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Integration of Renewable Energy in Europe

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EXECUTIVE SUMMARY

Integration of renewable generation represents a key pillar of the Commission's broader energy and climate objectives in reducing greenhouse gas emissions, improving the security of energy supply, diversifying energy supplies and improving Europe's industrial competitiveness. In recent years, the Commission and EU electricity industry, including ACER/ERGEG and national regulators, have analysed the feasibility of and potential challenges around power sector decarbonisation and an increasing penetration of the supply of electricity from renewable energy sources (RES-E). Most of this work has been focused on the development to 2020 and the implications of RES-E at transmission level. However, it is widely expected that much of the growth of renewables beyond 2020 may be based on decentralised generation (DG). This may result in additional challenges for distribution networks that are not yet fully understood. Moreover, it is often argued that an increased penetration of decentralised generation will require an active use of demand response (DR) as well as investments into new storage technologies at both transmission and distribution levels.

Against this background, the current study aims at analysing how Europe can decarbonise its electricity sector in the timeframe to 2030, assessing different scenarios with varying level of renewable electricity. More specifically, this study is aimed at enhancing the understanding of how the impacts from alternative future developments on generation, transmission, distribution and storage interact, both locally and across Europe, and what the resulting implications are with regard to the regulatory framework. Compared to existing studies, this study specifically adds value by:

- Using more recent data on technology costs;
- Employing a detailed modelling of each hour of the year, thus capturing the seasonal and daily fluctuations, enabling a valuation of demand response and market value of different conventional and renewable electricity technologies; and
- Focusing on the transmission and distribution grid costs and needs and in particular attempting a quantification of costs related to distribution grid expansion in combination with the impact of distributed generation.

In addition to the quantitative analysis, this study also assesses the risk of insufficient incentives for investments into the necessary infrastructure, including both renewable and conventional generation as well as storage, and analyses possible regulatory reforms in the areas of market design, network regulation and RES-E support schemes, which may help to integrate increasing levels of RES-E.

Some of the key findings of this study are:

a) The analysis in this study has confirmed the findings of the Energy Roadmap 2050 that total system cost 2030 of an electricity system with a high share of renewable electricity in the year may be roughly similar to that of a scenario with less renewable energy (reference scenario). This observation reflects an increasing shift from operational costs for conventional plants (fuel costs) towards capital costs of RES-E, in combination with a continued decrease of specific investment costs for RES-E.

b) The cost-efficient integration of a high share of RES-E will require significant infrastructure to be built, including transmission and distribution networks as well as conventional backup generation.

c) Compared to the use of more centralised sources of RES-E, which are directly connected to the transmission grid, an increasing penetration of distributed generation will also require an extension of European distribution networks. However, the need for distribution expansion strongly depends on the type and penetration of DG, and different measures can be taken to minimise the need for distribution expansion.

d) Among the various options to achieve a cost-efficient integration of a high share of RES-E, demand response stands out as particularly promising. The analysis in this study suggests that an effective use of DR may yield annual savings in the order of € 60 to 100 bn[1].

e) The need for grid expansion and conventional back up capacity can furthermore be reduced by a balanced geographical distribution of renewable energy production, taking into account not only resource availability but also proximity to load. In line with decreasing costs of renewable electricity, the cost of grid expansion increasingly becomes a relevant factor, which may offset higher generation costs of RES-E that are deployed at less optimal geographical locations.

Key Scenarios

Focusing on RES-E expansion between 2020 and 2030, three main scenarios were considered in the model analysis, based directly on scenarios from the EU Energy Roadmap 2050:

- An 'Optimistic Scenario' (corresponding to the 'High RES-E' scenario), characterised by a fast expansion of RES-E based generation;
- A 'Middle Scenario' (corresponding to the 'Diversified Supply Technology' scenario); and
- A 'Pessimistic Scenario' (corresponding to the 'Current Policy Initiatives' scenario) with a low RES-E expansion trajectory.

The necessary assumptions concerning regional and technological developments were taken from the PRIMES based simulations underlying the Energy Roadmap 2050. In contrast, assumptions on the costs of different technologies were updated, in order to reflect developments in recent years, such as a major reduction in the costs of solar PV or higher than expected costs of offshore wind power.

In order to investigate the impacts of RES-E on systems with different levels of energy consumption, two additional scenarios were considered as variations of scenario 1.

- Sensitivity 1a: Optimistic scenario with high demand
  Based on the consumption in the 'Reference Scenario' of the Energy Roadmap 2050, but with the same share of RES-E as in the High RES-E scenario; and
- Sensitivity 1b: Optimistic scenario with high energy efficiency
  Based on the consumption in the 'High Energy Efficiency' scenario of the Energy Roadmap 2050, but with the same share of RES-E as in the High RES-E scenario.

Figure 1 illustrates the levels of RES-E production and annual electricity demand in all main scenarios in comparison to other studies investigated by Greenpeace, Eurelectric, EWI/Energynautics and the European Climate Foundation (ECF).

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[1] This figure does not include the costs of deploying demand response, which was not possible to estimate within the context of this report.

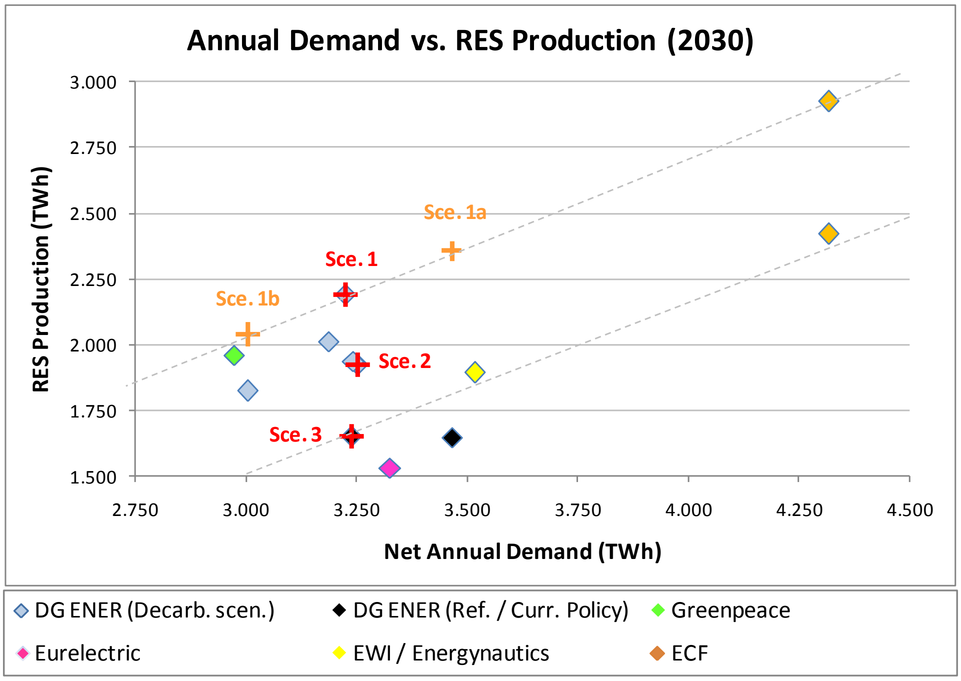

Figure 1 Overview of Main Scenarios and Variations of Scenario 1

In order to assess the impacts that DG brings to the system, we have considered three additional scenarios with an increased share of DG, in particular solar power, that are based on the variations of Scenario 1. These additional variations are subsequently denoted as Scenarios 1-DG, 1a-DG and 1b-DG. Table 1 provides a summary of all main scenarios and variations, which we have analysed in this study.

Table 1 Overview of Main Scenarios and Basic Sensitivity Studies

#	Scenario / Variation	Description	Share of RES	Additional Variation
1	Optimistic Scenario	RM 2050 'High RES-E'		
1a	Optimistic scenario with high demand	Demand: RM 2050 'Reference'; RES-E: Same share as scenario 1; Nuclear: RM 2050 'Energy Efficiency'	68%	High share of decentralised generation (DG)
1b	Optimistic scenario with high energy efficiency	Demand: RM 2050 'Energy Efficiency'; RES-E: Same share as scenario 1; Nuclear: RM 2050 'Reference'		
2	Middle Scenario	RM 2050 'Diversified supply technologies'	59%	-
3	Pessimistic Scenario	RM 2050 'Current policy initiatives'	51%	-

Additionally, a range of sensitivities were analysed to gain more detailed understanding on specific topics. These include a sensitivity with "Load-Driven" expansion of variable RES-E that is based on scenario 1-DG: instead of placing RES-E in regions with the most favourable conditions but remote from load centres, a more "balanced" distribution was considered by shifting between 40 TWh and 100 TWh of production from variable RES-E, notably from offshore wind power, to local biomass and solar power. In addition, we assume a further shift of onshore wind and solar power from coastal regions in North-Western Europe and the Iberian Peninsula to inland locations, i.e. mainly in Central Eastern and South-Eastern Europe.

Table 2 compares the assumptions on production and installed capacity by RES-E technology for the original Scenario 1, the variation with an increased penetration of DG (1-DG) and the load-driven scenario.

Table 2 Summary of Assumptions on Scenarios 1, 1-DG and 1 – LD

Technology	Production (TWh)			Capacity (GW)		
	Scenario			Scenario		
	1	1-DG	Load-driven	1	1-DG	Load-driven
Hydropower	375	375	375	120	120	120
Biomass	333	333	395	78	78	84
Wind (onshore)	674	674	726	309	309	338
Wind (offshore)	524	307	193	160	94	61
Solar	256	473	473	195	361	361
Other	31	31	31	5	5	5
Total RES-E	2,193	2,193	2,193	867	967	969

The impact of delayed and, indeed, no transmission expansion were also considered. Previous experience would indicate that transmission reinforcements may be difficult to deliver due to growing public opposition. Thus, in order to investigate the impact of this scenario on the integration of RES, we have considered delayed transmission expansion – where incremental transmission capacity is reduced compared to the outcome of the original scenario, i.e. by 50% for all incremental capacity up to 5,000[2] MW and 66% (i.e. 2/3) for all incremental capacity in excess of 5,000 MW. Please note that these restrictions only apply to onshore connections, whilst there are no constraints applied to the expansion of offshore connection. The sensitive nature here is also being considered for Scenarios 1 and 1-DG. Furthermore, No transmission expansion post 2020 – where we do not allow for any expansion of transmission network after 2020.

Furthermore, we analysed a sensitivity looking at the potential impact of demand response. This sensitivity is based on scenario 1 and the ability to shift up to 7.5% of daily peak load and 5% of daily consumption.

Finally, we considered the impact of an increased use of heat pumps (HP) and electric vehicles (EV), which are often seen as an important instrument for increasing energy efficiency and reducing CO_2 emissions, in an additional sensitivity. This sensitivity assumes an incremental demand of approx. 250 TWh, which is split 60:40 between HPs and EVs. As a consequence, this sensitivity is basically comparable with Scenario 1a - DG[3], but with a different hourly load profile.

Modelling Framework

In this section we describe the models used for assessing the operational and investment implications of integration of RES, considering generation, transmission and distribution sectors of the system including modelling of market signals relevant for investment in different technologies.

2 This limit is selected to reduce extreme outcomes. In addition, it also reflects the assumption that larger projects are more likely to face technical barriers and/or opposition. At the same time, the proposed method has the advantage that it is not necessary to take decisions on individual interconnectors, which would necessarily remain arbitrary.

3 Since HPs and EVs both contribute to decentralized demand, it seems useful to combine them with an increased use of DG.

Generation and Transmission Modelling

Two models have been applied for determining the optimal generation and transmission infrastructure and simulating the market outcome for each of the scenarios:

1. Firstly, we determine the optimal expansion of conventional power plants in a commonly used tool for generation and market modelling. Five different generation technologies can be endogenously built by the capacity expansion model. They include coal-fired steam turbines, with or without Carbon Capture and Storage (CCS); Combined-Cycle Gas Turbines (CCGT), with or without CCS; and Open-Cycle Gas Turbines (OCGT) as peaking/back up capacity. The model optimises the generation expansion path for the period 2020 to 2030, with a further forecast up until 2050. This model automatically closes down existing plants at the end of their technical lifetime[4] and adds new generation capacity such that the overall generation costs are minimised. For this purpose, the capacity expansion module considers the initial investment cost and ongoing fixed cost, as well as the expected variable operating costs, i.e. mainly for fuel and carbon emissions. Consequently, new capacity of a given type is built only if it represents the least-cost solution over the entire time horizon of the study.

2. The second model, i.e Dynamic System Investment Model (DSIM) developed by Imperial College London, is used to determine the need for transmission and back up generation based on simulation on the operation of the spot markets. More specifically, this model seeks to minimise the total system costs including (a) annual electricity production cost (b) transmission network reinforcement costs and (b) additional generating capacity to meet system reliability requirement. The model also optimises the sharing of generation capacity reserves across the system through transmission links, so that reliability requirements can be met at minimum costs through making full use of interconnectors. The integrated reliability assessment calculates the loss of load expectation (LOLE) by assessing whether adequate generation will be available for each hour of the year to meet the demand[5]. 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, and the probable contribution from renewable generation and the associated short and long-term correlations with demand.
   The generation and transmission model principally covers the entire European market and considers the chronological production of variable RES-E and demand on an hourly basis for a full year. As such, the model captures both the influence of variable production from wind and solar power on generation dispatch and the need for reserve and back up capacity as well as including positive regional integration effects, i.e., the relative variability of wind and solar decreases when aggregated over a larger area.

