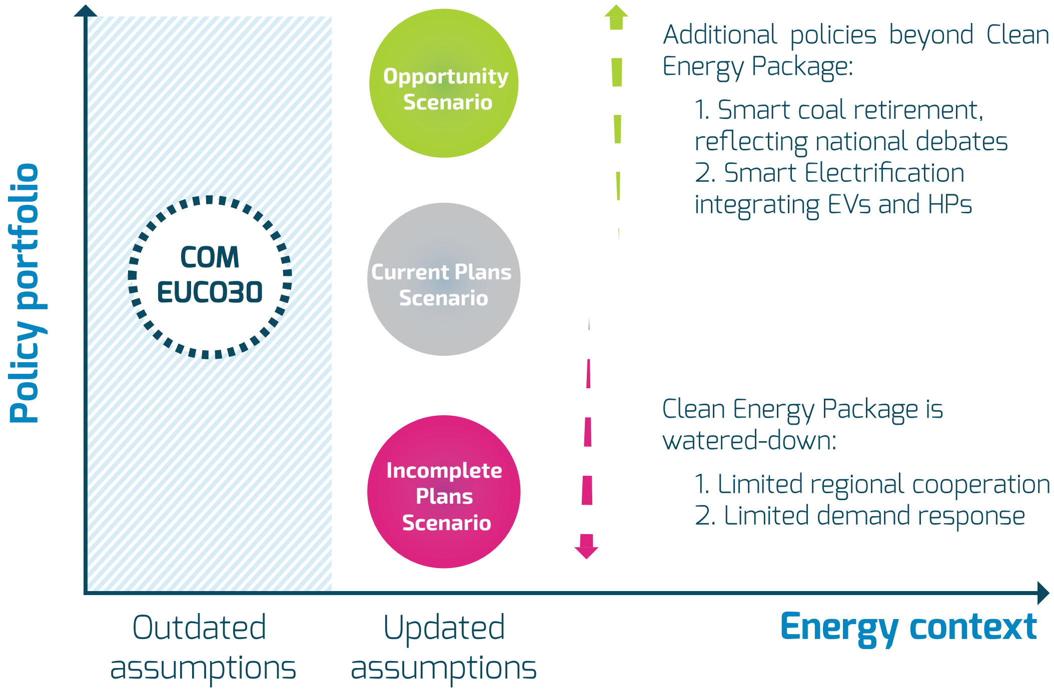
Carbon price and fuel costs: the analysis did not make any changes to the Commission's EUCO30 scenario: the CO_2 price is equal to 27 EUR/t. This is at the higher end of carbon price projections by market analysts anticipating the now agreed further reform of the EU ETS.[16]

Transmission data: The optimisation of investments in interconnector capacities between core countries and regions relied on the TYNDP project list, but was limited to projects "under design and/or permitting" and some "under planning", taking into account the project specific investment costs given by the TYNDP.

Consumption data: the analysis maintained the annual electricity demand data given by EUCO30. The electricity demand for electric vehicles (EV) was extracted from EUCO30 datasets and subsequently transformed into an EV stock. See Annex 2[17] for overall stock numbers per country and underlying assumptions for EV modelling, as well as assumptions on heat pumps and boilers.

[15] The 0 bids in German offshore auctions where translated into expected market prices for the time of operation.
[16] IETA GHG Market Sentiment Survey predicts an average price of EUR16/tCO_2 in phase 4 (2021-2030); Poll from Carbon Pulse in July 2017 with the main carbon market analysts shows a median expected carbon price of EUR 25.50/tCO2 in 2030, http://carbon-pulse.com/37341/
[17] The annexes to this report are available online in the "In-depth overview of the methodological approach and assumptions" document at http://www.energyunionchoices.eu/reports/

Figure 3: Scenario configuration



Scenario configuration and related policy assumptions

The analysis presents a picture of the European power sector in 2030 along three distinct scenarios, all of which were built using the updated energy context described in the previous section, but each representing different levels of policy ambition:

1. The ***Incomplete Plans Scenario*** (IPS) looks at a future where current plans for enhanced regional cooperation and demand side flexibility, as proposed under the revision of the electricity directive as part of the EU Clean Energy Package, are not delivered upon. It reflects:
   a. a national approach to generation adequacy (considering net transfer capacities where applicable[18]) and reserve procurement;
   b. a national planning of RES investment, assuming that domestic RES resources can only be exploited on a national level;
   c. variable RES capacities are not eligible to participate in the balancing market;
   d. Demand Side Response (DSR) deployment for reserve and day-ahead markets being restricted to countries already providing market access today.

   A detailed overview of the calculation procedure that was used to take these different constraints into account is given in Annex 1.

[18] Based on ACER market monitoring report: http://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-edition.aspx

2. The ***Current Plans Scenario*** (CPS) represents full delivery of regional cooperation and demand side flexibility measures, as proposed in the Clean Energy Package, thus mirroring the European Commission's own impact assessment of these plans. In modelling terms, this translates into full consideration of interconnectors for generation adequacy, reserve sharing and RES exploitation at a regional level. In terms of DSR, it is assumed that the full industrial load shedding potentials and 25% of the industrial/commercial load shifting potential is available, while decentralised residential and commercial consumers are assumed to be merely involved via implicit demand response, e.g. triggered through static time-of-use tariffs. The major benefit of the *Current Plans Scenario* lies in its ability to reflect the extent to which RES uptake can be increased due to the updates of WACC, CAPEX and capacity factor data in comparison to the EUCO30 scenario.

3. The ***Opportunity Scenario*** (OS) assesses the impact of two additional policy levers that go beyond the content of the Clean Energy Package. Both these levers were also tested as individual sensitivities (further referred to as DSR-only and RETIRE-only).

    a. A step change in decentralised demand response policies and distribution grid management, reflecting what would constitute a "smarter" future with ambitious integration of real-time pricing (RTP) for heat pumps and electric vehicles and a long-term grid planning strategy.

    i. **Enhanced deployment of decentralised DSR:** instantaneous consumer reactions to time-varying electricity tariffs (RTP that reflects the hourly variation in wholesale market prices) and the roll-out of intelligent infrastructure for communication and automation among a substantial share of decentralised residential and commercial consumers:

    1. 50% of industrial and commercial load shifting potential is exploited
    2. 60% of all consumers with boilers, heat pumps rely on RTP tariff
    3. 50% of all EVs (and they may perform Vehicle-to-grid (V2G) functions and access the reserve market)

    ii. **Smart distribution grid planning and operation:** The Opportunity Scenario assumes anticipatory distribution grid planning, removing all bottlenecks in the grid connection process, thus allowing for unconstrained deployment speeds. It also allows for grid-related curtailment of the upper 20% of solar PV generation peaks. This translates into reduced PV grid connection costs, lowering the overall CAPEX of PV by 7%, while reducing PV generation by merely 2.5%.

    b. The retirement of coal and nuclear capacities beyond what was forecasted in EUCO30, reflecting existing debates and recent retirement announcement in a number of Member States, in addition to no new coal and lignite power plants being built from 2015 onward across the EU.

Figure 4: Coal, lignite and nuclear capacity reductions considered in the *Opportunity Scenario*

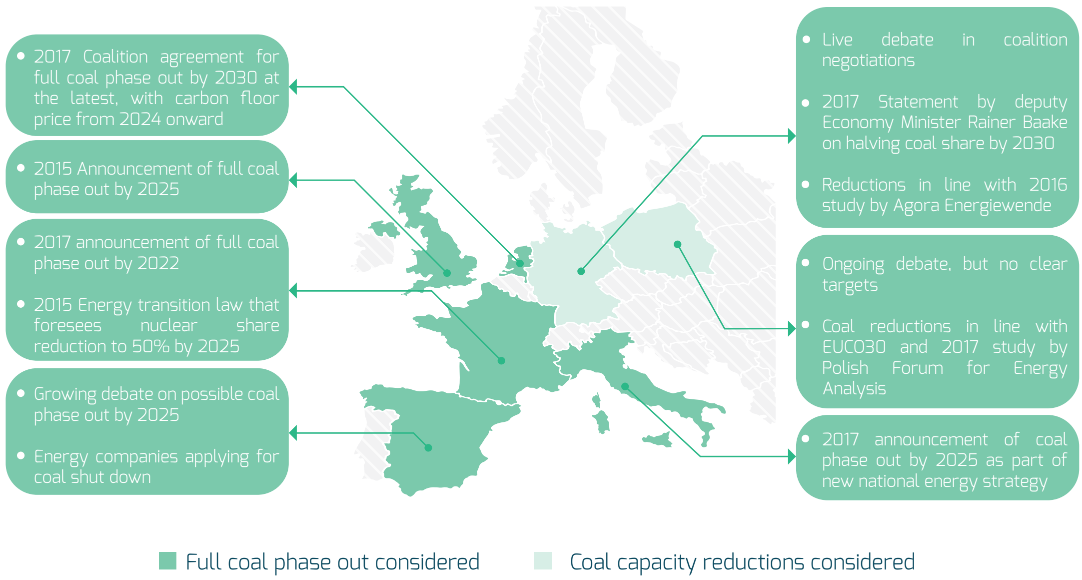
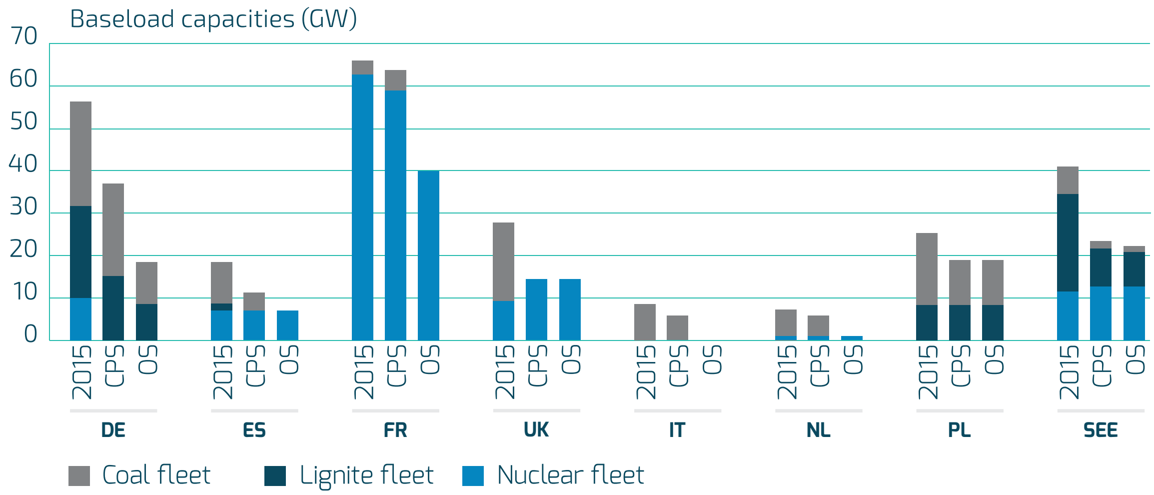


Figure 5 shows a detailed breakdown of the reductions in coal, lignite and nuclear capacities in the *Opportunity Scenario*, compared to the *Current Plans Scenario* (which uses EUCO30 capacities) and 2015. In total, the *Opportunity Scenario* assumes a reduction of 37 GW of coal and lignite capacity (from 99 to 62 GW) and 20 GW of nuclear capacity (from 112 to 92 GW) compared to EUCO30 and the *Current Plans Scenario*. In comparison with 2015, these capacities drop from 289 GW in 2015 to 153 GW under the *Opportunity Scenario* (-47%).[19]

Figure 5: Coal, Lignite and Nuclear capacities in 2015, the *Current Plans* and the *Opportunity Scenario*.