For the modelling of the transmission grids, we have developed a simplified grid model that is based on a zonal transport model with a total of 74 individual nodes and approx. 165 existing and potential (inter-) connections between these nodes. As illustrated by Figure 2 this grid model covers all Member States that are physically part of the interconnected electricity market within the EU[6]. By also including Norway, Switzerland, Albania and the remaining members of ENTSO-E in South-Eastern Europe, the model provides for a comprehensive coverage of the continental European grid.

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4 Or potentially before, in case capacity is no longer needed

5 The economic trade-off is made by assessing the annualised costs of new transmission and back up generation capacity against the loss of load (with an assumed cost of €50,000 per MWh), and subject to a maximum LOLE of less than 4 hours per year.

6 Including Croatia but excluding Cyprus and Malta

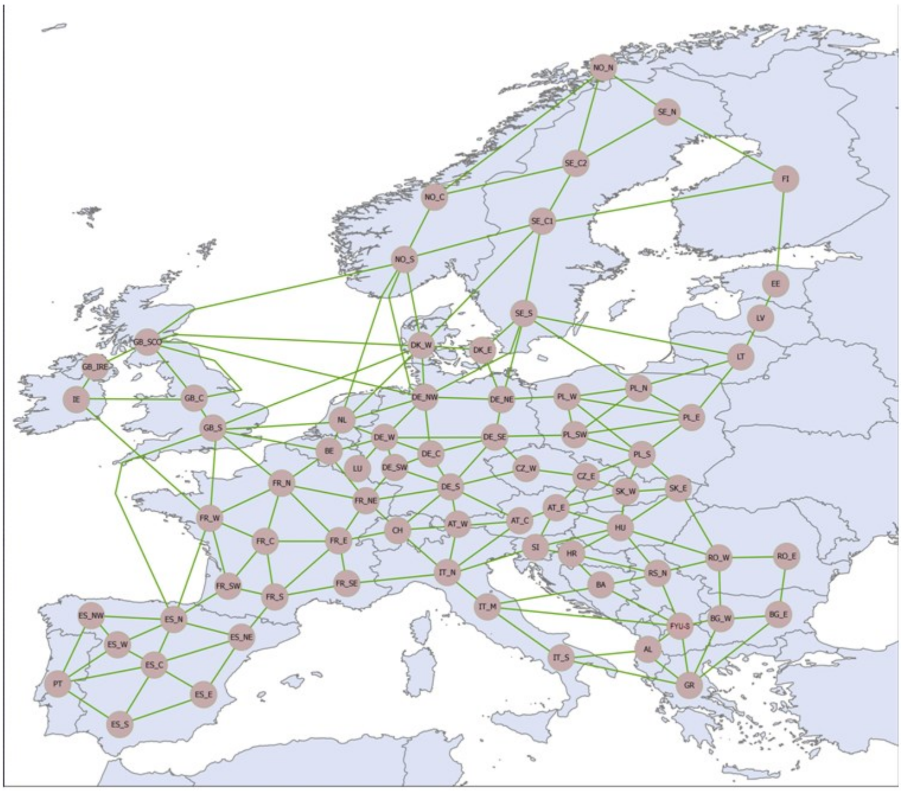

Figure 2 Topology of Regional Transmission Model

In many cases, the networks of individual Member States are represented by two or more network zones, in order to better reflect internal congestion and the potential need for transmission expansion especially within larger countries[7].

Similar to the approach chosen by ENTSO-E for the 10-Year Network Development Plan, the capacity of each existing (inter-) connection is determined by the Grid Transfer Capability (GTC). The GTC specifies the ability of the grid to transport electricity across a given boundary, i. e. from one area (one particular country or an area within a country) to another. The use of GTCs effectively corresponds to the notion of transfer capacities, which are commonly used for determining the transmission capacity available for cross-border trading in the European electricity markets. The corresponding values have been derived from the NTC[8] values published by the European TSOs, the incremental GTC's specified in the latest version of the 10-Year Network Development Plan (from July 2012) and from our own analysis of the existing and planned transmission infrastructure. Besides the GTC of current and planned infrastructure, each (inter-) connection is characterised by the specific costs of capacity expansion, in terms of €/MW/km. The corresponding values are based on typical values, which have also been used as part of various other studies and which reflect the fundamental difference between AC and DC lines, as well as topography.

7 In contrast, we have partially aggregated the countries in the Southern part of former Yugoslavia, due to the small size of the corresponding power systems and a limited expected impact on the development of the transmission grids at the European level.

8 Net Transfer Capacity

Market Modelling

The integrated market model in DSIM produces a range of time and locational specific market prices including prices based on wholesale electricity marginal fuel costs, scarcity prices, and prices for frequency response/fast reserves, spinning and standing reserves. These prices should provide time and location specific market signals for operation and investment in generation and storage with appropriate levels of flexibility as well as investment in interconnection. We note that the model is deterministic, resembling a market with perfect competition and information. Hence it does not consider market nor operational uncertainty, for instance uncertainty on generation availability, demand, etc.

Distribution Network Modelling

The primary objective of the distribution analysis is to estimate the need and cost for distribution expansion in different future development scenarios. This analysis also reveals whether and to what extent the use of distributed generation can facilitate avoiding distribution network reinforcement costs. In order to enable such analysis, we applied the Dynamic Distribution Investment Model (DDIM) developed by Imperial College London. DDIM tests whether thermal, voltage and/or fault level constraints are violated and proposes appropriate upgrades of assets. The model can be used to analyse alternative network reinforcement and design strategies, and to quantify the potential benefits of alternative mitigation measures such as demand response and other active network management techniques.

In order to enable an analysis on a national basis, the model uses a set of typical networks called Generic Distribution Systems (GDS), which are developed based on the collected information on population density, typical network design policies and standards in different Member States (an example is presented in Figure 3). The models capture various distribution voltage levels, network topologies and load densities (rural, suburban, urban), distribution of DG, various load characteristics of different consumers (domestic, commercial, industrial) and specific devices such as heat pumps and electric vehicles. When applied to different Member States, network voltage levels are adjusted to represent distribution networks typical for individual countries.

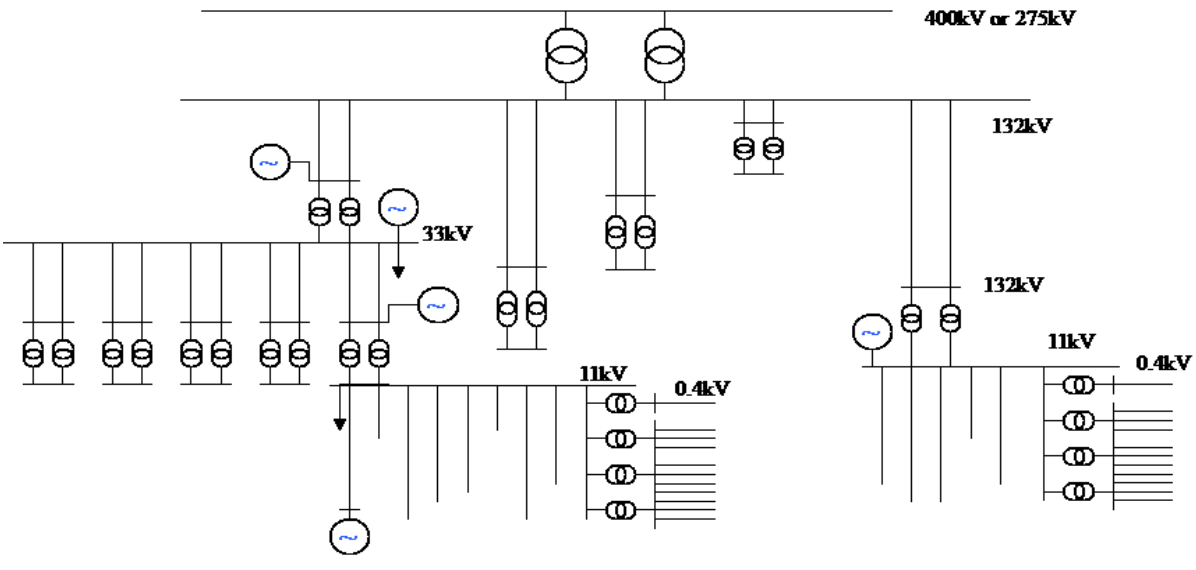

Figure 3 Example of Schematic Network Diagram of GDS

The GDS platform uses the concept of characteristic days in order to perform annual analysis: typical daily profiles of weekdays, Saturdays and Sundays for winter, summer, and autumn/spring seasons are used. Based on these inputs, the GDS model performs an annual analysis through AC power flow and optimal power flow calculation. Results of the analysis are detailed information of many aspects of the network including losses, power flows, voltage profile and fault levels.

Future Costs and Infrastructure Requirements for Integration of RES-E

Impact of RES-E on Incremental Costs of Electricity Supply

Figure 4 provides an overview of the (annualised) investment and generation operating cost for the main and basic sensitivity scenarios. The overall development and the resulting cost levels are roughly similar across the three main scenarios in 2030, despite a different penetration of RES-E. These calculations are based on the updated assumptions on the costs of different RES-E technologies, which have been used for this study. Conversely, when using the original assumptions of the Energy Roadmap 2050, incremental system costs would be some € 13 bn higher on an annual basis. Similarly, the technology assumptions from the recent 2030 Impact Assessment (2013 Reference scenario) lead to an increase of annual costs by some € 35 bn in 2030.

In line with an increasing share of renewable energies, all scenarios require major investments into RES-E capacity. By 2030, investments into RES-E and OPEX of conventional generation together account for approximately 75% of total incremental costs of electricity supply. At the same time, these developments require significant investments into additional infrastructure, i.e. transmission and distribution and networks, as well as new conventional generation. Even when excluding the costs of RES-E and traditional conventional plants (e.g. coal plants and CCGTs), this may lead to incremental costs of between € 20bn and € 50bn annually in 2030.

On the basis of annualised costs, distribution expansion accounts for the majority of the corresponding investment costs (approx. 60% to 70%), followed by investments into back up generation, whereas transmission represents less than 15% to 20% of total investment costs in all scenarios. Investment and operating costs calculated for all basic scenarios and the relevant sensitivity scenarios are summarised and presented in Figure 4.

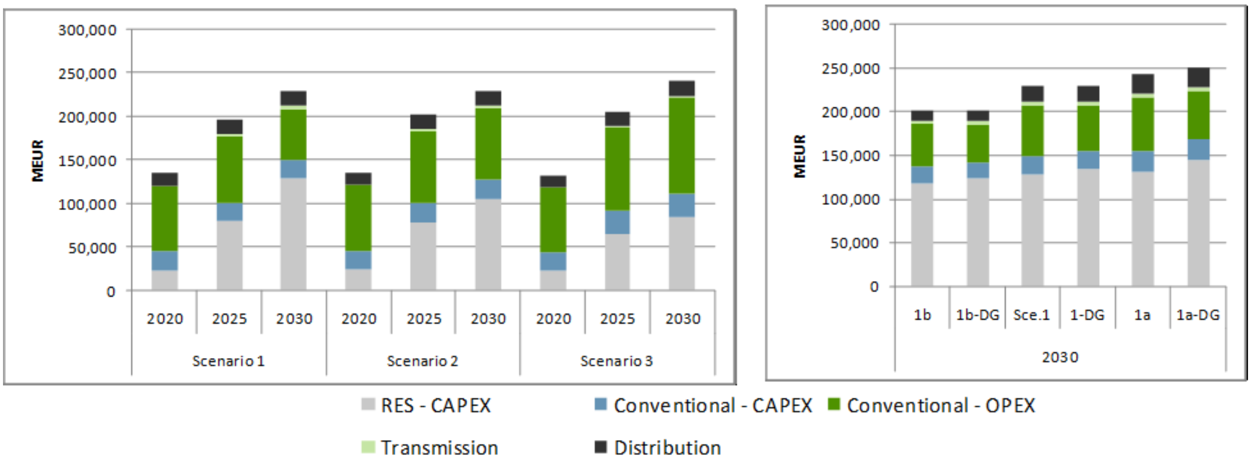

Figure 4 Overview of incremental costs of electricity supply in the main and basic sensitivity scenarios

These numbers show how important it is that one understands the main drivers for infrastructure needs, relevant technical barriers as well as possible technical mitigation measures that may help reducing infrastructure requirements. In the following, we briefly identify and explain the main drivers for infrastructure needs in each of the three different areas, followed by a brief summary of relevant technical barriers.