[19] Annex 2 provides a list of baseload capacities for all core countries and regions and is available online in the "In-depth overview of the methodological approach and assumptions" document at http://www.energyunionchoices.eu/reports/

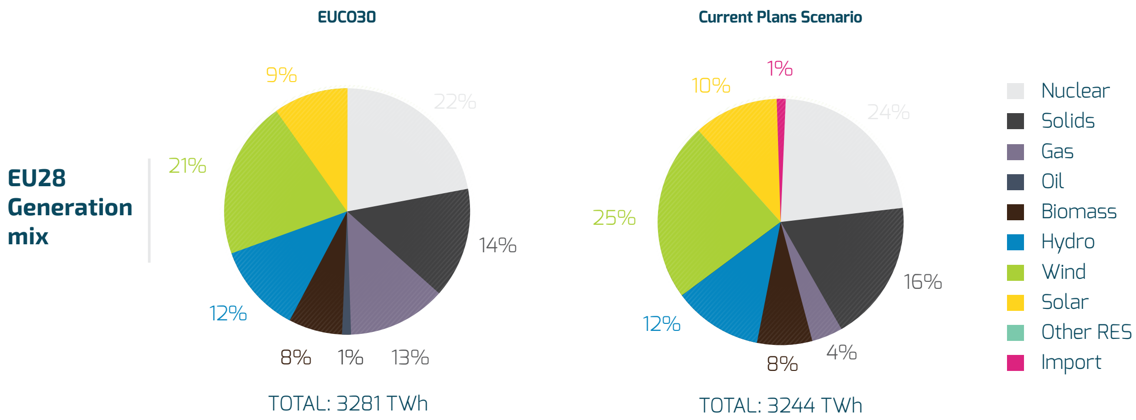
1.2. Overview of findings

1.2.1. The new energy reality comes with new opportunities, but current plans fall short of tapping into the potential

The *Current Plans Scenario* reveals that the new energy context (updated WACC, CAPEX, capacity factors) provides an opportunity for the Clean Energy Package to have more impact in terms of the uptake of renewables in and decarbonisation of the power sector.

The share of renewable electricity in the Current Plans Scenario increases to 55% (from 29% today), which is 6% above what was projected in EUCO30, while carbon emissions attain a level of 560 Mt, 24% below the EUCO30 level.

Figure 6: At a glance: a comparison of the power sector in the *Current Plans Scenario* and EUCO30

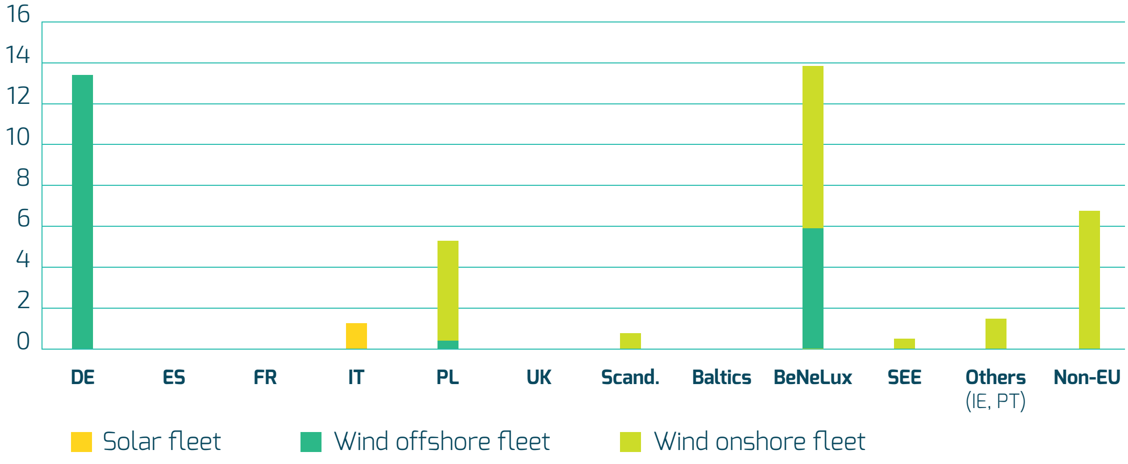


	EUCO30	Current Plans Scenario
RES-E	49%	55%
Emissions	735 Mt Co_2	560 Mt Co_2

In the *Current Plans Scenario*, an additional 42 GW wind (22 GW of wind onshore, 19 GW of wind offshore) are installed in Germany (+13 GW of offshore capacities), the Benelux countries, Poland and Scandinavia. For Solar PV installations, the uptake is limited to 1 additional GW in Italy.

Further PV investments do not materialise as the EUCO30 scenario already reaches, in most southern countries, the maximum PV deployment speed, assumed in the *Current Plans Scenario*. See Annex 2 for more details on the LCOEs by technology and the respective investment potentials.

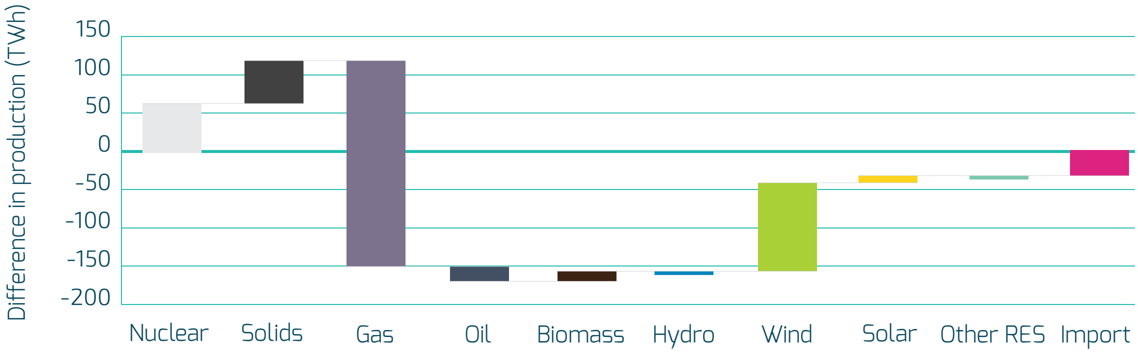
Figure 7: Change in RES generation capacities in the *Current Plans Scenario*, compared to EUCO30



Looking at changes in power generation (cf. Figure 8), the analysis finds that wind substitutes natural gas as the utilisation of wind in combination with gas is cheaper than the exclusive construction and utilisation of gas power plants. This means that the recent reductions in wind costs, which place their LCOE below the marginal generation costs of existing gas plants, are a real game changer. In total, more than 25% of gas-based power generation under the EUCO30 scenario is replaced by wind generation.

The graph also shows that lignite generation increases while gas generation declines drastically. It leads to the conclusion that it is unlikely that a carbon price of 27 EUR/t will make existing coal generation uncompetitive in the market vis-à-vis cleaner alternatives.

Figure 8: Change in net power generation under the *Current Plans Scenario*, compared to EUCO30 for the EU28[20]

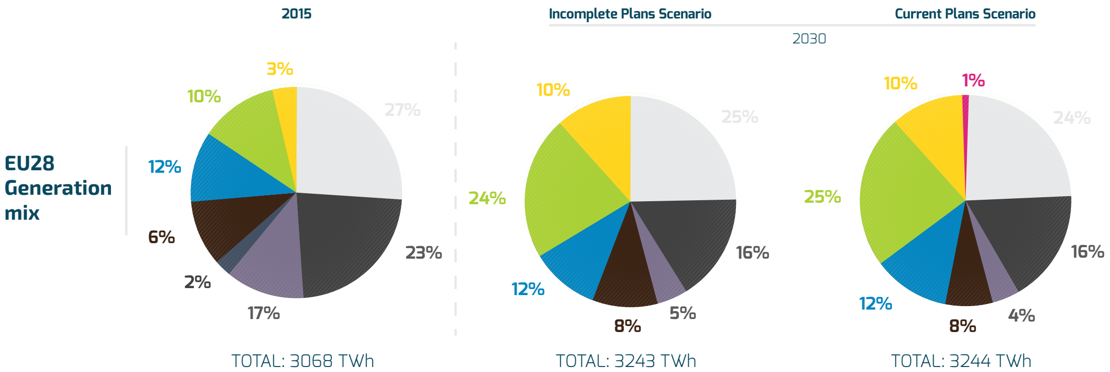


[20] It should be noted that the power generation given for the EUCO30 scenario was converted into net generation for reasons of comparability. In addition, the overall delta in power generation between both scenarios (linked to different temperature data) was deduced from the overall gas-based power generation

What if the Clean Energy Package is watered-down?

The significance of the Clean Energy Package becomes particularly clear from a cost point of view. When compared to the *Incomplete Plans Scenario*, the analysis finds slightly lower renewables uptake and less emission reductions at a higher overall system cost of 3.4 bn€.

Figure 9: At a glance: a comparison of the power sector in the *Current Plans Scenario* and the *Incomplete Plans Scenario*



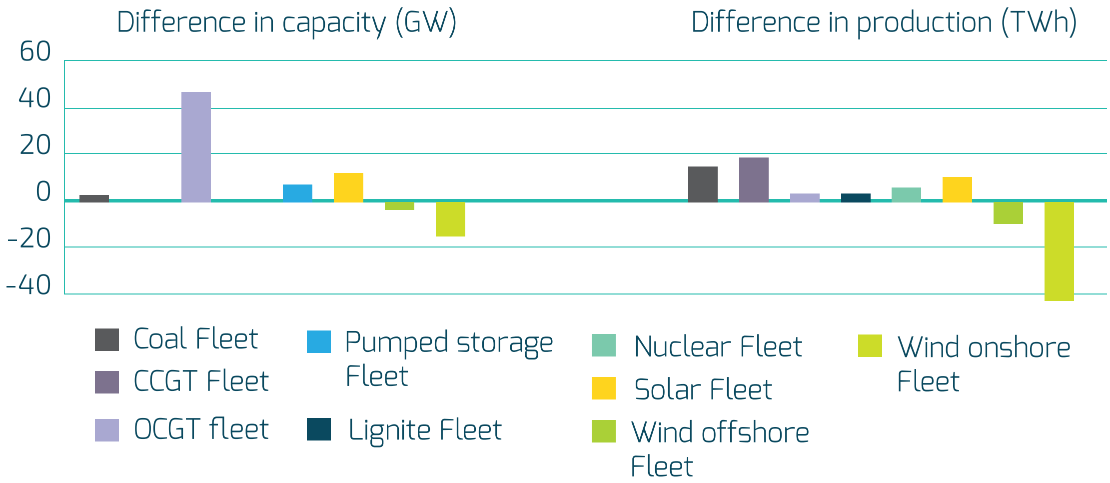
	2015	Incomplete Plans Scenario	Current Plans Scenario
RES-E	29%	54%	55%
Emissions	1060 Mt CO_2	584 Mt CO_2	560 Mt CO_2
System cost	N/A	+3.4 bn EUR compared to Current Plans Scenario	-

Nuclear | Solids | Gas | Oil | Biomass | Hydro | Wind | Solar | Other RES | Import

The absence of cooperation between Member States in this scenario, for generation adequacy, reserve procurement and exploitation of RES potentials, and the limitations to demand side flexibility have three major effects:

(1) **Additional generation capacity**: 43 GW of new gas turbines and 6 GW of pumped hydro storage have to be installed to ensure generation adequacy with a purely national approach. In turn, this reduces the demand for additional interconnectors (-6 GW), see left part of Figure 10.

Figure 10: Differences in capacity and power production between the *Incomplete Plans Scenario* and the *Current Plans Scenario*



(2) Instead of exploiting low-cost potentials first, using a cross-border European perspective, Member States solely consider RES potentials within borders. This represents **lost opportunities for investments in low-cost RES**. In countries/regions with limited wind energy potentials, investments in solar PV are found to increase by around 7 GW compared to the Current Plans Scenario (in particular in the Benelux region and Portugal), replacing 12 GW of onshore and 1.5 GW of offshore wind capacity in other countries/regions, such as the Netherlands, Scandinavia or Ireland. This means low-cost onshore wind (LCOE of about 40 €/MWh) is substituted by domestic solar PV and wind at a higher average LCOE of respectively 46 €/MWh and 59 €/MWh. In total this is equal to an increase in LCOE of 9 €/MWh and, in terms of generation, this translates into a net drop in RES generation of more than 40 TWh (or 3.6%) compared to the *Current Plans Scenario* (cf. right side of Figure 10). The resulting gap in generation is offset by higher gas and coal generation.

(3) Not having cross-border reserve sharing, combined with the limited access of DSR and decentralized storage to reserve markets, results in the need for **9 GW of additional reserve from thermal units and hydro assets** (pumped storage and reservoir), which reduces their availability for power generation or arbitrage on energy markets.

Overall, the *Incomplete Plans Scenario* still leads to a remarkable increase in RES generation compared to EUCO30. This again confirms that the new energy reality already changes the picture in any policy constellation. Yet it comes at high costs for the consumers.

The additional +3.4 bn€ annually compared to the *Current Plans Scenario* breaks downs as follows:

- Investments into additional gas capacities and pumped hydro storage to ensure generation adequacy plus the investments in additional PV (+3.4 bn€) outweigh the savings of avoided investments in wind (-2.0 bn€).
- Enhanced utilisation of thermal plants drives up the fuel costs by 2.4 bn€.
- The increase in fuel and fixed costs amounts to 3.8 bn€, which is merely reduced through avoided investments in additional interconnector capacities worth around 0.4 bn€.

To sum up, the report finds that the Clean Energy Package plays a critical role in keeping the costs of the power sector transition in check. However, it falls short of tapping into the potential that comes with the game-changing cost reductions in renewable technologies and does not tackle the issue of cheap existing coal capacity winning in the merit order. This begs the question what additional levers are needed to unlock the full economic and climate benefits from the technology cost revolution.

1.2.2. A portfolio of additional measures is needed to tap into the opportunities provided by low cost clean technologies

This section looks at a more complete policy portfolio, adding two levers that explore the benefits from lower technology costs, summarised in the *Opportunity Scenario*. The report identifies these levers as (1) tackling the issue of overcapacity from coal and nuclear generation and (2) a step-change in demand response policies, combined with smart distribution grid planning, with a particular view on capturing the flexibility value of new, electrified and distributed loads coming from electric vehicles, heat pumps or industrial processes.

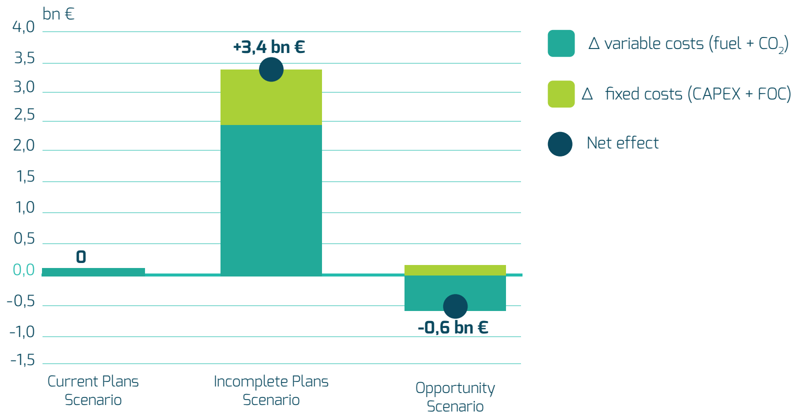
The assessment reveals that the impact of those two measures in combination represents a real breakthrough for the pace of the energy transition: Europe's power system can integrate more RES and reduce its emissions further and faster, compared to the *Current Plans Scenario*, at reduced overall system cost.

The opportunity for a faster transition at a lower cost

The *Opportunity Scenario* represents the most cost-effective pathway for the energy transition. While additional investments in renewable capacity and gas turbines drive investment and fixed costs up, a number of costs, such as maintenance, associated with nuclear and coal capacities, are avoided thanks to their early retirement. RES investments are made more cost-efficient due to DSR integration and, on balance, this leads to a net increase in fixed costs of around only 0.2 bn€ annually compared to the *Current Plans Scenario*. These additional fixed costs are further offset by the savings that the Opportunity Scenario generates in terms of variable costs: shifting power generation from lignite and coal to nearly zero marginal cost renewable and gas-based power generation implies annual savings of 0.8 bn€. In total, the *Opportunity Scenario* is found to generate annual savings of the order of 0.6 bn€.

Under the *Incomplete Plans Scenario*, by comparison, additional investments in gas-based back-up capacities and the intensified utilisation of existing gas plants push both fixed and variable costs up by 1.4 bn€ and 2.4 bn€, respectively. These costs are slightly alleviated through reduced investments in interconnector capacity (given the strong reliance on national assets), leading to a net cost increase of 3.4 bn€ annually compared to the *Current Plans Scenario*.

Figure 11: Change in system cost compared to the *Current Plans Scenario*



Technology specific findings

The main impacts on Europe's 2030 power system under the *Opportunity Scenario* compared to the *Current Plans Scenario* are threefold:

(1) Renewables make up for more than half of the phased-out generation

The assumed reductions of coal, lignite and nuclear capacities lead to a decrease of 310 TWh (-24%) in baseload generation with respect to the Current Plans Scenario. In order to replace this energy, the model can invest in new generation capacities (RES, gas-fired power plants), which can be accompanied by flexibility solutions, and can adapt the way already-installed capacities are operated.

The generation gap is found to be filled by up to nearly 60% of new investments in wind power (+131 TWh) and solar PV (+48 TWh). This leads to an overall RES share of 61% in net production for the EU28 (compared to 55% under the CPS). The remaining part comes from an enhanced level of gas generation (+126 TWh, cf. Figure 12).

Figure 12: Differences in power production and capacity between the *Opportunity Scenario* and the *Current Plans Scenario*

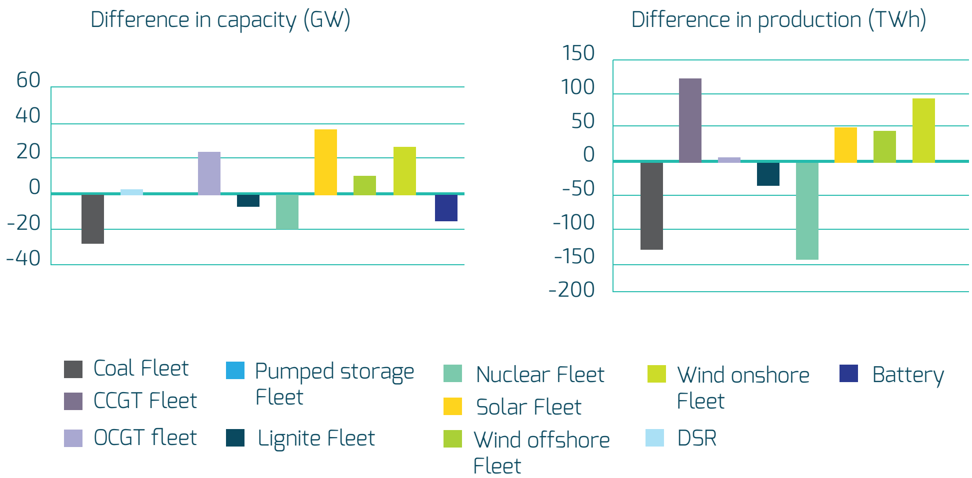
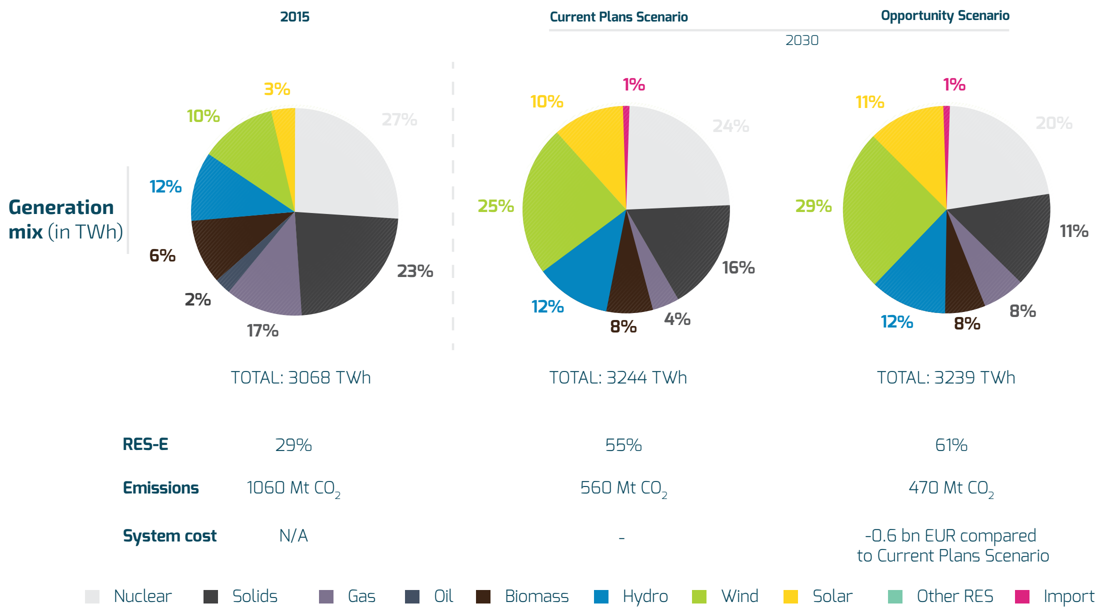


Figure 13: At a glance: a comparison of the power sector in the *Current Plans Scenario* and the *Opportunity Scenario*



This in turn reduces emissions by some additional 90 Mt CO2 (-16%) compared to the *Current Plans Scenario*, and -36% compared to EUCO30. Compared to 1990[21], the *Opportunity Scenario* brings the overall EU28 emission level down by around 70%.

That means the decarbonisation of the power sector can go beyond the trajectory outlined in the 2011 COM Low Carbon Economy Roadmap, which projects a range of -54 to -68% by 2030 compared to 1990. This is an important finding considering that the European Union will soon need to set itself more ambitious trajectories to 2050 in light of the well below 2 degrees and net zero objectives it agreed to in the 2015 Paris Agreement.

In terms of capacities, the removal of 57 GW of coal, lignite and nuclear capacity leads to new investments of 39 GW in wind power, 38 GW of solar power and 22 GW of additional OCGTs. As a result, existing CCGT capacities see their utilisation considerably increased under the *Opportunity Scenario* (utilisation doubles from 10 to 20%) so as to close the gap in power production.

2) Gas generation picks up but remains below EUCO30 and current levels

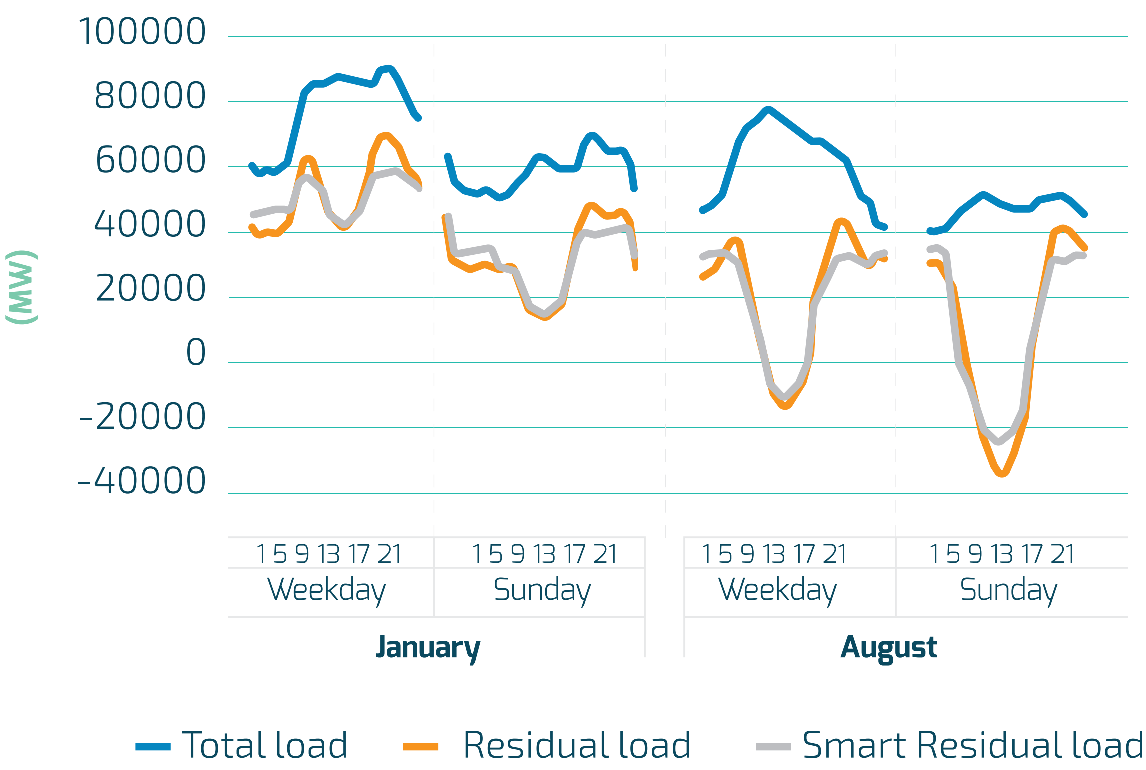
Compared to the *Current Plans Scenario*, gas generation nearly doubles (from 133 to 259 TWh). It is mainly existing CCGT capacities that see their utilisation considerably increased under the *Opportunity Scenario* (utilisation doubles from 10 to 20%) so as to close the gap in coal power production. Yet, in absolute terms, gas generation remains still far below the levels considered under the EUCO30 scenario (396 TWh) and amounts to a reduction of about 50% below 2015 levels[22]. This demonstrates that a phase-out of coal and reduction in nuclear capacities does not necessarily imply a higher gas demand (and thus import dependency) for the power sector compared to today, as long as adequate policies and measures are put in place to facilitate the partial replacement of baseload generation by renewable power generation. In particular, the deployment of DSR is found to play a key role to avoid baseload being predominantly replaced by gas-fired generation (see Section 1.2.3 on the impacts of isolated retirement strategies without accompanying demand side policies).