Impact of RES-E Deployment on Conventional Generation

The study has demonstrated that different scenarios may require a different volume and structure of conventional generation capacity. The need for conventional generation capacity is primarily driven by the evolution of electricity demand, whereas the choice of different variable RES-E technologies appears to be of secondary importance. Based on the findings, the study leads to the following conclusions with regards to the ability of RES-E to displace conventional generation and the residual requirement for conventional generators:[9]

- An increasing penetration of RES-E can displace the output of conventional generation capacity. This effect is primarily driven by capacity factors of RES-E but is not directly related to the technology or source of renewable energy.
- Conversely, the impact of RES-E on the total need for conventional plants, and other types of firm capacity, strongly depends on the type of RES-E. Whilst controllable sources, such as biomass, geothermal energy or hydropower, effectively contribute to generation adequacy, the contribution of variable RES-E to security of supply remains limited.
- Even in combination with a large-scale expansion of European transmission grids that improves the diversity of the output profiles of RES-E and reduces volatility, the capacity value of RES-E is still limited due to possible coincident events of low RES-E output across Europe and peak demand[10]. The effect of this is demonstrated in every scenario; for example in scenario 1 (Figure 57) the amount of conventional capacity remains broadly similar in 2025 and 2030, although the installed capacity of renewables increases significantly.

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9 Unless specified otherwise, all conclusions apply for both centralised and decentralised RES-E, but note that no demand response has been included in the basic scenarios.

10 The firmness of different RES-E technologies is not linked to their capacity factor, i.e. even variable RES-E generators with a high capacity factor may not be able to substantially contribute to firm capacity

- As the capacity of conventional plant is reduced at lower rate than the reduction in their energy output, this reduces the load factor of plant and may affect the economic feasibility of the plant operation.
- The geographical distribution of RES-E represents an important driver for infrastructure needs. Renewable generation that is located close to demand centres may allow reducing demand for new network capacity in comparison to the capacity needed if RES-E is installed at remote locations.

Scenario 1	2020	2025	2030
Nuclear	125	107	91
Coal conv.	119	69	44
Gas conv.	155	138	92
Oil	33	11	6
Back up	63	89	157
Hydro	115	117	120
Biomass	61	70	78
Wind (on)	186	223	313
Wind (off)	64	92	157
Solar	54	88	188
Other RES-E	2	2	5
Total	976	1,008	1,250

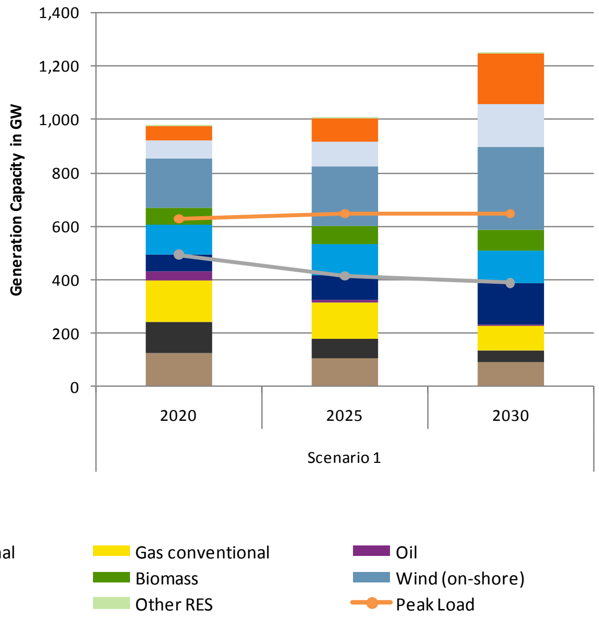

Figure 5 Generation Capacity in Scenario 1 (2020 - 2030)

Transmission Expansion

The study also shows how different scenarios and assumptions will lead to different levels of transmission network expansion and reinforcement, which is required to facilitate least-cost integration of (variable) RES-E. Reduced levels of transmission may result in increased curtailment of RES-E generation.

Overall, we make several key observations from the analysis conducted:

- Transmission expansion becomes increasingly important as the penetration of RES-E grows. This is illustrated in Figure 6 whereby it shows the increased demand for transmission capacities across Europe in order to accommodate the growth of RES-E. As shown in this figure, the demand for capacity is higher in the scenarios with higher RES and it is increasing over the periods between 2020 and 2030.

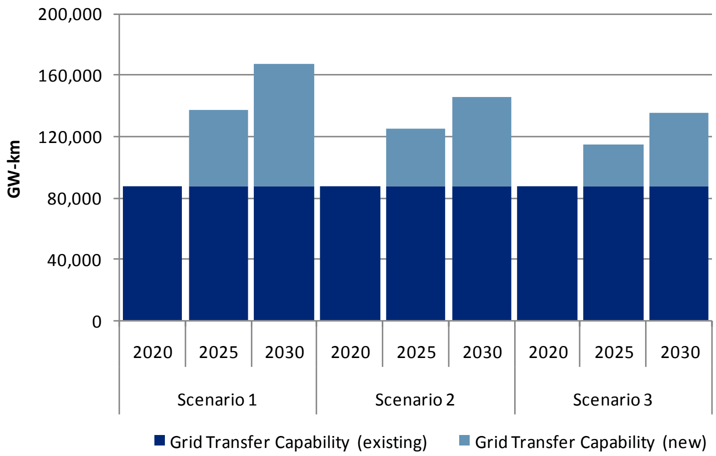

Figure 6 Development of Grid Transfer Capability in the Main Scenarios (2020 to 2030)

- As a major share of RES-E are located at quite a distance from demand centres in the main scenarios, significant additional capacities are needed. If the demand for new capacity is large (tens or more GW) this challenges the current technologies as power density across single transmission corridor should be improved to limit the number of transmission corridors needed. The scale of transfer capacity across European main transmission system needed to accommodate scenario 1 is illustrated in Figure 7.

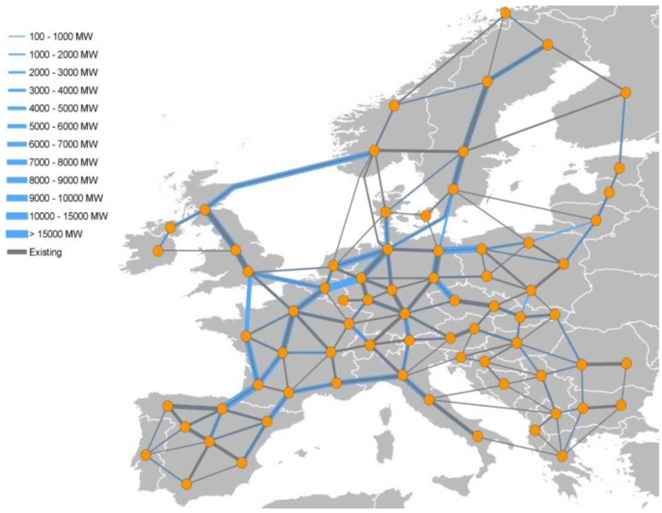

Figure 7 Existing and Final Transmission Capacity in Scenario 1 (2030)

- Transmission investments are mainly driven by differences in the costs of available electricity (energy) at different locations. With regard to RES-E, this implies that the need and benefits of transmission are primarily driven by the geographical distribution of RES-E and load as indicated by the load-driven scenario in Figure 8. A balanced geographical distribution of RES-E across Europe, or within individual countries, thus provides for an effective instrument for facilitating the integration of both controllable and variable RES-E. This means that the benefits installing RES-E at resourceful locations (with higher capacity factors) should be balanced with the cost of infrastructure needed.

Similarly, the cost of transmission reinforcement can be balanced against cost of renewable generation curtailment.

- In addition to the main function of facilitating exchange of energy between different regions, transmission may also support the sharing of flexibility and security of supply between neighbouring areas. It can thus help to reduce the total amount of firm conventional capacity in the system. This is demonstrated in Figure 8 which shows the increased back-up capacity in the scenarios where there is further transmission development beyond 2020, or if the development were to be delayed[11].
- The need for and benefits of transmission expansion are also influenced by other measures, which may be taken with a view to facilitating the integration of variable RES-E. As an example, Figure 8 shows that the need for back up capacity can also be reduced by demand response.

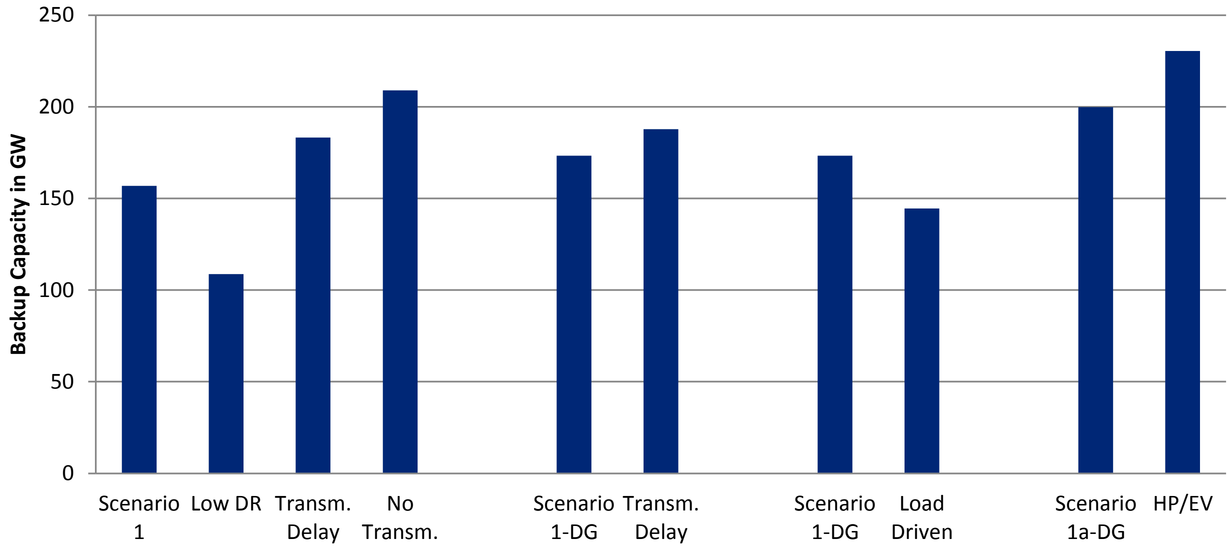

Figure 8 Back up Capacity in the Sensitivities of Scenario 1 (2030)

Distribution Expansion

As mentioned above, distribution accounts by far for the largest share of additional infrastructure that is required to facilitate the integration of decentralised RES-E. Although distribution expansion is partially influenced by the same factors as transmission reinforcements, it is important to account for some specific drivers, such as the growth and flexibility of demand, or the variability and connection voltage level of decentralised RES-E.

Figure 9 shows the cumulative cost of distribution reinforcements in the main scenarios. In 2020, cumulative costs reach around € 170 bn in all three scenarios. Between 2020 and 2025, costs increase to some € 215 bn but then remain fairly stable thereafter. Moreover, it is interesting to note that the three main scenarios lead to very similar cost levels. For instance, the cumulative costs of Scenario 1 exceed those of Scenario 3 by less than € 10 bn, which is less than 5% of the total. Figure 9 also shows a common pattern regarding the distribution of costs between voltage levels. For the main scenarios, reinforcement cost in LV networks range from € 65bn to just above € 82bn, or roughly 40% of total costs. Conversely, the relative shares of reinforcements at the MV and HV levels may vary more

11 This is similar to the findings of another recent study on behalf of DG ENER (Booz&Co, Benefits of an Integrated European Energy Market, a report prepared for Directorate-General Energy European Commission, July 2013), which found that implementing such policies can reduce the peaking capacity across Europe by around 100 GW.

substantially, with less investments at the HV level especially for lower shares of DG. On average, reinforcements at the HV level account for about one third of total cost, and MV networks for approx. one quarter.

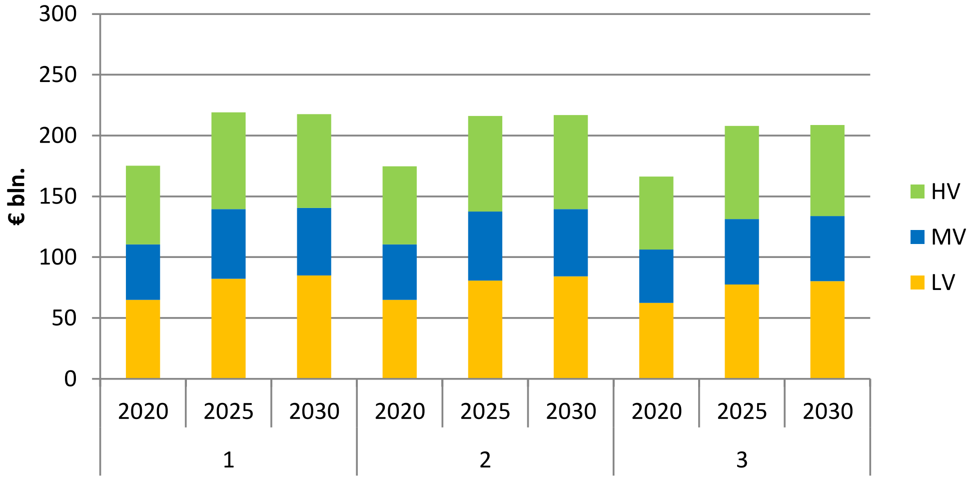

Figure 9 Cumulative distribution reinforcement costs in the main scenarios (EU-28, EUR bn)

The main drivers for the need of distribution expansion can be summarised as follows:

- In the scenarios used for this study, which are based on the Energy Roadmap 2050, the future need for distribution reinforcements seem to be substantially driven by load growth. This is clearly demonstrated in Figure 10 where network reinforcements in scenario 1b (with high energy efficiency) are much less than in the basic scenario 1. Similarly, distribution network costs in scenario 1a (with higher load) are higher than in scenario 1.