[21] 1990 and 2015 emissions data is based on the UNFCCC GHG inventory: http://di.unfccc.int/detailed_data_by_party; the emissions reported there and for the EUCO30 relate to the generation of power and district heat.
[22] http://ec.europa.eu/eurostat/statistics-explained/images/0/03/Gross_electricity_production_by_fuel%2C_GWh%2C_EU-28%2C_1990-2015-T1.png

(3) DSR reduces the need for gas turbines and stand-alone batteries while also optimising PV generation and investments.

Investments in more DSR help unlock PV investments, as DSR is able to provide the required flexibility to counterbalance the daily solar generation cycle. As indicated in Figure 14, especially in summer months, solar generation may exceed total hourly demand (see the blue curve illustrating the average German load on January and August days) and result in a surplus of renewable power (as illustrated, in orange, by the negative residual load during midday hours). The shift of EV power consumption, in particular battery charging of immobile vehicles for V2G on weekend days, and of industrial and commercial demand into these hours enables an enhanced utilisation of PV generation, reducing the overall generation surplus as illustrated by the grey line.

Figure 14: Averaged weekday residual load in Germany under the *Opportunity Scenario* for two different months: original and smart (i.e. after load shifting/shedding)



In contrast, when RES generation is low, or during demand peaks, DSR contributes to the shedding of the residual load peaks, thus replacing flexible gas generation. DSR is particularly useful during winter time, and even more so in countries with higher load levels due to electric heating, as illustrated by the blue curve, as it is a cost-efficient option to lower residual load peaks in early morning and evening times, just before and after solar PV injects electricity into the power system (see the orange peaks on January weekdays before and the flattened grey curve after DSR activation).

The model included the following end uses for DSR: heat pumps (whose operation can temporarily be interrupted), industrial load shedding, EV charging (where charging is postponed into later night time hours), vehicle-to-grid feed in and commercial DSR (e.g. through short term interruption of commercial cooling, ventilation or refrigeration) for very short residual demand spikes.

DSR also reduces the need for stand-alone batteries. As EVs become a component of the power system, their batteries can serve as storage units when vehicles are plugged in.

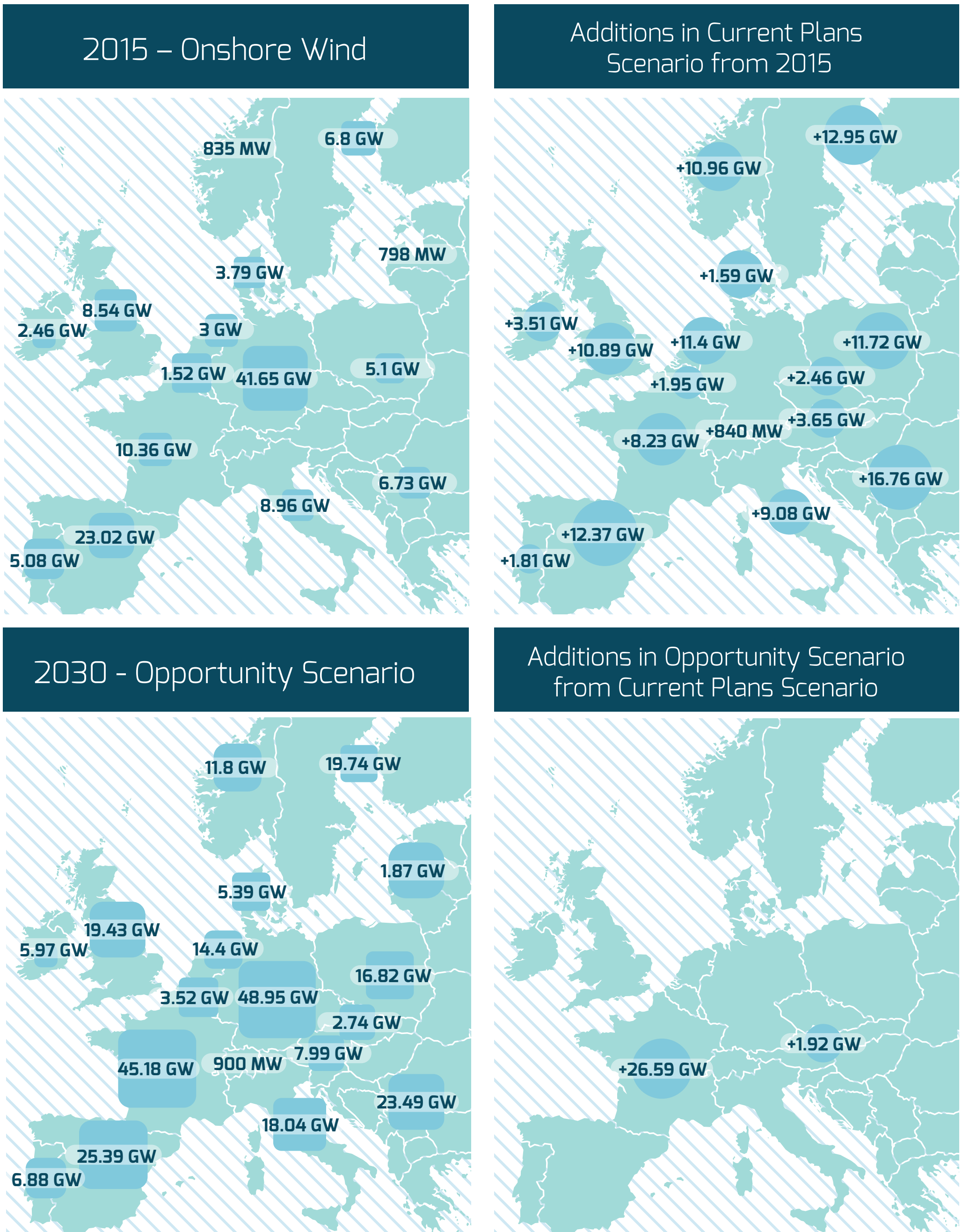
Moreover, DSR becomes an active contributor for reserve procurement, which reduces the need to invest in dedicated batteries (average contribution of batteries for reserve procurement is reduced from 6 to 3 GW between the *Current Plans* and the *Opportunity Scenario*). In total, DSR replaces the bulk of stand-alone batteries that are built under the *Current Plans Scenario*, as shown in Figure 12. Battery capacity drops from 22 to 6 GW and 1 GW of pumped hydro storage.

Geographical spread of RES investments

Under the *Opportunity Scenario*, the bulk of additional **onshore wind** capacities (+27 GW compared to the *Current Plans Scenario*) are added in France as the reduction in nuclear capacity creates space for new investments. By 2030, Germany, France and Spain host about 130 GW of the total 288 GW wind onshore capacity installed in EU28+2.

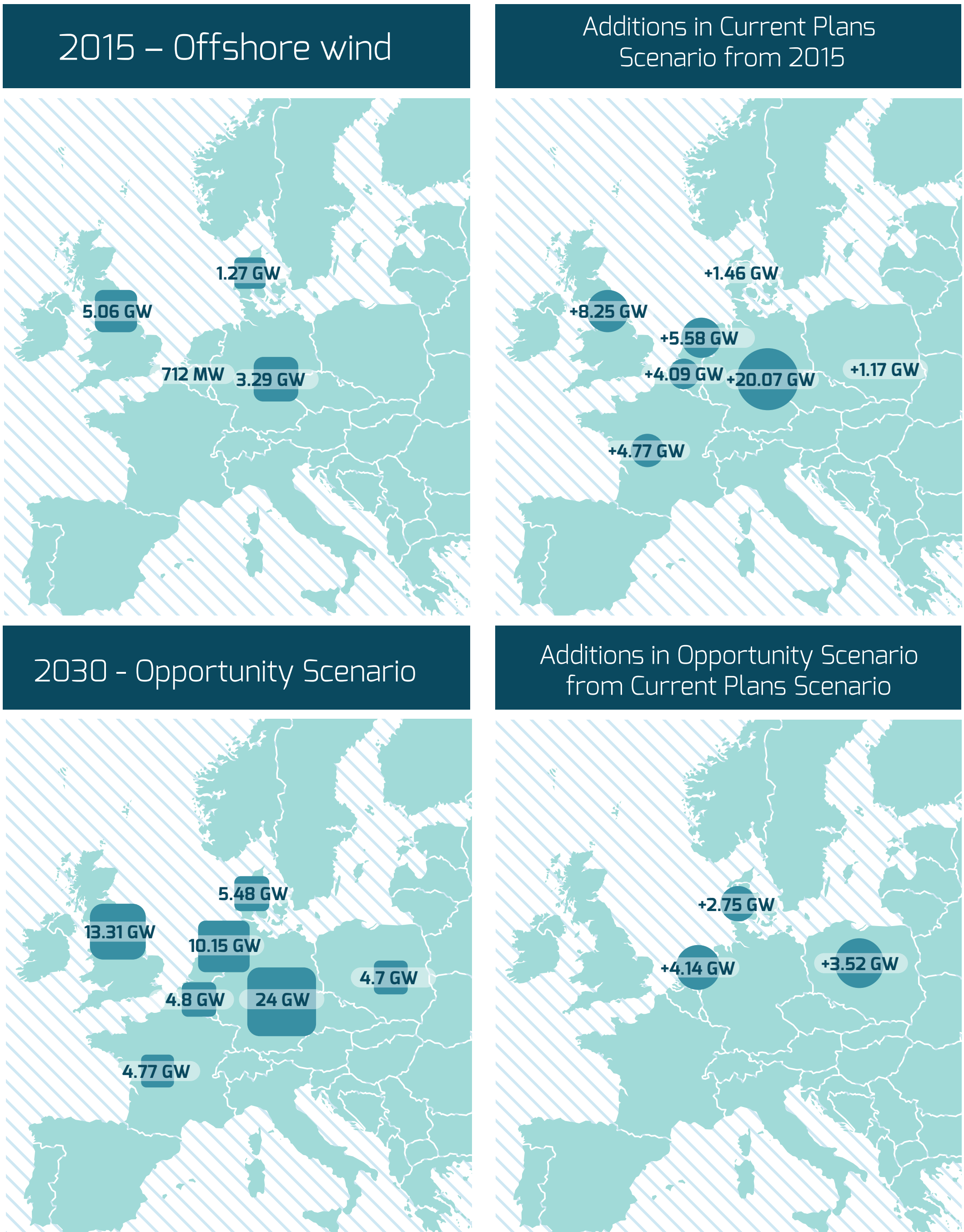
The analysis also confirms the major potential for cost-effective onshore wind in South Eastern Europe (+ 18GW compared to today).

Figure 15: Onshore wind capacities in the *Current Plans Scenario* and the *Opportunity Scenario*



In the modelling, the accelerated retirement of coal capacities in Germany, Poland, the Netherlands and France triggers some 10 GW of additional investments **in offshore wind** in the countries neighbouring Germany, such as the Netherlands, Denmark and Poland. This reflects a clustering of offshore wind potential around the North and Baltic Seas. By 2030, the overall installed offshore wind capacity reaches 68 GW, of which about two thirds are located in Germany, the UK and the Netherlands.

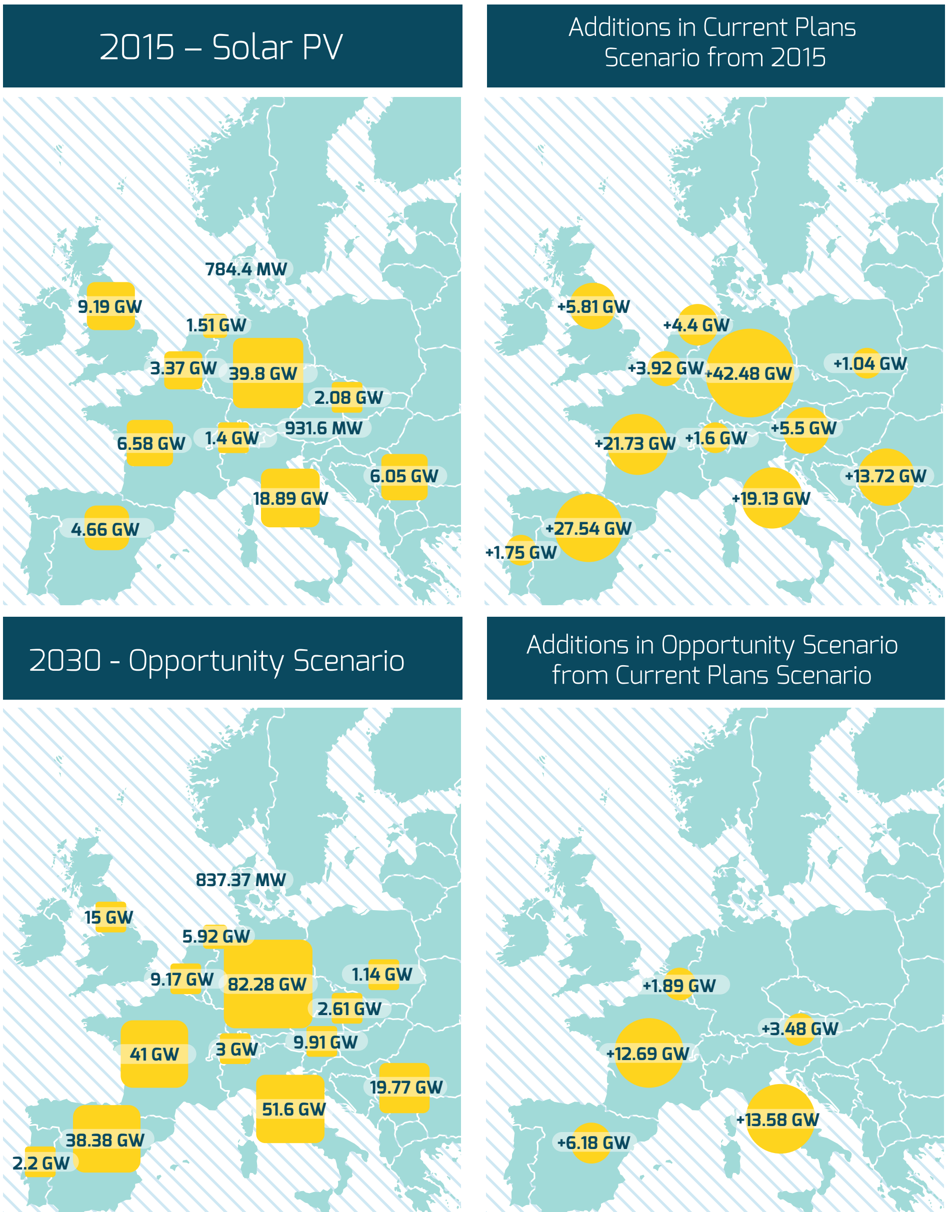
Figure 16: Offshore wind capacities in the *Current Plans Scenario* and the *Opportunity Scenario*



Under the *Current Plans Scenario*, the modelling would see **solar PV** investments concentrated in Southern and Central European countries, with major growth rates in countries like Spain, Austria or Poland. Yet the largest increase in absolute terms compared to 2015 occurs in Germany (+42 GW[23]).

The *Opportunity Scenario* reveals further investments in Spain, France and Italy. Enhanced system flexibility and the coal retirement are additional factors that drive the further PV growth in Central European countries with less favourable meteorological conditions, like Austria or Belgium. In total, 38 GW of capacities are added under the *Opportunity Scenario* compared to the *Current Plans Scenario*, leading to a total capacity of 283 GW in EU28+2.

Figure 17: Solar PV capacities in the *Current Plans Scenario* and the *Opportunity Scenario*



[23] This increase is already assumed under the EUCO30 scenario, which is set as minimum constraint for our own capacity investment optimisation.

Cooperation between Member States

Under the *Current Plans Scenario* interconnector capacities between Member States are reinforced by 40% (or 26 GW) compared to today's level (cf. Figure 18). This assumes the realisation of projects "under design and/or permitting" and some projects "under planning" in the current TYNDP project list.

The Opportunity Scenario reveals that, despite growing shares of renewables, no substantial grid capacities are added, provided existing capacity is optimally used. In total, electricity exchanges across the EU are identical in the *Current Plans* and the *Opportunity Scenario*. Compared to the overall power generation in EU28+2, about 15% is exchanged via European interconnectors[24] and

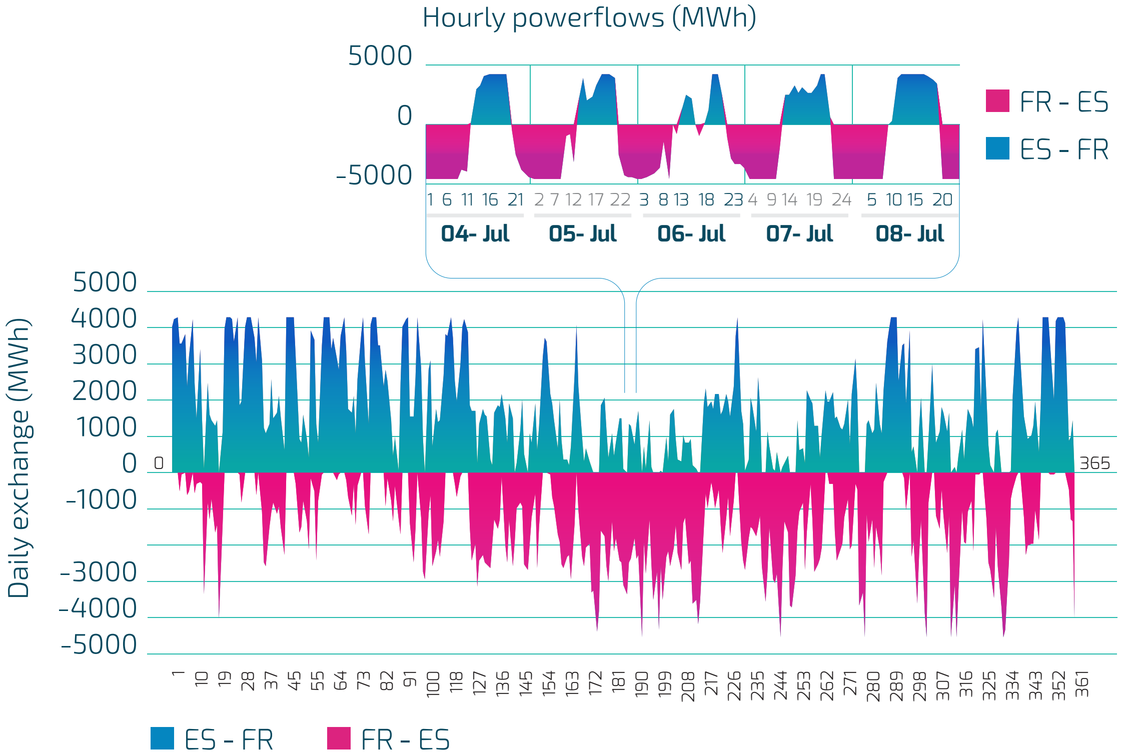
Figure 18: Interconnection additions in *Current Plans* and *Opportunity Scenario*, compared to today

about 7% is not consumed domestically but outside the country of origin.
While some countries or regions may become or remain overall net importers and others net exporters, the report's essential finding is that allowing for increased interdependency between national electricity systems comes with important collective benefits, since system security is maintained at significantly lower cost (up to 3.4bn EUR per year in 2030 across the EU).

This 'new normal' of interdependency is well captured in the next figure, which looks at the exchange flows between France and Spain (cf. Figure 19). It reveals that France and Spain exchange substantial amounts of electricity, with flows varying significantly throughout the year. In winter time, Spain exports electricity to help France cover its demand peaks, which are mainly driven by electric heating. In the summer months, both countries benefit from each other's low-cost electricity sources: France imports during Spanish low-cost PV generation during the day (and potentially transfers it to other

[24]This includes exchanges with transit countries.

Figure 19: Mean daily electricity exchange between France and Spain



1.2.3 The additional measures should be advanced in parallel

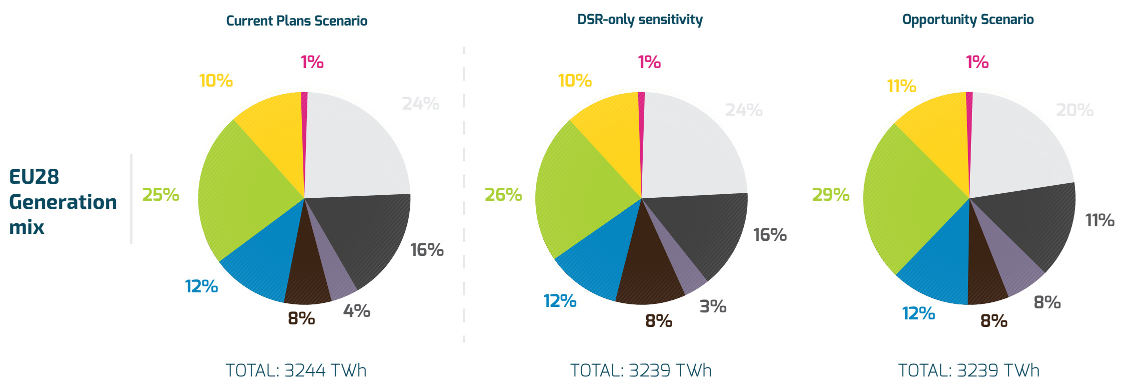
The *Opportunity Scenario* looks at two policy levers in addition to the Clean Energy Package modelled in the *Current Plans Scenario*. These are: (1) the smart retirement of coal (and nuclear in France) capacities, and (2) smart electrification via decentralised demand response policies and distribution grid management. The previous chapter examined the impact of these levers when applied in combination with one another. The study has, however, also analysed the impact of these policy levers when applied separately.

Implications of a sole focus on policies to unlock decentralised demand response at scale (DSR-only)

The *DSR-only* sensitivity has three major effects:

- Enhanced DSR deployment and unconstrained RES deployment speed allows for a higher uptake of solar PV and wind potentials in countries with needs for additional baseload (mainly in Italy, +14 GW PV, and France, +14 GW wind onshore). The additional RES generation impacts the utilisation of national base load capacities, e.g. in France, full load hours of nuclear capacities are reduced by 3%
- At the same time, DSR reduces the need for peak power capacity as load shifting represents a lower cost solution, thus preventing some 9 GW of additional OCGT capacities and reducing the utilisation of existing CCGT capacities by 21% and of coal capacities by 6% (cf. Figure 21).
- However, DSR also enhances the utilisation of lignite in some countries (e.g. German, Czech and Polish lignite go up by about 1%-point). For countries relying on carbon-intensive baseload (i.e. lignite), this translates into a net increase in carbon emissions (again, also due to the low carbon price that implies a coal-before-gas merit order).