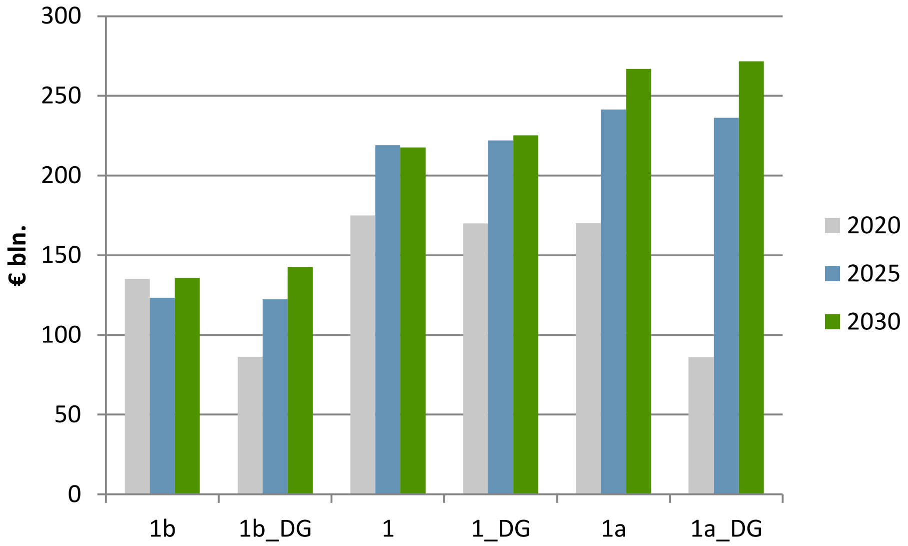

Figure 10 Estimated cumulative cost of distribution expansion in the variations of Scenario 1 (EU-28, EUR bn)

- An increasing penetration of variable DG represents a second driver for distribution network reinforcement. Whilst our studies do not show a significant impact of the level of DG penetration on the total costs of distribution by 2030, we have observed that costs increase in some networks with a high penetration of variable DG. This is for instance as illustrated in Figure 11, which shows that a high penetration of variable DG, i.e. solar PV, requires a substantial expansion of distribution networks in Germany, in order to deal with increasing reverse flows and / or voltage problems.

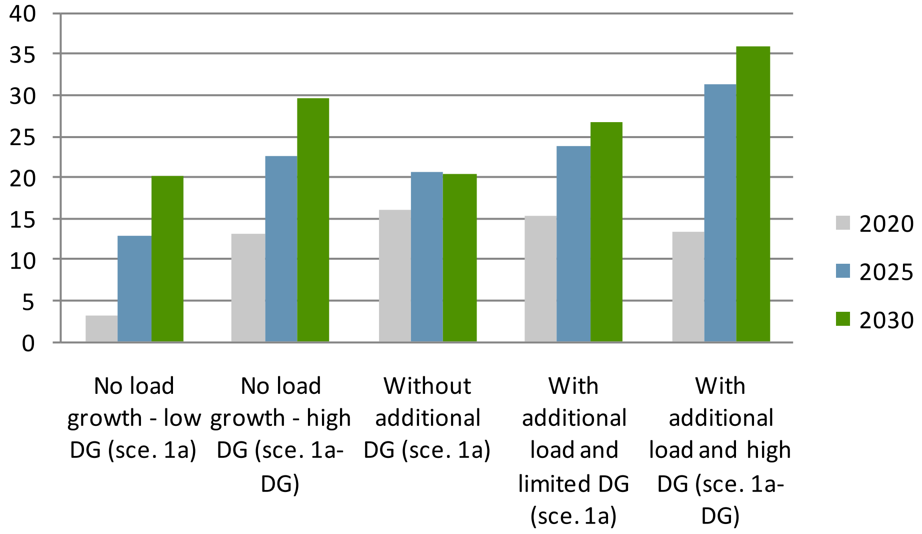

Figure 11 Impact of DG-RES and Load Growth On Cumulative Distribution Reinforcement Costs in Germany (EU-28, in EUR bn)

- DG-related distribution expansion is mainly driven by the type of RES-E. Controllable DG, which accounts for a considerable share of total DG in the DG scenarios, is less likely to require network reinforcements, or may even allow avoidance or deferring network reinforcement. Conversely, distribution network expansion will generally be required to facilitate integration of higher penetrations of variable RES-E. Similarly, the need for distribution expansion strongly depends on the production profile of variable RES-E and its correlation with local load profiles.
- In contrast to the transmission level or MV/HV distribution network, a substantial share (more than 50%) of necessary LV distribution network reinforcements is caused by voltage problems. This can be demonstrated by comparing figures for the main scenarios in Figure 12 with the relevant components in Figure 10.
- Since distribution networks are still currently operated in passive mode, the applications of smart grid technologies (such as in-line voltage regulators) could reduce the integration cost of DG-RES-E substantially, by enhancing the utilisation of assets and providing active voltage control in distribution networks.

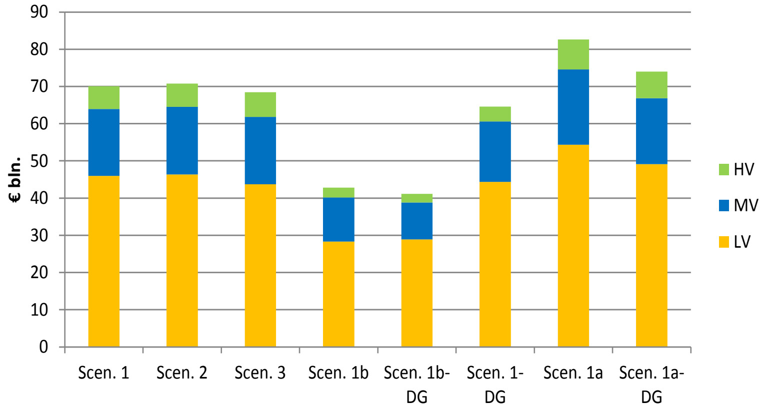

Figure 12 Cumulative voltage driven reinforcement cost by network voltage level for the main scenarios and the variations of Scenario 1 in 2030 (EU-28, in EUR bn)

Centralised vs Decentralised RES-E

Figure 13 shows that the costs of integrating high shares of DG-RES are generally higher than those in 'centralised' scenarios. These results are particularly driven by the scenarios where a significant amount (circa 70 GW) of large offshore wind in scenario 1 is converted into distributed PV (solar) in scenario 1-DG. Considering that the capacity value of PV in supplying the typical winter evening peak load in most Europe is practically nil, this leads to the increase in back-up capacity.

In these cases, this increase in the demand for firm generation capacity may offset the savings, if any, that DG brings into distribution networks. It is also worth noting that there is no significant impact on the transmission requirements and this is due to the approach taken in developing the main scenarios and variations, i.e. the DG substituting the centralised generation is placed at the same regions and it is therefore expected that the impact on transmission is modest. The results are summarised in Figure 13.

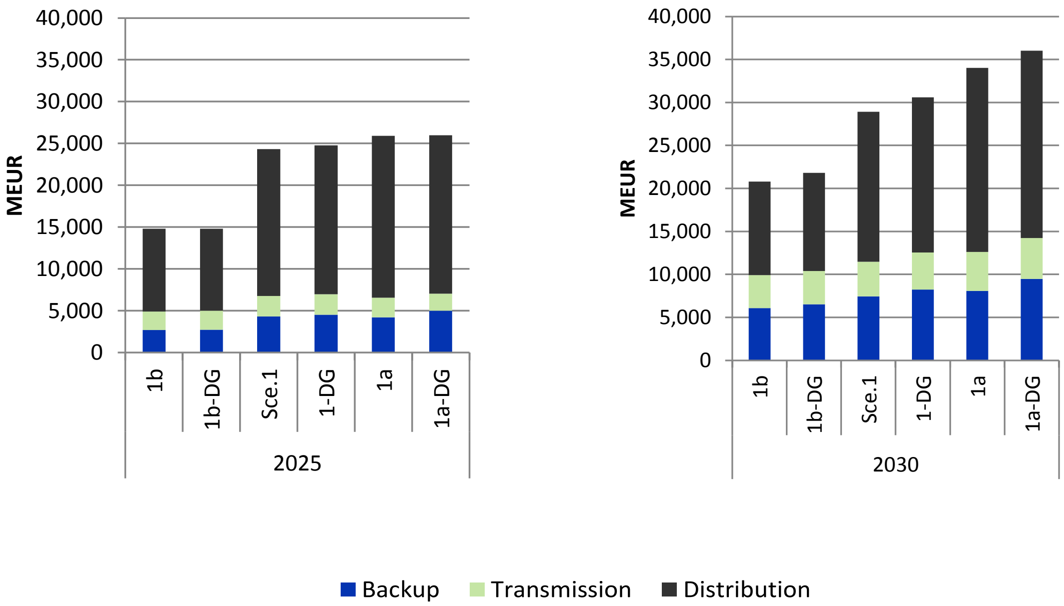

Figure 13 Summary of Annualised Investment Costs for the Variations of Scenario 1

Since the impacts are not very significant and this depends on the selection of DG-RES used to substitute the centralised RES, our studies do not show any clear advantage for either centralised or decentralised generation. But the results of our analysis also provide several important insights into the role and of DG on infrastructure requirements and the costs of electricity supply. In particular, the analysis in this study has shown that:

- The choice between decentralised and centralised generation in a given region does not have any direct impact on the need for transmission and back up capacity;
- DG may both cause and avoid distribution expansion, depending on:
  - Type of DG (i.e. controllable resources vs. variable RES-E and correlation with load);
  - Penetration of DG;
  - Vertical distribution (i.e. connection level);
  - Horizontal distribution (proximity to load and transformer stations);
- Need for distribution expansion can be strongly reduced when combined with more flexible demand or decentralised storage.

The simulations carried out in this study show that the costs of transmission may both increase or decrease when increasing the share of DG. But as mentioned above these impacts are mainly driven by the type and regional distribution of variable RES-E on a European level rather than the choice between centralised and decentralised generation within a given region. The same applies to the need for back up capacity, which generally increases in the DG scenarios in this study. These observations highlight the importance of carefully differentiating between the choice of different RES technologies, their deployment across different regions, and between centralised and decentralised installations.

In contrast, the analysis in this study clearly shows that DG has a significant impact on the need, composition and costs of distribution expansion. DG may both cause and avoid distribution expansion, depending on the type of DG. Whilst controllable resources may avoid or at least defer distribution expansion, the possible savings from variable DG remain highly limited as they cannot guarantee a firm supply of electricity at times of peak load. Quite in contrast, additional distribution capacity is required to integrate higher levels of variable DG, mainly due to the limited capacity factor of variable RES-E (e.g. solar PV). Although the need for distribution expansion is also influenced by the correlation between production profile and load profiles, network expansion is mainly driven by the maximum amount of capacity that is fed back to the grid.

Besides the type and overall penetration of DG, the need for distribution expansion also depends on the vertical and horizontal distribution of DG. Connecting DG to higher voltage levels allow accommodating a higher absolute penetration of DG but will reduce the benefits of avoided or deferred network expansion, especially in case of controllable DG. In addition, the need for distribution expansion is influenced by the horizontal distribution of DG, i.e. its proximity to load and transformer stations. Hence, the need for distribution expansion can be reduced by installing production capacities closer to demand (e.g. in urban or suburban rather than rural areas), or by locating (variable) DG closer to the transformer at the start of individual feeders.

These considerations indicate that the impact of DG depends on a multitude of different factors and the local situation. There is no universal relation between the share of DG and the need of distribution expansion. Similar developments may thus lead to different outcomes under different circumstances.

Technical Barriers and Mitigation Measures for Integration of RES-E

The analysis carried out demonstrates that insufficient network infrastructure represents an important barrier for efficient utilisation of available production from variable RES-E. A lack of transmission or distribution capacity leads to increasing levels of curtailment and may, in the case of insufficient transmission capacity, require also additional back up capacity to be built. Furthermore, the capability of the power system to integrate additional RES-E may also be constrained by insufficient flexible generation or demand (although the corresponding effects have not been all quantitatively assessed in this particular study).

Apart from these fundamental developments, connection conditions may represent another technical barrier for the integration of RES-E. Apart from requirements on generation technologies, this especially applies to the technical rules governing the point of connection. Allowing variable RES-E to connect to any point in the network without consideration of local conditions may result in an excessive need for network reinforcements and hence lead to substantial additional costs. Conversely, any undue restrictions may create substantial economic barriers for on DG-RES and it is therefore important to consider mitigation measures both through the use of cost effective technical solutions and appropriate regulatory measures.