Figure 20: At a glance: a comparison of the power sector in the *Current Plans Scenario*, *DSR-only* sensitivity and the *Opportunity Scenario*

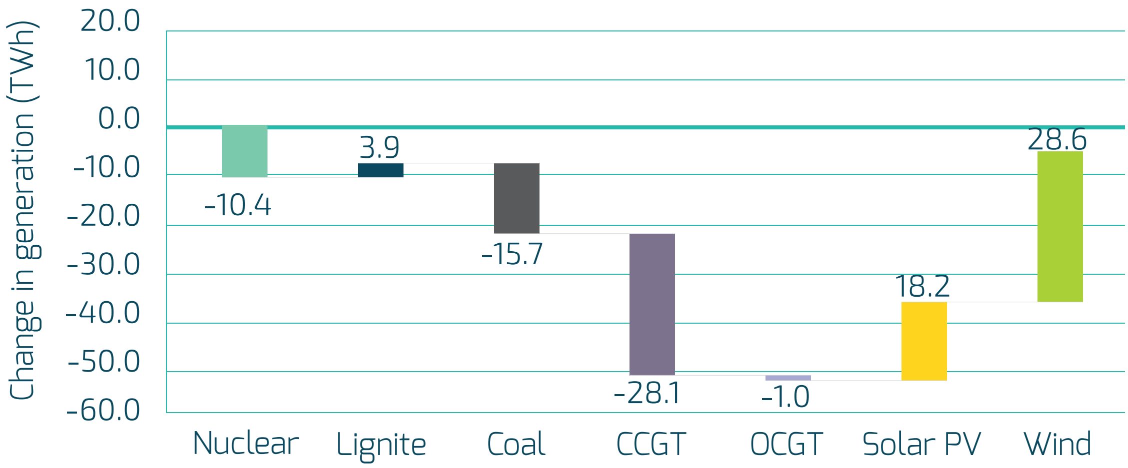


	Current Plans Scenario	DSR-only sensitivity	Opportunity Scenario
RES-E	55%	57%	61%
Emissions	560 Mt CO_2	538 Mt CO_2	470 Mt CO_2
System cost	-	-4.1 bn EUR compared to Current Plans Scenario	-0.6 bn EUR compared to Current Plans Scenario

Nuclear · Solids · Gas · Oil · Biomass · Hydro · Wind · Solar · Other RES · Import

The *DSR-only* Sensitivity reveals that a substantial cost reduction can be achieved due to the utilisation of cheap RES resources, enhanced baseload utilisation and avoided investments, and utilisation of peak load capacities (-4.1 bn€ compared to the *Current Plans Scenario*). At the same time, however, under this sensitivity, the RES share only rises by 2% and, more importantly, CO_2 emissions stay far from the level attained under the *Opportunity Scenario* (538 Mt vs 470), mainly due to an increase in lignite generation.

Figure 21: Change in generation between the *DSR-only* sensitivity and the *Current Plans Scenario*

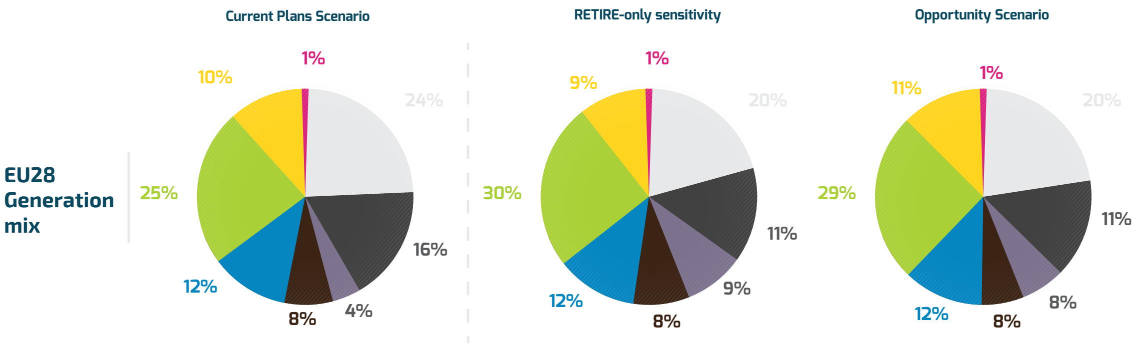


Implications of a sole focus on smart retirement from coal, lignite and nuclear

The second sensitivity assesses the impacts of an isolated focus on smart retirement (*RETIRE-only*) without a dedicated focus on smart electrification and demand side flexibility. As illustrated in Figure 22, this has two major effects:

- First, the phase out creates a market for additional RES capacity. However, as the required system flexibility for PV integration is missing, some of the low-cost PV potentials are not exploited.
- Secondly, over half of the retired coal and nuclear capacities are compensated by an increase in gas capacity (around 35 GW of new OCGT capacities is built) to compensate for the lack of demand side flexibility in this sensitivity. Still, the running hours of these new plants are very low. This comes with increases in cost.

Figure 22: At a glance: a comparison of the power sector in the *Current Plans Scenario*, *RETIRE-only* sensitivity and the *Opportunity Scenario*



	Current Plans Scenario	RETIRE-only sensitivity	Opportunity Scenario
RES-E	55%	60%	61%
Emissions	560 Mt CO_2	483 Mt CO_2	470 Mt CO_2
System cost	-	+4.7 bn EUR compared to Current Plans Scenario	-0.6 bn EUR compared to Current Plans Scenario

Nuclear, Solids, Gas, Oil, Biomass, Hydro, Wind, Solar, Other RES, Import

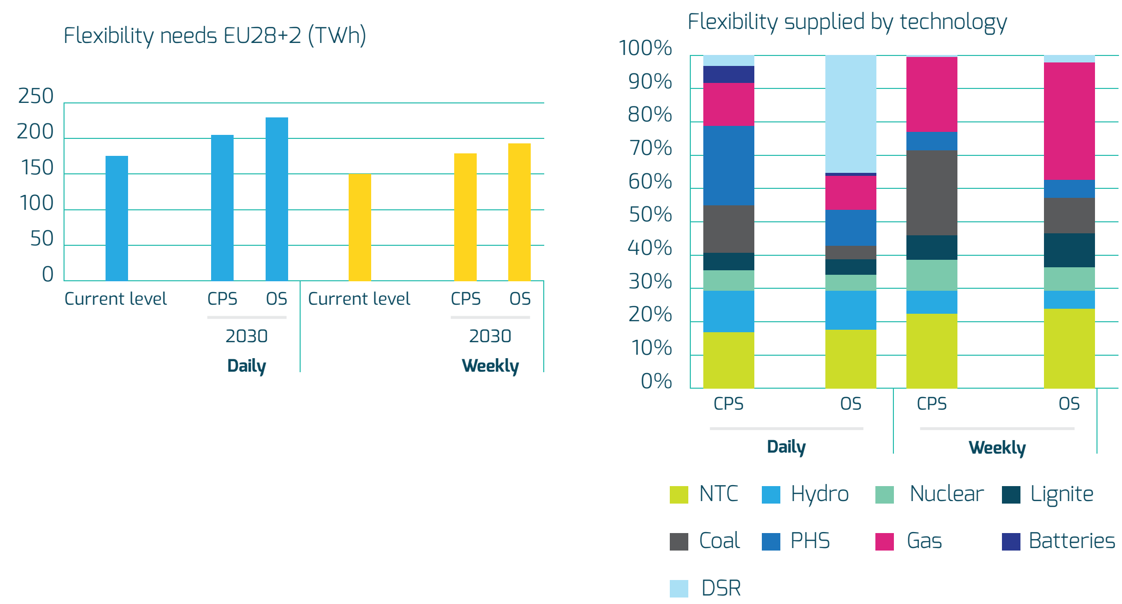
1.2.4 Demand side flexibility becomes a key source of flexibility

Rising shares of variable renewable sources in the European power mix imply additional needs for flexibility in the system. This flexibility is measured on a daily and a weekly scale and quantifies which technologies meet these needs in the future (Annex 1 explains how the needs are calculated).

In the first instance, flexibility is provided through reinforced interconnector capacities and enhanced regional market coupling, driving down the daily/weekly needs by some 18% to 25% and thus contributing substantially to the integration of vRES[25] technologies.

[25] Variable renewable energy source (i.e. wind power and solar PV)

Figure 23: Flexibility needs in EU28+2 and contribution to flexibility by technology



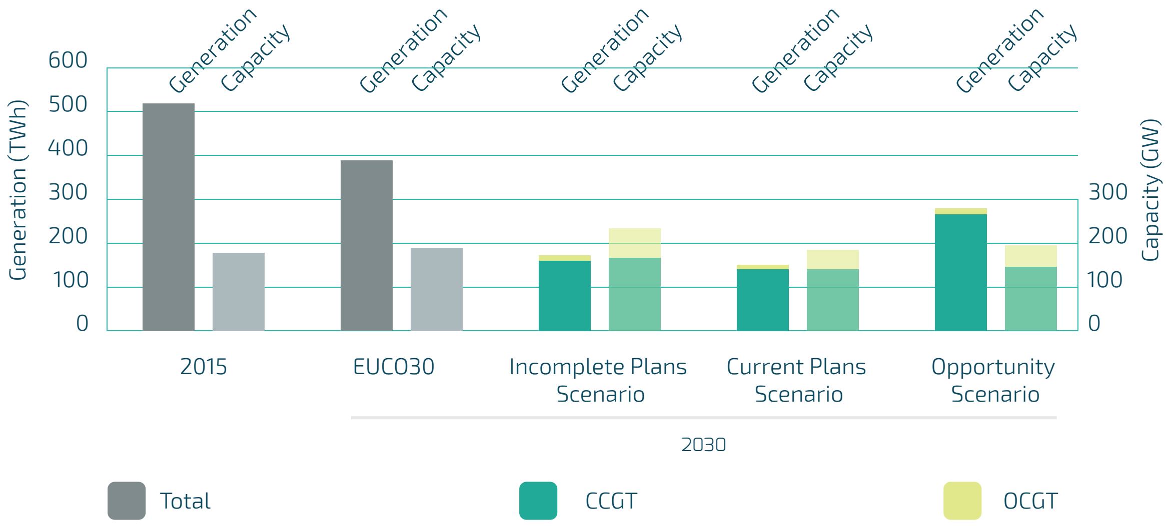
Under the *Current Plans Scenario*, the remaining **daily flexibility needs** are supplied by pumped hydro storage and hydro-based generation. Batteries replace part of the gas-based flexibility provision[26], yet the major part of batteries is used for reserve procurement. The comparison of the *Opportunity* with the *Current Plans Scenario* reveals that demand side flexibility takes the place of batteries (as battery storage capacity is available in electric vehicles) and compensates for the retirement-driven drop in flexibility supply from nuclear, lignite and coal capacities, while also reducing the contribution from pumped hydro storage (from 23 to 12%) and gas-based power generation (from 16 to 12%).

The picture is different for **weekly flexibility needs**: while the bulk of flexibility under the *Current Plans Scenario* is provided by coal and gas, the retirement of baseload and mid merit capacities further enhance the role of gas, whereas the contribution of DSR remains marginal on weekly time scales. This is related to the fact that demand side flexibility features by default only a rather limited capability to shift demand by more than 24 hours.

The study of daily and weekly flexibility needs and the way these are met reveals an increasingly important role for gas (between *Current Plans* and the *Opportunity Scenario*) to counterbalance renewable power generation while reducing coal capacity. This is why gas-based power generation nearly doubles. However, the overall gas-based generation remains below the projected level under the EUCO30 scenario and equals only half the current level (cf. Figure 24). As most additional gas generation comes from enhanced utilisation of existing CCGT capacities, additional investments remain limited to around 22 GW of gas peakers across Europe.

[26] This is revealed when contrasting the Current with the Incomplete Plans Scenario, which is not included in the chart.

Figure 24: Gas capacities and net gas-based power generation across the scenarios, compared to today and EUCO30



In terms of demand side flexibility, the analysis finds the bulk is provided by electric vehicles through temporal shifting of vehicle charging and the V2G storage functionality. Significant additional flexibility is provided by electric boilers (continuous throughout the year, yet limited to those countries exhibiting substantial boiler installations, such as France). Heat pumps (with major potentials being available in winter time), as well as commercial and industrial load shifting contribute to similar but minor shares (depending on the actual country).

In terms of capacity, the overall sum of maximal activation of flexibilities in the day-ahead market across all countries amounts to some 70 GW for all EU Member States.[27] The most effective lever is once again the reduction in EV charging load and parallel V2G infeed. As outlined above, the report assumes the smart integration of up to 50% of EVs, 50% of commercial and industrial load and 60% of boilers and heat pumps in the power system. Hence, while clearly requiring strong policies, there is room for additional improvement, which would drive further reductions in fossil based balancing on a daily and weekly basis.

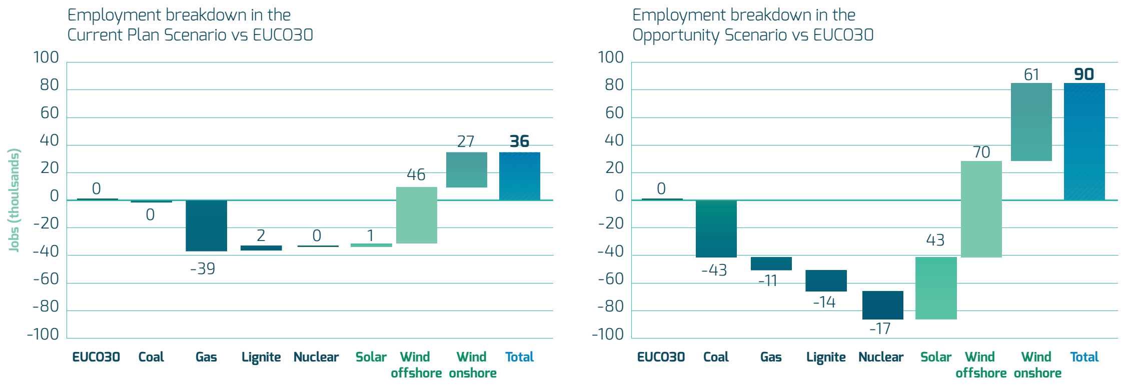
[27] This amount of maximal activation of demand side exceeds the value given in the Impact Assessment on flexibility, prepared by COWI, which is around 40 GW of incentive-based DSR (cf.:https://ec.europa.eu/energy/sites/ener/files/documents/demand_response_ia_study_final_report_12-08-2016.pdf). This can be explained by the fact that this study assumes twice as many heat pumps being activated for DSR than in the COWI report. In addition, the analysis includes V2G for electric vehicles, which further raises the flexibility potential as you can not only reduce demand from vehicle charging but also increase production through grid infeed from vehicles that were already charged before.

1.2.5 A faster transition increases jobs and improves health benefits

The shift from gas to wind power between the *Current Plans Scenario* and the EUCO30 scenario implies nearly 40,000 lost jobs[28] in gas power plants, but a simultaneous increase of about 73,000 jobs in the European wind power business. Hence, the 6% increase in RES share comes with 36,000 additional jobs (cf. Figure 25).

Under the *Opportunity Scenario*, the loss of jobs in the gas power sector is less pronounced due to the increases in gas generation, but the retirement of coal and nuclear capacities adds to the picture resulting in a total loss of 85,000 jobs related to conventional power generation. In contrast, however, more than twice as many new jobs are created around wind turbine manufacturing and the installation of new renewable generation sites, resulting in a net effect of 90,000 new jobs created.

Figure 25: Employment effects in *Current Plans Scenario* and *Opportunity Scenario* in comparison with EUCO30

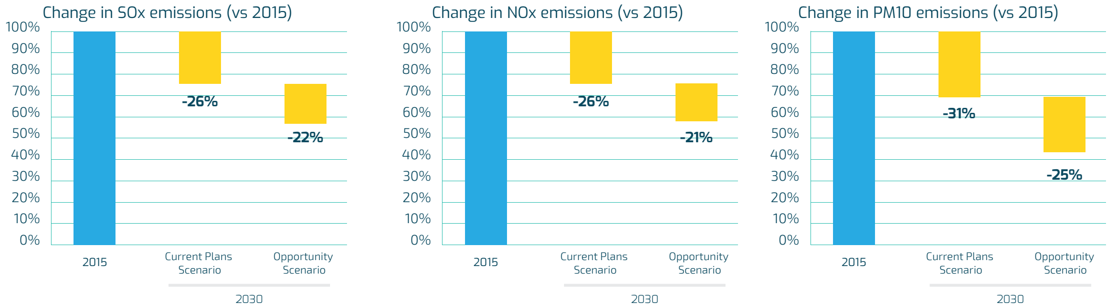


As outlined under Section 1.2.2, not only does the *Opportunity Scenario* deliver the deepest emission reductions and highest job potential, it is also the least polluting in terms of air pollutant emissions with adverse health effects (cf. Figure 26). [29]

Under the *Current Plans Scenario*, Sulphur Oxides (SOx) and Nitrogen Oxides (NOx) emissions are expected to decline by some 26% compared to 2015 levels.[30] The *Opportunity Scenario* further reduces these emissions by 21-22%-points. One third of the emission reductions under the *Opportunity Scenario* is obtained thanks to the reduced utilisation of lignite (16% less production compared to the *Current Plans Scenario*), and two thirds thanks to the lower use of coal (49% less production). Emissions of particulate matter are found to drop by 31% compared to 2015 under the *Current Plans Scenario*, and some further 25%-points under the *Opportunity Scenario*. The slightly higher utilisation of gas power plants in the *Opportunity Scenario* compared to the *Current Plans Scenario* has a negligible impact on these non-CO_2 emissions.

[28] See Annex 2 of the "In-depth overview of the methodological approach and assumptions" document, available online at http://www.energyunionchoices.eu/reports/ for further information about the calculation methodology for labour impacts and applied employment factors.
[29] The emission assessment is restricted to the incineration of fossil fuels. Emissions related to mining, refining or other energy-sector related activities are not taken into account.
[30] See Annex 2 for further information about the calculation methodology and the applied emission factors.

Figure 26: Change in SOx, NOx and PM10 emissions



2. Policy implications

The report presents compelling evidence for faster decarbonisation of the power sector. As described above, the policy portfolio reflected in the *Opportunity Scenario* presents significant opportunities for emissions reductions without increasing costs or lowering energy security standards. Taking advantage of these opportunities, however, requires decisive political and policy action.

First, policy-makers need to complete and fully implement the Clean Energy Package as proposed by the European Commission. This is far from certain: past experience shows major delays and issues with implementing EU energy frameworks.

Beyond the Clean Energy Package, decision-makers will need to take additional steps to pursue smart retirement and smart electrification. These additional levers are essential as neither the EU ETS nor the Clean Energy Package will be tackling the issue of coal generation and overcapacity. Smart electrification policies are critical to provide demand side flexibility which is cheaper and cleaner than flexibility from thermal generation.

This section explores what policy actions should be taken by European and national decision-makers to tap into the opportunities presented by the new energy reality. It can be summarised in five policy actions:

1. **Increase targets for renewables** on EU and national level, reflecting the opportunity for renewable electricity to deliver at least 61% or more of EU-wide net generation by 2030;

2. Develop national plans to advance the **swift retirement of coal generation** assets, including just transition strategies for workers and regions particularly affected;

3. Take forward **deep demand response measures** in retail and wholesale markets to capture the flexibility value of distributed loads coming from electric vehicles and heat pumps. This requires changes in the mandate of TSOs and the way **DSOs** operate;

4. Progressively **deepen regional integration** of energy markets supported by regional governance structures with appropriate decision-making powers;

5. Update the outlook for **critical energy infrastructure needs** in Europe in support of renewed ambition in the electricity sector.

While some of these measures are currently being discussed as part of the Clean Energy Package, other measures are less present on the political agenda, in particular around smart coal retirement and the actions needed to scale up demand side flexibility on a distribution level (actions 2 and 3).

The report, therefore, suggest decision-makers advance all of the above recommendations in parallel.

1. Increase targets for renewable energy

The report shows that, as renewables and flexibility solutions become more affordable, the cost-effective pathway is to increase renewables ambition significantly beyond the levels originally proposed by the European Commission.

The analysis shows renewable shares increase to at least 61% of total net generation across Europe in 2030. This is substantially higher than the 49% renewable electricity projected in the Commission's EUCO30 scenario, reflecting a 27% overall RES target. It also outpaces the 50% of renewable electricity shown in the IRENA RE-map report for Europe, reflecting an overall level of 34% renewable energy[31].

Setting the right level of ambition, therefore, is important to attract the right investments. Targets have proven to be a very effective way to communicate the direction of clean energy policies to the relevant actors. To market players, targets reduce financing risks and provide a perspective on market opportunities, while to policy-makers and regulators targets provide context and orientation for policy decisions and infrastructure planning. Policy makers should expect and anticipate higher delivery by setting higher targets for renewables, both on EU and national level, and planning accordingly.

While this report has not looked at renewables in transport and heating sectors, it is fair to say that **its findings provide compelling evidence in support of RES ambition well above the current Commission target proposals for 2030.** At the same time, as cost for clean technologies are expected to fall further, it must be possible to further increase projections and targets. The target should not be a cap.

2. Accelerated retirement of cheap, depreciated, coal plants

The convergence of new investment in clean energy resources, greater end-use energy efficiency, less energy-intensive economic growth and the legacy of the existing capacity portfolio confronts Europe with the challenge of structural overcapacity. A significant share of this capacity is cheap, depreciated and high-carbon.

However, persistently low ETS allowance prices and the very fact of oversupply mean that markets are not rewarding new investment failing to tap into the potential presented by affordable, clean energy solutions.
A key finding of this report – that echoes findings from other studies – is that phasing out depreciated, high-carbon generation assets is critical to making space for investments in renewable electricity and moving to a cleaner, smarter and cheaper energy system. It also shows that retiring these assets in combination with smart electrification policies results in the deepest emission cuts while reducing overall system costs.

The current EU Acquis on energy and climate is not adequately tackling this matter. The analysis demonstrates that a carbon price of EUR27/tCO_2, as assumed in EUCO30, would not trigger a shift away from coal generation. At the same time, carbon market analysts find this level of carbon price at the high end of what can be expected in 2030 after the recently agreed ETS reforms[32].

At the same time, an additional challenge arises due to the trend in various member states to

[31] Parallel analysis from ECF shows that scaling best practice policies across Europe can deliver much deeper decarbonisation consistent with well below two degrees pathways. See the EU Carbon Transparency Initiative (CTI), an EU deep-dive based on scaling sector-based policies, ClimateWorks, Climact, New Climate.
[32] See footnote 3

circumvent rather than improve the energy market, by adopting out-of-market payments for simple capacity, weakening the energy market's function of rewarding resource investment based on operational capabilities. **The study confirms the importance of avoiding artificially prolonging the life-time of coal capacity through so called capacity payments and mechanisms.** It thus supports putting a carbon-constraint on capacity that can be contracted in national capacity mechanisms, such as the 550 g CO2/kWh threshold proposed by the EU Commission.

It is, therefore, not surprising that debates on a policy-driven retirement of legacy plants have emerged strongly at national level. The state of these debates is picked up in the *Opportunity Scenario* leading to reduced coal fleets in France, UK, Italy, Spain Germany and Poland, and reduced nuclear in France. The findings in this report should give confidence to national governments to advance and fully implement such plans.

Clear and transparent national strategies for a smart and managed retirement of coal plants are now needed. These strategies should include consensually-determined retirement pathways with a cost-efficient decommissioning plan that provide a reliable framework for investors and affected stakeholders. The objective should be to deliver planning certainty consistent with policy objectives and allow for a just and stepwise transition.