We have analysed a number of technical measures and solutions, which may be considered in order to facilitate the integration of RES-E whilst limiting the need for additional infrastructure and reducing overall costs to consumers. Among others, we have identified that demand response potentially is one of the most promising low cost instruments that provides alternative source of flexibility and brings substantial benefits in the integration of RES-E. DR generally allows for a short-term redistribution of electricity demand. Any decrease or increase in consumption will usually be compensated within several hours. In a way, DR is thus similar to energy storage, but with potentially much higher round-cycle efficiency (close to 100% in many cases). In practice, DR offers different functionalities: i.e. peak-load reduction, load-shift to improve the ability of system to absorb RES-E output and to provide ancillary services, e.g. as standing reserves. DR can be provided by electricity systems that have some forms of storage or operational flexibility, for example: EV, HVAC, smart appliances, etc.

To illustrate the potential benefits of DR, Figure 14 summarises its impact on annual costs of incremental investments and generation OPEX. Whilst this figure does not show the costs of DR, this figure indicates that the net benefits of demand response will remain positive at least for those types of DR that can be used and activated at limited costs. DR can contribute to the reduction in back-up capacity, reduction in transmission and distribution network cost, and reduction in operating cost for example by improving the utilisation factor of RES-E output and therefore reducing the curtailment of RES and the use of fossil fuel. In this study, the savings in distribution network are the most visible benefits.

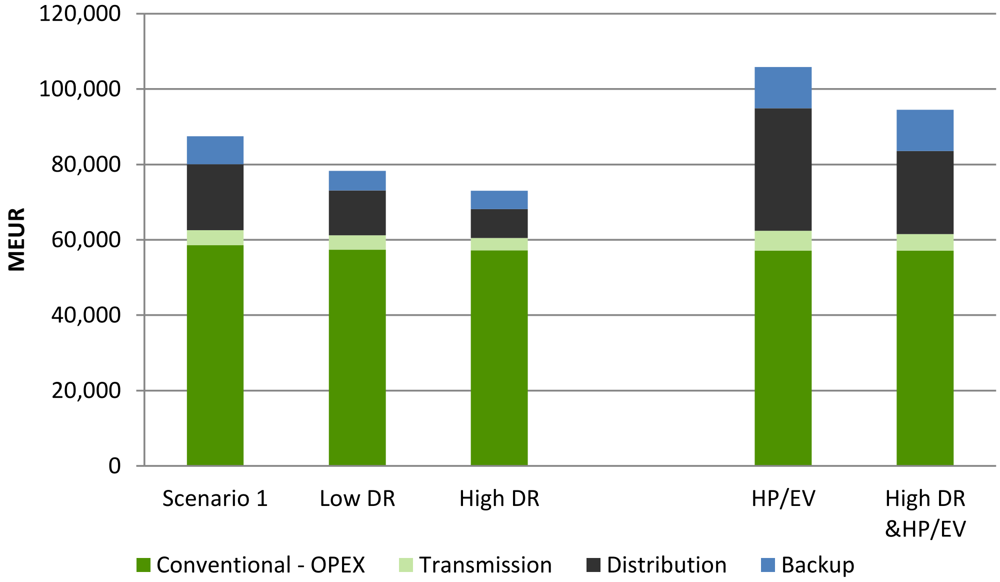

Figure 14 Economic benefits of demand response

The discussion in thus study has shown that, besides demand response, there exist a multitude of possible options, some of which can be implemented relatively easily at limited costs, whereas other may be more difficult or costly to introduce. Table 3 lists a number of potential measures, which may help to facilitate the integration of RES-E. For each of these measures, Table 3 also specifies in which areas they may allow for cost savings, i.e. generation, transmission or distribution. This summary shows that some measures, like demand response or the use of 'smart grid' technologies, may lead to savings in several areas. Conversely, our analysis also indicates that the benefits from many other measures can be expected to be largely limited to one particular area. It is also visible that many of these measures may help to reduce the need for back up generation or distribution expansion. In contrast, there appear les options for reducing the need for transmission expansion, which is in line with our earlier conclusion that the need for transmission expansion is mainly driven by the regional distribution of different types of variable RES-E across Europe.

Finally, it is worth noting that the measures at the bottom of Table 3 are generally related to larger investments and/or significant improvements of technology. In contrast, we believe that the measures in the upper half of Table 3 can be introduced with limited costs as they are largely based on existing technology and do not require major changes to the current infrastructure.

Table 3 Summary of technical measures that may facilitate the integration of variable RES

Measure	Areas of possible cost reductions		
	Generation	**Transmission**	**Distribution**
Ancillary services from RES-E plants	✓		(✓)
Utilisation of demand response	✓	✓	✓
Regional sharing of operating reserves	✓		
Improved RES-E forecasts	✓		
Reactive power from DG-RES			✓
Restricted DG-infeed by solar PV			✓
Improved network monitoring and control		✓	
More flexible conventional plants	✓		
Technology improvements of RES-E	✓	(✓)	(✓)
Pan-European overlay grid		✓	
Innovative transmission technologies		✓	
Use of 'smart grid' technologies	(✓)		✓
Decentralised storage	(✓)		✓

Based on the quantitative analysis in this report, it is possible to assess the potential benefits, which many of these measures may bring to a future power system with a high penetration of variable RES-E, including a large share of DG. Figure 15 presents an indicative comparison of the costs and net benefits of the technical solutions listed in Table 3. We note that it has not been possible to investigate the potential impact of every single measure in detail in this study, and that an analysis of the costs of the different measures as beyond the scope of this study. Consequently, we emphasise that the comparison in Figure 15 should be understood as indicative, and that a more detailed investigation of individual aspects may very well reveal further differences that are not shown in Figure 15.

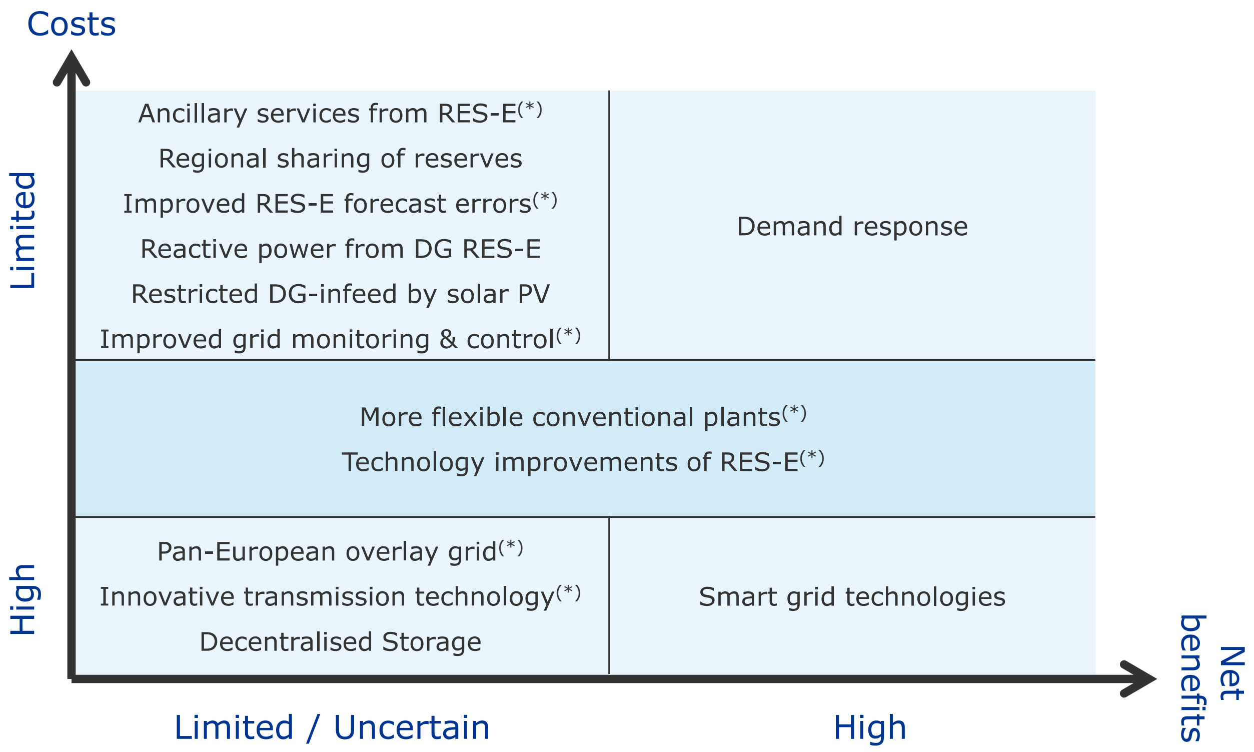

Figure 15 Indicative comparison of costs and net benefits for selected technical solutions

Note: (*) indicates measures for which the potential economic benefits have not been quantitatively estimated in this study, or not a sufficient degree of detail.

Against this background, our analysis has shown that the measures listed on the right of Figure 15 have are principally able to deliver major savings to power systems with a large share of variable RES-E, with annual savings of in excess of € 10 to 20 billion. Conversely, our analysis indicates much smaller savings for the measures on the left of Figure 15, of somewhere between less than € 1 billion and up to € 5 billion annually. In addition, this group includes several measures, for which this study has not delivered a quantitative estimate of the potential economic benefits. The same applies to the two measures in the centre of Figure 15, although we assume that both of them may potentially allow for substantial savings.

Figure 15 suggests, therefore, the following conclusions with regards to the value and attractiveness of the different measures identified in Table 3 above:

- Demand response seems to represent the most attractive option as it is able to deliver major savings but can be used at limited costs. In particular, demand response can facilitate the integration of DG, i.e. when being provided not only by large but also by smaller and medium-sized consumers. Similarly, additional volumes of DR will be available in situations with an increasing penetration of heat pumps and electric vehicles, helping to mitigate the challenges caused by the additional (peak) load from these applications.
- Secondly, our analysis strongly suggests pursuing the different measures listed on the top left. Although the individual contribution by each of these measures may be limited in many cases, they may lead to substantial savings when used in combination. Moreover, these measures represent 'no regret' options that can be implemented at limited costs since they do not require substantial additional infrastructure or major technological developments.
- In a way, the two measures in the centre of Figure 15 can also be considered as potential 'no regret' options, or even as an essential precondition for the large-scale integration of variable RES-E into the European power sector. However, it is difficult to assess the costs and timelines at which such improvements may be realised. Indeed, it seems that these two options rather represent desirable outcomes that should be supported by market design (see below) as well as research & development, but that it may be more difficult to directly control them.
- Smart grid technologies, such as area and in-line voltage control or voltage regulated distribution transformers, may allow for potential savings. But the use of these technologies requires potentially major investments. Moreover, the economic value of these measures strongly depends on the local situation, such as the existing design and state of the distribution network, the type and penetration of variable DG etc. Consequently, the potential benefits of smart grid technologies may need to be carefully weighed against costs in each case, in order to ensure that their deployment delivers true economic benefits to the system.
- Similar considerations apply to the last group on the bottom left of Figure 15. Due to the major investments required, the costs and benefits of these options need to be carefully analysed. For the particular case of decentralised storage, we furthermore emphasise that the potential benefits of this option critically depend on major cost reductions of this technology. Based on the results of this study, it therefore appears uncertain whether decentralised storage will already represent an economically efficient solution by 2030[12], even when assuming a major growth of variable DG.

[12] Our analysis does not generally support the use of electricity storage in the time horizon until 2030, mainly due to high capital cost, conversion losses and the type and regional distribution of RES-E (largely wind power) in most of the scenarios considered. Still, decentralised storage (in combination with solar PV) may potentially become a promising solution under certain circumstances and assuming a major decline in investment costs.

Despite these cautioning comments, we note that the measures presented in Table 3 and Figure 15 should not be considered as a set of mutually exclusive alternatives. Instead, they rather represent a menu of suitable measures, which can and indeed should be used in combination.

Implementation of these technical solutions may need to be supported by regulation and market design, or require other preconditions to be met. Table 4, therefore, shows a separate view and differentiates between measures and/or changes, which require:

- Technological advances, for instance in the areas of equipment design, operational practices or forecasting, monitoring and control;
- Improvements of the current and envisaged market design, including interactions between different stakeholders in the electricity market and/or remuneration;
- Development of the regulation of network operators;
- Major investments into new assets, including generation, transmission, distribution or storage and, to a lesser degree, monitoring, communication and control.

Table 4 Preconditions for implentation of potential technical measures

Measure	Changes / Improvements in area of			Substantial investments required
	Technology / Operations	Market design	Regulation	
Ancillary services from RES-E plants		✓		
Utilisation of demand response		✓	(✓)	
Regional sharing of operating reserves	(✓)	✓		
Improved RES-E forecasts	✓	(✓)		
Reactive power from DG-RES		✓		
Restricted DG-infeed by solar PV		✓		
Improved network monitoring and control	(✓)		(✓)	(✓)
More flexible conventional plants	✓	(✓)		✓
Technology improvements of RES-E	✓	(✓)		✓
Pan-European overlay grid	✓		(✓)	✓
Innovative transmission technologies	✓		✓	✓
Use of 'smart grid' technologies	(✓)		✓	✓
Decentralised storage	(✓)		(✓)	✓

In line with our previous comments, Table 4 shows that most of the measures in the first group can principally be implemented by adjusting and further developing the design of European electricity markets. In this context, it is worth noting that many of these measures are implicitly covered by or are at least fully compatible with the Target Model for the electricity market. Although we do acknowledge that implementation of many of these measures would involve considerable complexity, they do not require any fundamental changes but can principally be implemented within the currently evolving legislative and regulatory framework at a European and national level. Moreover, they can largely be implemented with existing technologies and at limited costs, such that we do not foresee any fundamental barriers to their deployment.

In contrast, many of the measures listed in the lower half of Table 4 require further technological advances as well as major investments into new assets. Apart from uncertainty on the evolution of future technology and costs, these measures require access to sufficient funds in both the competitive and regulated sectors, i.e. for operators of generation and storage assets as well as transmission and distribution networks, respectively. This requires sufficient incentives to invest and may, therefore, require further refinements to regulation and market design.

Market Impacts and Potential Barriers for Investments

In addition to an in-depth analysis of future infrastructure requirements, this study has also analysed the resulting impacts on electricity markets as well as the operation and profitability of conventional and renewable generation technologies.

The studies show that the fuel mix and average wholesale price levels may change significantly over time, reflecting the underlying changes in the generation structure. Furthermore each scenario's assumptions on the development of fuel and CO_2 prices will impact energy prices. We have identified several effects that may impact market operation and affect investment propositions of market participants:

- In line with an increasing penetration of variable RES-E, some scenarios are characterised by an increasing volatility of wholesale market prices. This development furthermore is strongly correlated with the degree of transmission expansion; whereas scenarios with optimised network reinforcements lead to converging regional prices and limited volatility, a lack of or limited transmission expansion may result in major regional disparities and extreme levels of volatility in some areas.
- Depending on the mix of RES-E generation technologies, the profile of wholesale market prices may change substantially. In line with recent developments in Central Western Europe, the simulations show that especially a growing penetration of solar PV depresses traditional peak / off-peak ratios but may lead to short but more pronounced daily peaks during shoulders hours in the morning and evening.
- As the penetration of renewable power generation grows, the role of conventional power generation capacity changes. Running fewer operating hours, operation and revenues of conventional plants will be less predictable, and they will become more dependent on peak energy prices to earn the margins required to cover their fixed operating and investment costs. In addition, increasing price volatility and short-lived price spikes will require more flexible generation, which is able to react more quickly to changing market conditions.
- Due to the variable production by RES-E, European power systems will principally be in need of increasing volumes of ancillary services. This principally creates additional income for flexible generators that earn less from wholesale markets but can provide ancillary services to the system. When assuming that variable RES-E are incentivised to provide ancillary services and that balancing services are shared by TSOs on a regional basis, however, the additional income to conventional generators may remain limited. In addition, an increasing contribution from other sources of flexibility that have not been traditionally used, such as demand response, may further reduce prices and generators' revenues in the ancillary services markets.

This study has therefore specifically analysed the profitability of different generation technologies, in order to assess whether the scenarios considered and current market arrangements may lead to potential barriers for investments into new generation infrastructure. With regards to the profitability of different generation technologies and incentives to invest into new plants, the results of the study lead to the following observations and conclusions:

- Increasing reliance on short-lived price spikes might increase the risk profile of generation investments and the financing costs they face. However, increasing price volatility may also reward more flexible generation, which is able to react more quickly to changing market conditions.

- The profitability analysis of different generation technologies indicates that existing generators will generally be able to recover their fixed O&M costs throughout the whole modelling range. Nevertheless, periods of temporary over-capacity, caused by the rapid increase of RES-E, may force some older plants to retire before the end of their economic lifetime.
- The value of additional electricity storage seems to remain limited in the time horizon until the year 2030. Consequently, it is not surprising to see that market revenues do not generally justify investments into new electricity storage.
- Although the modelling framework does not allow drawing strong conclusions on the extent to which new conventional generation technologies are able to recover their fixed O&M and construction costs, the results do show that necessary investments into new conventional plants may be profitable.
- While is it true that some inefficiencies in energy markets may undermine the efficiency of investments taken by participants in the energy market, these inefficiencies have not been modelled within our framework, which fundamentally assumes a well-functioning energy market. Therefore, any suggestion from the modelling results that prices do not remunerate investment in new capacity should not lead to the conclusion that the energy market will not remunerate investment in the generation capacity required to integrate RES-E into the EU power system efficiently.
- The analysis carried out in this study does suggest that the profitability of renewable technologies improves towards 2030. Still, the overall level of power prices will remain too low to remunerate investments in most RES-E technologies. This suggests that subsidies will continue to be required to support the scale of RES-E development assumed in this study, in particular in the case of offshore wind and solar PV.

Options for Enhancing Regulation and Market Design

Efficient integration of renewables can be best achieved by implementing power market designs, network charging arrangements and renewable support schemes that promote effective competition and economically efficient outcomes. In principle, the aim of promoting economically efficient outcomes is best achieved through well-functioning, competitive markets, in which participants are exposed to the marginal costs they impose on the system, and receive the marginal benefit they provide to the system through revenues or cost savings. Similarly, network charges should send efficient locational signals to network users, whilst regulation of network companies must ensure that an efficient level of investment takes place in distribution, transmission and interconnection to accommodate renewables expansion efficiently. Finally, support schemes for RES-E support should not only promote technological innovation and efficient investments but also provide incentives for efficient trading and despatch decision of existing RES-E plants.

Against this general background, this study has discussed different options that can be taken in this respect with regards to the design of efficient energy markets, electricity network regulations, and renewable electricity support policies. Many of these options mentioned reflect ongoing developments on the way towards implementation of the target model for the electricity market, such as regional integration of wholesale and ancillary services markets. Similarly, other measures have already been the subject of extensive discussions, like the possible need and benefits of a capacity mechanism or the challenges around the remuneration of network investments that are providing economic benefits to multiple countries or stakeholders in an interconnected system.

Table 5 presents a number of selected measures that are specifically related to the technical challenges and solutions identified above. The first two options are specifically aimed at improving the way, in which flexibility is priced in and allocated between the energy and ancillary services markets. The third and fourth items are both related to network regulation and the objective of providing incentives for efficient investment decisions by network operators. The last two options finally are mainly directed at RES-E generators, although locational signals may equally serve to promote efficient investment and operational decisions by conventional generation and load.

Table 5 Selected measures in regulation and market design

Measure	Market Design	Network Regulation	RES-E Support
Reduced duration of trading intervals	✓		
Close-to-real time markets for ancillary services	✓		
Changes to network planning standards		✓	
Encourage innovative ("smart") network technologies		✓	
Use of locational network charges		✓	
Provide incentives for market-supportive behaviour and reduction of imbalances			✓

Not all of these measures will be equally effective in mitigating the challenges of integrating RES-E, and they will also differ in terms of the costs they may impose on consumers. In order to put the different measures into perspective, it thus seems useful to consider the contribution of different cost items to total incremental costs of electricity supply:

- Incremental costs of electricity supply are clearly dominated by CAPEX for new RES-E plants, followed by OPEX of conventional plants, i.e. costs for fuel and CO_2 emissions;
- Apart from CAPEX for new conventional plants, the costs of distribution expansion represent another major cost item; and
- Investments into additional back-up capacity and transmission expansion, though being substantial, do only represent a small fraction of total costs.

Based on these considerations, Figure 16 presents an indicative comparison of the costs and benefits of the changes to regulation and market design identified in Table 5.

The two measures on the top right can principally be expected to support major savings at limited costs. As mentioned above, revised network planning standards at reaching an optimal trade-off between constraint and investment costs for connection of variable RES. If implemented properly, this may help to avoid unnecessary investments and/or undue restrictions to new connections especially in distribution networks, noting that distribution expansion accounts for a considerable proportion of total incremental costs. Similarly, the removal of preferential rights of variable RES-E during daily system and market operation may lead to major savings. Overall, these two measures thus appear as particularly valuable.

As mentioned above the use of "smart" network technologies represents a potentially very promising technical solution, which may lead to major savings. However, the design of truly efficient regulatory regimes for this purpose is highly complex and still under discussion. In addition, this option also bears a risk of significant additional costs when not properly implemented, i.e. in the form of rewarding unnecessary investments. Despite its potential merits, this measure may, therefore, have to be considered with some caution in comparison with the first two measures.

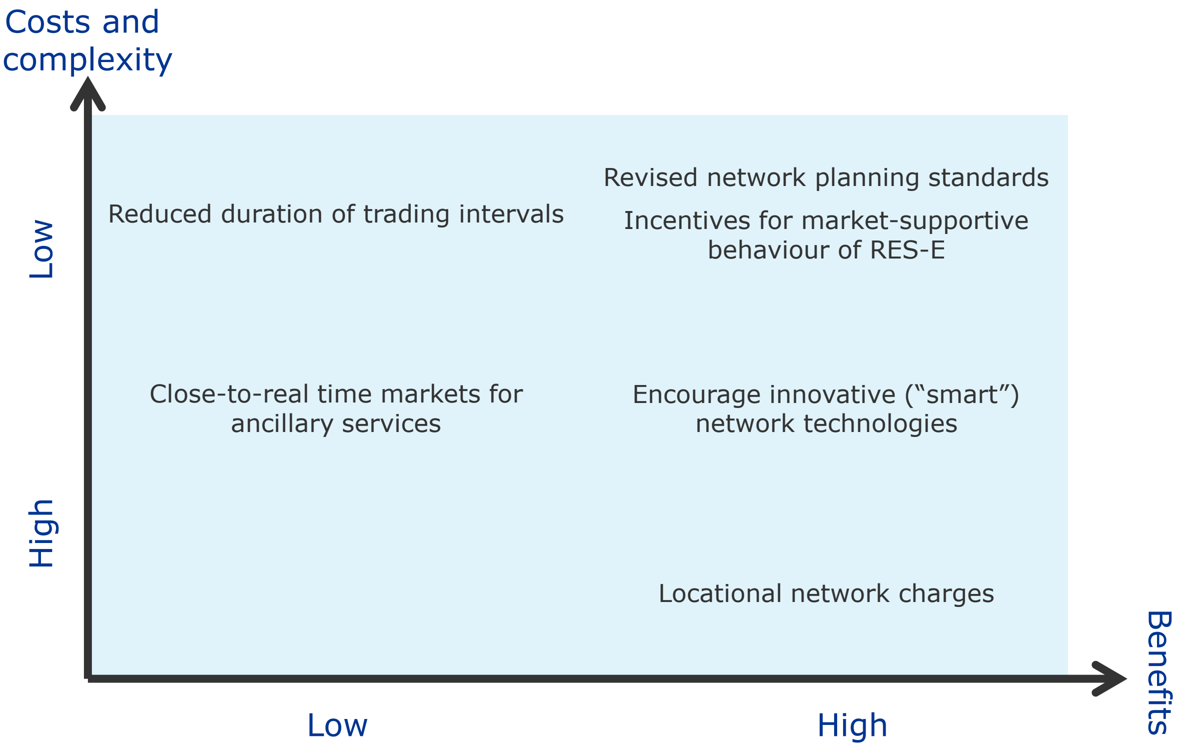

Figure 16 Indicative comparison of costs and benefits of selected changes to regulation and market design

The benefits of shorter trading intervals or close-to-real-time markets for ancillary services can be expected to remain more limited since they will mainly allow for a limited reduction of OPEX and, potentially, some back up capacity. Nevertheless, reducing the length of trading intervals represents a measure that can be implemented quite easily such that it may deserve further study. Conversely, the introduction of close-to-real-time markets for ancillary services, where the allocation of ancillary services to different service providers is not decided upon on the day ahead (or even before) but shortly before real time, may become fairly complex, especially when being considered at a regional or even European level. Moreover, we expect that a major part of the potential savings can already be reaped by full implementation of the target model, i.e. a liquid pan-European intraday market, such that the incremental benefits of this measure may remain limited.

Finally, an extended use of locational network charges may incentivise a balanced distribution of variable RES-E (and conventional plants) across different regions as well as on a more scale within a distribution network, i.e. both in terms of horizontal and vertical location. This may allow reducing the need for network expansion, especially at the distribution level. Similar to the promotion of "smart" network technologies, however, the design of truly cost-reflective locational charges at the distribution level may become highly complex.

Recommendations

The modelling results in this study have shown that future infrastructure requirements as well as the overall costs of electricity supply are strongly influenced by the choice and regional distribution of different types of variable RES as well as the design and planning of individual assets and the overall electricity supply system. Our analysis suggests, therefore, that technical and regulatory measures, as well as wider efforts in the areas of research and development, should aim at the following objectives, in order to facilitate the integration of variable RES-E and reduce the need for additional infrastructure:

- Facilitate the use of demand response;
- Incentivise parallel **expansion of RES-E and network infrastructures**, which aims at a balanced regional distribution and technology mix of RES-E;
- Promote a **balanced distribution of (variable) DG** across different network levels and between different types of distribution networks (e.g. urban vs. rural areas);
- **Support technology improvements of RES-E plants**, which lead to increased capacity factors and decreasing variability; and
- Stimulate the use of innovative transmission and "smart grid" technologies.