The recently agreed ETS reforms ensure that this does not happen in lieu of the EU ETS, but in complementarity to it: Member States will now explicitly be able to withhold a quantity of allowances from auctioning that is commensurate with additional emission reductions from national initiatives, like an accelerated coal phase-out. Furthermore, as of 2023, the amount of allowances kept in the Market Stability Reserve will be limited to the amount of allowances actually auctioned in the preceding calendar year and all allowances beyond this amount will be invalidated. Both measures will not significantly affect ETS price formation in the 2020-2030 decade. However, they do ensure that national initiatives under the EU ETS can have a real effect in reducing emissions.

National initiatives to close coal-fired assets come with socio-economic challenges, particularly if linked to mining activities. Certain jobs will become uncertain; municipalities may lose some of their tax base; pensioners could see retirement funds coming under stress. This is the case irrespective of the report finding significant net positive effects on employment, both in the renewables sector and relative to the conventional sector.

It is of utmost importance that the economic and social consequences of a faster transition are managed through a just transition that involves the local communities and regions that are negatively impacted. Member States that look ahead and provide complementary social policies will likely avoid the most disruptive effects. In addition, there could be a role for the EU in assisting Member States in this effort, for example via **dedicated just transition funds in the EU's new Multi-Annual Financial Framework.**

3. Demand Side Response for "smart electrification"

Demand response, increasingly enabled by new technologies and business models, has huge potential as a flexible resource. As this report shows, it can be cheaper than alternatives and, unlike flexible generation, does not emit carbon making it consistent with decarbonisation objectives.

If anything, the report confirms the importance of getting demand-side flexibility right, especially as exciting electrification trends come with major new loads from electric vehicles and heat pumps on a distribution level.

Integrating these into a smart electrified energy system is probably the most important challenge and opportunity to accelerate decarbonisation at least cost. **It is fair to say, therefore, that smart electrification is the big prize for energy policy-makers.**

The current policy proposals, however, do not exploit this resource in earnest. The Clean Energy Package takes important steps towards removing market barriers and allowing demand side response (DSR) to compete with other sources of flexibility. However, immature markets take time to develop and have barriers to overcome. There is a clear risk that, even if the Clean Energy Package is fully adopted and implemented, DSR may not reach its full potential in time.

Market governance is critical here and is mostly left untouched in the Clean Energy Package. The package does not include any requirement to plan for the level of flexibility that is required, nor does it put obligations on any party to make sure it is delivered. While it is reasonable to expect demand response markets to develop in the next years, the package does not include mechanisms for driving the market creation process at the necessary pace and scale as shown in this report. **It risks leaving behind some of Europe's most innovative new technologies and market players.**

Policy makers should clarify responsibilities and amend mandates of the entities governing the energy market to include:

1. Transmission and Distribution System Operators are explicitly mandated to assess how much flexibility the system will need to cost-effectively deliver EU-wide targets; and
2. National Regulatory Authorities are required to monitor whether DSR markets, including aggregation business, are developing appropriately in line with the pace needed

This involves being clear how the markets for DSR need to develop over time[33], and means that, in case market development is found insufficient, measures should be put in place to help promote the development of this resource, for example by means of obligations on suppliers and system operators

Role of Distribution System Operators

The role of Distribution System Operators (DSOs) is of particular importance. As the outlook for the uptake of local generation, EVs and other new loads connected to local grids looks brighter than currently anticipated, it is critical to be in a position to make the most of these opportunities and utilise local grid infrastructure optimally while minimising investment requirements.

The converse is true as well: if the impacts of these trends are underestimated or sub-optimally managed, they may well inflict significantly higher costs through unnecessary investments for all involved.
Hence, the regulatory framework for DSOs must provide the right economic incentives to ensure the distribution grids do not obstruct this growth. That means:

- DSOs should be incentivized to invest in the optimal mix of network and non-network resources to minimise this cost;
- DSOs should be able to contract for DSR and other services such as storage and efficiency. When contracting for DSR these contracts must not restrict the ability of DSR providers to maximise their earnings by participating in other markets for their services (e.g. "use it or lose it" provisions).

[33] While the European Network of Transmission System Operators for Electricity (ENTSO-E) began on a voluntary basis to project flexibility needs, this is not a yet requirement and certainly does not involve taking a view on how the demand side markets needs to develop.

4. Deepening regional integration of energy markets

Over recent years, some important steps towards the realization of an integrated electricity market have been taken. Europe, however, is far from a fully functioning integrated electricity market. This is most visible on security of supply, which is still largely addressed within national borders[34]. Market coupling has only been partly implemented and interconnector availability to the market remains limited.[35]

This report demonstrates the benefits that the internal electricity market will bring in terms of achieving reliability and integrating renewables at least cost for consumers. It reconfirms the critical importance of some of the provisions in the Clean Energy Package and implementation of the network codes:

- Establishing European and particularly **regional adequacy assessments** that properly assess the contribution of interconnectors to security of supply. A regional approach to security of supply will ensure that resources are being used efficiently across Member States, market interventions remain at a minimum and eventually reliability is achieved at least cost.
- Further enhancing **regional approach to system operation**, in particular by granting the proposed Regional Operational Centres (ROCs) real decision making powers[36], to maximise welfare across all Member States through optimising the availability of interconnectors to the markets, estimating and sharing balancing reserves and coordinated security analysis[37]. For the time being, the EC's proposal should be improved to establish a regional approach to the governance of the ROCs to ensure their fit-for-purpose operation.
- Swiftly implementing **day-ahead market coupling** on the remaining borders, and intra-day and balancing market coupling underpinned by ambitious capacity allocation methodologies. This should ensure that power flows always in the right direction across all timescales.

While it is key that these provisions are not watered-down, more can and should be done. Regional markets and cooperation have been evolving and are expected to continue developing further beyond the Clean Energy Package to achieve a fully integrated market. This is expected to involve additional system operation functions undertaken at the regional level, such as real-time operation of the regional transmission network, coupled with an appropriate regional governance framework.

5. Energy infrastructure priorities for Europe

Cross border electricity infrastructure acts as an important source of system flexibility and enables renewables to be sited in the lowest cost locations. Well-functioning networks underpin the findings in this report.

[34] ACER's Market Monitoring Report (2016), points out that a third of the European Member States assumes no contribution by interconnectors to their security of supply.
[35] Ibid. ACER identified that the capacity offered to the market is less than 50% of the capacity that could have been offered ("benchmark capacity"). In several borders the capacity offered to the market was only residual, less than 30% of the "benchmark capacity".
[36] The EC has proposed decision-making powers for the following functions: (1) coordinated capacity calculation, (2) coordinated security analysis, (3) regional sizing of reserve capacity, and (4) calculating the maximum available capacity of interconnectors for the participation of foreign capacity in capacity mechanisms.
[37] For more information, see: Regulatory Assistance Project and ClientEarth, 2017, Regional Operational Centres: A review of the Commission's proposal and recommendations for improvement, http://www.raponline.org/wp-content/uploads/2017/08/rap_clientearth_regional_operational_centres_recommendations_improvement_2017_august.pdf

However, network infrastructure assets have long economic lives and are slow to develop. Some investments can take 10 or more years between initial concept and commissioning. This means grids need to be planned on the basis of forward looking scenarios, including the Europe-wide Ten-Year Network Development Plans (TYNDP) from the ENTSO-E and ENTSOG.

The pace of change outlined in this report is faster than that foreseen in the ENTSO-E/ENTSOG scenarios. The ENTSOs scenarios are based on 50-58% renewable electricity by 2030; this report suggests it could reach 61% by 2030 with appropriate policies. Similarly, gas generation in the power sector falls faster and further than in any of the ENTSO scenarios.

To make best use of low cost renewables, further additional electricity infrastructure may be needed, for example to tap into the opportunity presented by offshore wind in the Northern Seas, including the Baltic Sea. Offshore wind has seen impressive cost reductions of 50% in the last two years, but cabling and grid connection remain significant cost factors. With a move to more forward-looking and integrated offshore grid planning – as is currently being discussed by the 10 countries of the North Seas Grid initiative – considerable further cost reductions for this important resource will be within reach.

Investment into new renewables generation should not wait until all of the networks are completed however: delays to the TYNDP investments are already factored in to the scenarios used in this report. Instead, new renewable generation and new grid infrastructure should be developed in tandem.

By contrast to the increasing need for electricity infrastructure, the report raises questions over whether further new gas infrastructure investments will be economically viable. The analysis shows that gas consumption in the power sector could drop even deeper than foreseen by the most progressive scenario used by the ENTSOs. In contrast to ENTSO scenarios showing gas demand for power generation remaining broadly stable or only slightly declining to 2030, this analysis suggests gas power generation could decline by half or more, even in the context of smart retirement of coal, lignite and nuclear generation.

These levers require appropriate forward planning. It puts a spotlight on the need for a robust Energy Union Governance Framework and solid and integrative National Energy and Climate Plans. However, it also underlines the need for the National Energy and Climate Plans to be adaptable and robust to swifter technology change presenting new opportunities.

Finally, this report paints a picture of a European energy system undergoing radical rather than incremental changes, driven by deep cost reductions in renewable energy, new business models on the demand side and proactive retirement of baseload coal and nuclear generation. This suggests a new and extensive bottom-up assessment of future EU energy infrastructure needs should be developed, in order to inform the future selection of Projects of Common Interest and financial support under the Connecting Europe Facility.

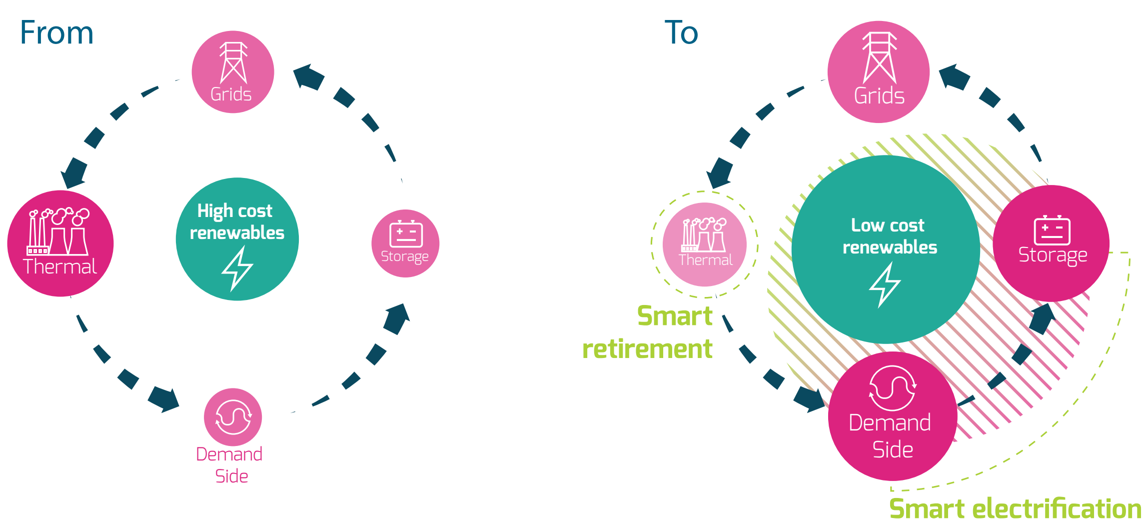
Conclusion

The report paints a compelling picture of the opportunities to accelerate the power sector transition. Delivering deeper emissions cuts at lower cost while restoring energy market prices to scale investments in clean energy solutions should be appealing to any decision-maker at European or national level.

There is, however, a high likelihood that decision-makers involved in climate and energy policy remain reliant on out-of-date understanding of power market economics when deciding on EU and national energy policies.

Central to that is the perception around the need for thermal 'baseload' capacity for supply security. This report shows that a combination of grid infrastructure, demand side flexibility and smart electrification are more than capable of balancing very high shares of renewables, at much lower emissions and at lower cost.

Figure 27: A new way of thinking about power system balancing



The findings of this report provide strong evidence to decision-makers to reap the opportunity of cheaper clean technologies and embrace higher ambition on climate and energy as the most attractive pathway for all Europeans.

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