We have considered a range of technical solutions and regulatory measures, which may considered in order to support these overarching goals. In addition, we have assessed the individual measures with regards to their effectiveness, costs and complexity of implementation. Based on this discussion, Table 6 provides a list of selected recommendations with regards to technical design and operations, on the one hand, and regulation and market design, on the other hand.

Table 6 List of selected recommendations

	Technical Design and Operations	Regulation and Market Design
Priority measures	• Use of demand response • Provision of ancillary services by RES-E • Regional sharing of operating reserves • Provision of voltage control by variable DG • Limited infeed by solar PV (% of capacity installed) • Improved network monitoring and control • Selective use of smart grid technologies	• Implement target model • Revised network planning standards • Incentives for market-supportive behaviour of RES-E • Encourage innovative ("smart") network technologies
Additional measures to be considered	• Use of innovative transmission technology • Pan-European overlay grid • Use of decentralised storage	• Locational network charges • Reduced duration of trading intervals • Close-to-real time markets for ancillary services
Other areas to be supported (R&D)	• Reduced forecast errors (RES-E) • Technology improvements of RES-E, conventional plants, storage and innovative network technology	

More specifically, we have grouped our recommendations into three different categories. First of all, Table 6 identifies a number of **priority measures**, which can be expected to both effective and efficient, i.e. which can be implemented with limited costs and complexity and which can either be expected to deliver major economic benefits, or otherwise represent "no-regret" options, including the selective use of smart grid technologies. Based on our analysis, these priority measures should clearly be supported by future European policy and regulations. We emphasise that full implementation of the target model for the electricity market clearly is among the most important steps as it implicitly covers or is at least fully compatible with many of the other priority measures listed in Table 6. Among others, this also applies to the promotion of demand response, which our study has revealed as one of the most power technical measures.

Secondly, Table 6 also list a number of **additional measures to be considered**. These measures may potentially allow for significant savings. However, their true benefits either appear uncertain or may only apply in certain areas or situations, like the construction of a European overlay grid or the use of decentralised storage. Likewise, the cost and complexity of changes to regulation and market design may outweigh the potential benefits of these measures when not being implemented properly. In contrast to the first category, application of these measures should be subject to further study, potentially on a case by case basis, in order to ensure that they really lead to net economic benefits.

Finally, Table 6 includes a summary of **other areas deserving further support**. This group includes technical improvements for instance in terms of equipment design or forecasting accuracy. Our analysis suggests that corresponding improvements may also facilitate the integration of variable RES-E and reduce costs, but such improvements cannot be directly controlled and directed. To a certain extent, one may reasonably expect that such technological advances will be indirectly driven by the electricity market, i.e. assuming that the measures mentioned above will reward flexibility, or more generally the capability of supporting the system. From a policy perspective, these areas may nevertheless deserve additional support, for instance in the form of support to future research and development.

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1 INTRODUCTION

The promotion of renewable energies represents a key pillar of the Commission's broader energy and climate objectives of reducing greenhouse gas emissions, improving the security of energy supply, diversifying energy supplies and improving Europe's industrial competitiveness. Although considerable progress has already been achieved over the past 14 years, the share of renewable energies will have to grow at a much faster pace to achieve the EU's 20% target for 2020. Moreover, it is generally expected that this development will have to continue after 2020, in order to achieve the EU's goal of decarbonising the European energy sector by 2050. In parallel, the Commission seeks to complete the establishment of the Internal Electricity Market, which requires that renewable energies are increasingly integrated with the competitive market.

The development to date has shown that the emergence of fluctuating renewable energy sources creates new challenges for the power system and the electricity markets alike, which will grow with an increasing penetration of renewables. It is therefore clear that the European electricity sector will have to undergo fundamental changes over the next decades. These changes will concern the entire value chain in the electricity system, i.e. transmission and distribution networks, generation, load and storage. In addition, it will be necessary to address the necessary regulatory reforms with regards to the regulation of network investments, network access and tariffs, and the design of the spot and ancillary services markets.

In recent years, the Commission and other relevant stakeholders, such as ACER/ERGEG, ENTSO-E as well as national regulators and TSOs, have therefore spent substantial efforts on analysing the resulting challenges and identifying potential solutions at the policy, regulatory and technical level. Most of this work has however been focused on the development to 2020, whilst so far limited efforts have been spent on investigating the further development after 2020 only. Similarly, most of the analysis to date has focused on the implications at the transmission level. Conversely, it is widely expected that much of the growth of renewables past 2020 will be based on decentralised generation.

As recent developments in for instance the German electricity market have shown, this will result in additional challenges for distribution networks, which are not yet fully understood. Apart from the potential need for network extensions, it is therefore often argued that it will also be necessary to engage the demand side in the future, i.e. by means of demand response, and, possibly, to invest into new storage technologies at both the transmission and distribution level. In addition, these developments will create the need of effectively coordinating the operation of a very large number of individual market participants, both at a local (distribution) and at a global (transmission) level.

Against this background, the current study provides the Commission with a thorough analytical framework for the analysis of the infrastructure, regulatory and policy requirements of the power sector in a range of energy sector scenarios with high energy efficiency and a high share of renewables. In particular it allows for a more detailed understanding of how distribution networks, generation and storage, and transmission interact, both locally and across Europe, and what the resulting implications are with regards to the regulatory framework.

More specifically, the Study addresses the following key topics:

- Identification of plausible grid solutions at the transmission and distribution level for the year 2030, including infrastructure requirements as well as operational strategies;
- Determination of grid extensions at the transmission and distribution level, which are required to enable the intended penetration of renewable energies ;

- Determination of the possible role, which different generation and storage technologies as well as demand response may have to play;
- Identification of potential barriers for the growth of distributed generation;
- Assessment of the risk of insufficient incentives for investments into both renewable and conventional generation (as well as storage) in the current market model, which may undermine the reliability of the power system;
- Identification and description of regulatory reforms in the areas of market design, network regulation and support schemes for renewable energies, which may be necessary to manage the increased penetration of electricity from renewable energy sources.

A fundamental precondition for the analysis outlined above obviously is the need to quantify the system costs of integrating large amounts of renewable generation into the future EU electricity system, under consideration of different generation and load mixes. A thorough analysis of these issues requires comprehensive modelling of the electricity system, including generation, transmission as well as distribution and storage. In this context, it is important to note that the costs of integrating large amounts of renewables into the power system are driven by radical changes on both the supply and demand side of the future EU system. It is therefore necessary to consider both supply side driven and demand side driven system integration costs.

Following the structure of the study, we subsequently outline its methodological approach, the underlying assumptions, the insights derived from its analysis and the assessment of technical measures and regulatory options to meet the arising challenges for the electricity system.

- Methodology (Chapter 2)
  - To determine optimal transmission and generation expansion in Europe and to simulate the impacts on electricity markets a combination of two fundamental models is used: Whereas RES-E expansion relies on scenario assumptions, optimal conventional capacity expansion is simulated on the basis of the electricity market software PLEXOS that is also used for market analysis. Expansion of transmission infrastructure and back up generation is simulated on the basis of DSIM, a model developed specifically for this purpose.
  - To depict the current transmission grid for the simulation analysis, a simplified grid model was developed based on a zonal transport model with a total of 74 individual nodes and ca. 165 existing and potential (inter-) connections. The grid model covers all Member States that are physically part of the interconnected electricity market within the EU, as well as Norway, Switzerland, Albania and the remaining members of ENTSO-E in South-Eastern Europe.
  - As for distribution grids a set of typical networks was created, based on information on network design policies and standards in different Member States, representing the real situation in each of the Member States. The representative networks provide the basis for the detailed distribution analysis and the determination of network reinforcements costs.
  - Further assumptions underlying the model analysis include standard cost and unit sizes of conventional and renewable generation capacity and future load. Technical assumptions are based on DNV GL data, whereas future energy consumption paths were taken from the EU Energy Roadmap 2050.

- Basic scenarios and Sensitivities (Chapter 3)
  - Focussing on RES-E expansion, three main scenarios were considered in the model analysis, based directly on scenarios from the EU Energy Roadmap 2050: an 'Optimistic Scenario' corresponding the ER 2050 scenario 'High RES-E', characterized by a fast expansion of RES-E based generation, a 'Middle Scenario' (corresponding to the 'Diversified Supply Technology' scenario in ER 2050) and a 'Pessimistic Scenario' (corresponding to ER 2050 scenario 'Current Policy Initiatives') with a low RES-E expansion trajectory. All required assumptions concerning regional and technological developments were taken from the PRIMES based simulations underlying the ER 2050.
  - Additionally, a number of sensitivities were calculated to analyse specific topics. These include load-driven RES-E expansion, the increased use of heat pumps and electric vehicles and delayed or no transmission expansion.
- Results: Infrastructure requirements & market impacts (Chapter 4 & 5)
  - The presentation of results starts with an overview of necessary investments into generation, transmission and distribution infrastructure for each of the scenarios outlined above. In addition, an overview is given of the development of electricity generation in the different scenarios, including the generation structure, curtailment of RES-E, fuel consumption, and CO2 emissions.
  - Secondly, this chapter discusses the impact on the costs of electricity supply, including investments into new infrastructure as well as variations in operating expenditure (i.e. mainly fuel costs).
  - The main cost drivers as well as relevant technical barriers for increasing the use of RES-E are identified, and the specific role and impact of decentralised generation is discussed.
  - Furthermore, for each scenario the report outlines the development of prices in wholesale and ancillary services markets, and the impact on the profitability of selected generation technologies and pump storage.
  - Based on the results of the simulation analysis potential barriers for investments into generation and storage are identified and discussed.
- Assessment of Technical Measures & Regulation and Market Design (Chapter 6 & 7)
  - A number of technical measures to meet the demand of a RES-E dominated power system are discussed and assessed. These include part load operation by conventional power plants, the provision of ancillary services by variable RES-E generation, demand response systems, the deployment of centralised and decentralised storage technologies, alternative transmission & distribution technologies and network operations.
  - Options for regulation and market design are presented and –as far as possible- evaluated on the basis of the modelling results. This encompasses regulation of transmission expansion and operation, grid access of RES-E and conventional power generation, alternative RES-E support schemes and electricity market design (with a view on capacity mechanisms).
- Ultimately, Chapter 8 concludes and presents the main findings and recommendations, based on the modelling results and the assessment of technical and regulatory options.

2 ANALYTICAL FRAMEWORK AND GENERAL ASSUMPTIONS

2.1 Generation and Market Modelling

2.1.1 Outline of Modelling Approach and Models

As illustrated by Figure 17 we are using two different models for the determining the optimal generation and transmission infrastructure and simulating the market outcome for each of the scenarios described in Chapter 3:

- First, we determine the optimal expansion of conventional power plants in a commonly used tool for generation and market modelling (PLEXOS); before
- Optimising transmission infrastructure and back up generation by means of a proprietary tool (DSIM) that has been specifically developed by ICL for this purpose.

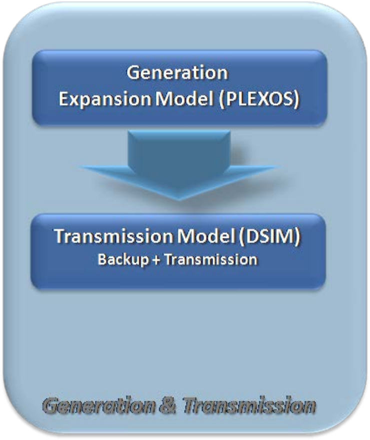


Figure 17 General approach for generation and transmission modelling

In a first step, we have established a set of detailed data sets for each of the scenarios. Among others, this includes the specification of the future development of RES-E capacity, nuclear plants, load, fuel and CO_2 prices, emission constraints, as well as the transmission model which is described in Chapter 2.2. In addition, we have specified five different generation technologies that can be endogenously built by the capacity expansion model, i.e.:

- Coal-fired steam turbines, with or without CCS;
- Combined-cycle gas turbines (CCGT), with or without CCS; and
- Open-cycle gas turbines (as back up capacity).

Section 2.1.2 below provides a summary of the assumed technical and economic characteristics for these candidate technologies as well as for other types of power plants.

This input data is then fed into the capacity expansion module of the PLEXOS model, in order to determine the optimal generation expansion path for the period 2020 to 2030, with a further lookout to 2050. This model automatically closes down existing plants at the end of their technical lifetime[13] and

13 Or potentially before, in case capacity is no longer needed

adds new generation capacity such that the overall generation costs are minimised. For this purpose, the capacity expansion module considers the initial investment cost and ongoing fixed cost as well as the expected variable operating costs, i.e. mainly for fuel and carbon emissions. Consequently, new capacity of a given type is built only if it represents the least-cost solution over the entire time horizon of the study.

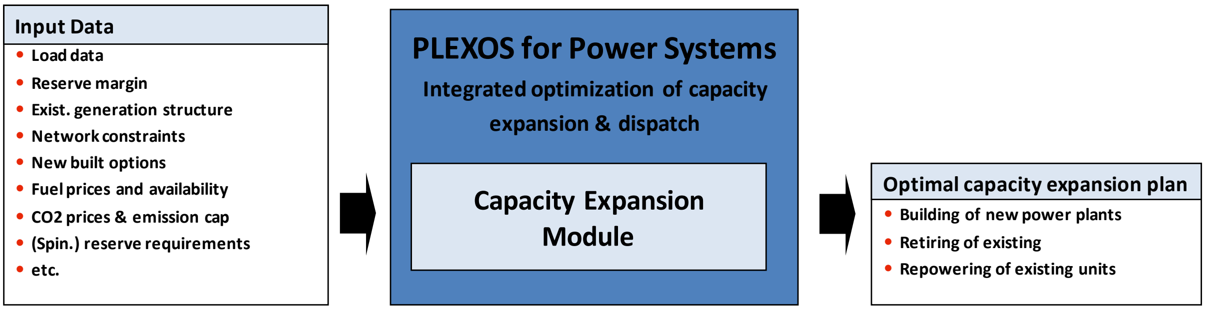


Figure 18 Approach for long-term capacity expansion (PLEXOS)

Thereafter, we use Imperial College's DSIM model to determine the need for transmission and back up generation (as well as to simulate the operation of the spot markets). The infrastructure (generation and transmission) evaluation model has been specifically built to capture 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. More specifically, this model seeks to minimize the total system costs comprising:

- Additional transmission network capacity;
- Additional generating capacity as required to ensure reliability; 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 (additional generation back up), additional transmission infrastructure, RES-E curtailment and transmission constraint costs incurred for network congestion management. In contrast to other models, DSIM has been specifically designed to ensure reliability in a power system with a large penetration of variable RES-E. The model also optimises the sharing of generation capacity reserves across the system through transmission links, so that reliability requirements can be met at minimum costs through making full use of interconnectors.

The integrated reliability assessment calculates the loss of load expectation (LOLE) by assessing whether adequate generation will be available for each hour of the year to meet the demand. This is based on an array of probabilistic inputs, which the model takes into account. As illustrated by Figure 19 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 (CSP) 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. The economic trade off is made by assessing the annualised costs of new transmission and back up generation capacity against the loss of load (with an assumed cost of €50,000 per MWh), and subject to a maximum LOLE of less than 4 hours per year.

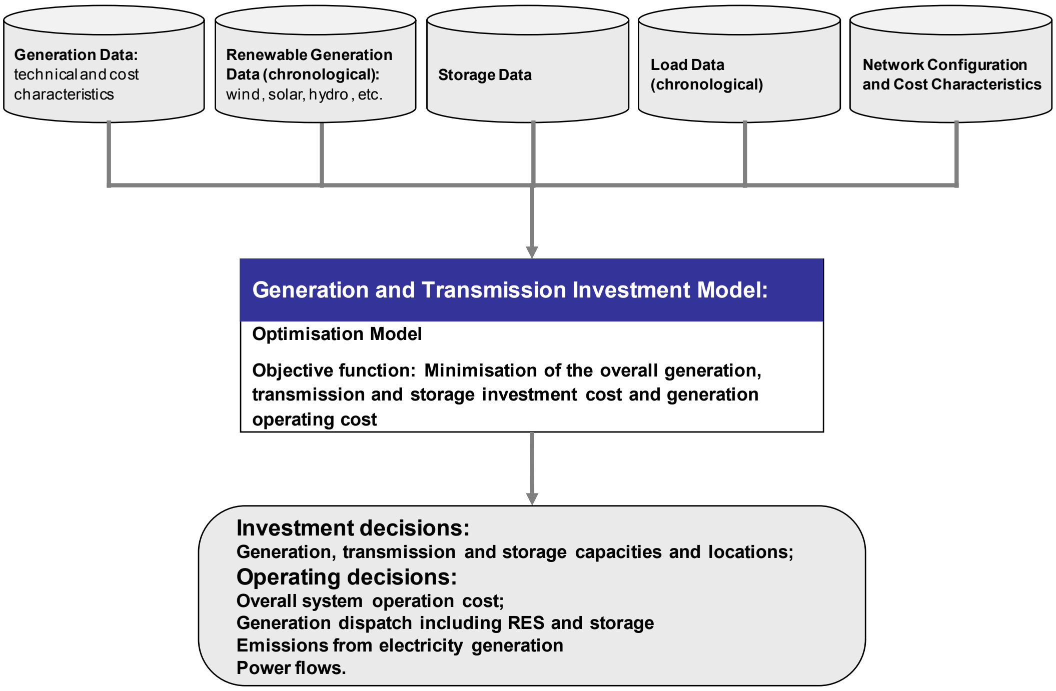


Figure 19 Structure of the Generation and Transmission Investment and Operation Model (DSIM)

The generation and transmission model principally covers the entire European market and considers the chronological development of variable RES-E and demand on an hourly basis for a full year. As such, the model captures both the influence of variable production from wind and solar power on generation dispatch and the need for reserve and back up capacity as well as the positive effects, which regional integration has in this respect[14].

2.1.2 Specific Assumptions

Technical and Commercial Characteristics of Generation Technologies

In order to limit the complexity of the generation model, we have grouped all plants into a total of 15 basic generation technologies. All existing plants, as well as plants that are not 'built' by the generation expansion model, are assigned to these basic categories. Table 7 provides an overview of the main operational characteristics for all generation technologies that are not based on RES-E.

14 I.e., the relative variability of wind and solar decreases as fluctuations are relatively lower when aggregated over a larger area.

Table 7 Assumptions on operational characteristics of existing conventional plants

Technology	Standard unit size	Thermal efficiency	Operation & maintenance costs		Forced Outage Rate	Maintenance Rate
			Fixed	Variable		
	MW	% (LHV)	EUR/kW/a	EUR/MWh	%	%
Nuclear plant	750	35%	101	3.3	5.0	10.0
Steam turbine (lignite)	300	37%	26	3.3	5.0	8.4
Steam turbine (coal)	300	40%	31	3.3	4.4	8.4
CCGT	300	56%	11	1.4	3.2	7.3
OCGT (gas)	150	38%	7	1.4	2.0	4.4
Steam turbine (gas)	300	41%	26	2.4	3.2	7.3
Steam turbine (HFO)	300	41%	26	2.4	3.2	7.3

Source: DNV GL assumptions

Table 8 shows the same parameters for RES-E technologies. Please note that some parameters are not specified, either because they are not relevant for a given technology (such as thermal efficiency for solar and wind power power plants), or simply because we do not differentiate between individual units in our simulations.

Table 8 Assumptions on operational characteristics for RES-E

Technology	Standard unit size	Thermal efficiency	Operation & maintenance costs		Forced Outage Rate	Maintenance Rate
			Fixed	Variable		
	MW	% (LHV)	EUR/kW/a	EUR/MWh	%	%
Biomass	50	35%	26	3.3	4.4	8.4
Run-of-river hydro	n.a.	100%	44	1.0	2.0	5.0
Storage	n.a.	100%	44	1.0	2.0	5.0
Pump storage	n.a.	75%	44	1.0	2.0	5.0
Solar PV	n.a.	n.a.	20[a]	0	2.0	7.5
Solar CSP	n.a.	n.a.	114	3.3	6.0	n.a.
Wind offshore	n.a.	n.a.	68[b]	1.0	7.0	5.0
Wind onshore	n.a.	n.a.	30[a]	1.0	5.0	0.6

[a] – 1.5% of initial investment (for future installations); (b) – 3% of initial investment (for future installations)
Source: DNV GL assumptions

The development of RES-E and nuclear power plants is determined exogenously through a set of corresponding assumptions for each scenario. Conversely, the generation expansion model has the choice between five different types of conventional generation technologies. In addition to the 15 classes defined above, this latter group also includes coal- and gas-fired plants equipped with CCS, although we do not assume this technology to be available for large-scale commercial deployment until after 2030. As Table 9 shows, we furthermore assume continued technological progress for some of the existing technologies, i.e. coal- and gas-fired plants.

Table 9 Assumptions on operational characteristics for new power plants

Technology	Standard unit size	Thermal efficiency	Operation & maintenance costs		Forced Outage Rate	Maintenance Rate
			Fixed	Variable		
	MW	% (LHV)	EUR/kW/a	EUR/MWh	%	%
CCGT	300	62%	11.4	1.4	3.2%	7.3%
CCGT (CCS)	300	52%	18.0	2.4[a]	3.2%	7.3%
OCGT	150	39%	6.8	1.4	2.0%	4.4%
Coal plant	300	49%	30.8	3.3	4.4%	5.6%
Coal plant (CCS)	300	40%	48.7	6.6[a]	4.4%	5.6%

[a] – Plus 12 €/t for treatment, transport and storage of CO_2
Source: DNV GL assumptions

Finally, Table 10 provides an overview of additional information, which is required for optimal generation expansion planning. Please note that we have used a constant WACC of 10% in real terms for all technologies and years.

Table 10 Assumptions on capital costs and lifetime for new power plants (2012)

Technology	Capital Cost	Economic Lifetime	Technical Lifetime	Commercial market entry
	EUR/kW	year	year	
CCGT	787	25	30	
CCGT (CCS; 2030)	1,150	25	30	after 2030
OCGT	394	20	25	
Coal plant	1,875	30	40	
Coal plant (CCS; 2030)	2,300	30	40	after 2030
Wind onshore	1,128[(a)]	20	25	
Wind offshore	3,500			
Solar PV				
Ground mounted	1,200[(b)]	20	20	
Roof-top, large	1,400[(b)]	20	20	
Roof-top, small	1,550[(b)]	20	20	
Solar CSP	6,573[(a)]	30	30	

[(a)] – Based on Energy Roadmap 2050; [(b)] – Based on current market prices in Germany (Q3/2012)
Source: DNV GL assumptions, unless otherwise mentioned

For RES-E technologies, we furthermore assume future cost reductions due to continued learning effects; see Figure 20. The values for concentrated solar plants are equivalent to the values for the Energy Roadmap 2050 analysis. Conversely, we apply our own assumptions for wind and solar power, which start from current cost levels and assume further cost reductions, in particular for offshore wind and solar PV.

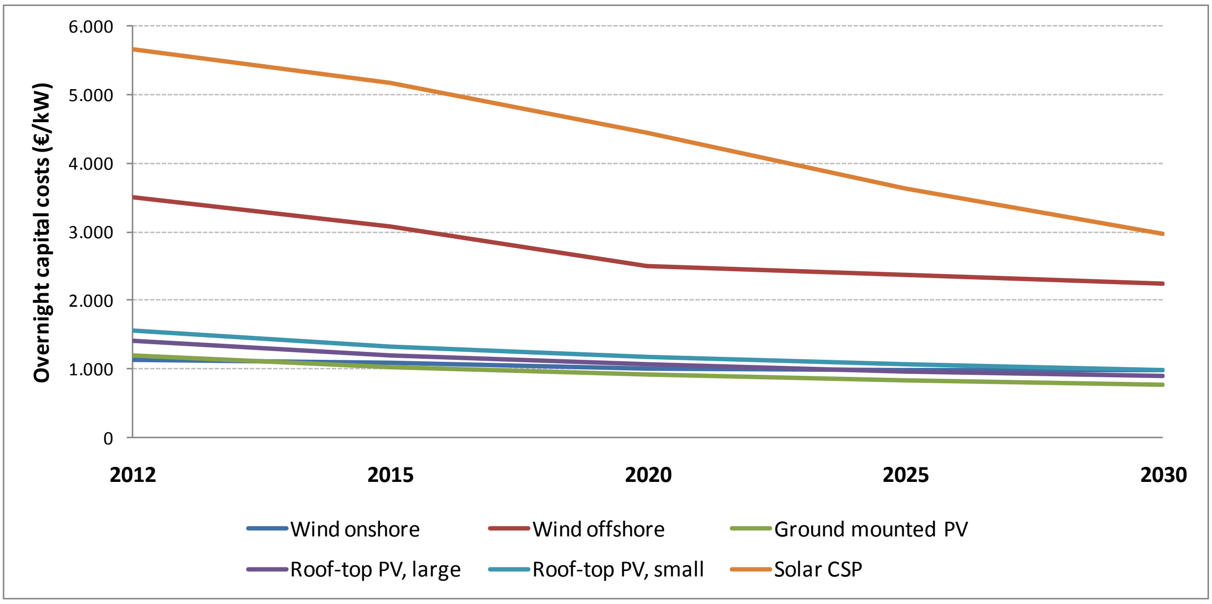


Figure 20 Assumed learning curves for RES-E technologies

Source: Energy Roadmap 2050 (CSP); DNV GL assumptions (all other technologies)

Demand

Assumptions on the development of annual consumption have generally been taken from the Energy Roadmap 2050. In each case, we use the national consumption of the EU-27 Member States, based on data from the PRIMES model provided to us by the Commission. Since this data is available for 5-year intervals only, the assumptions for the remaining years have been determined by linear interpolation. Similarly, we rely on other sources, such as the System Adequacy Forecast from ENTSO-E for those countries that are not members of the European Union. Please note that we have scaled up annual consumption by 7.5% in order to represent network losses at the transmission and distribution level.

Since our simulations are based on an hourly chronological model of the European power systems, it is furthermore necessary to create a set of hourly load profiles for each country and year. For this purpose, we use historic load profiles for each country as provided by ENTSO-E or national TSOs. For illustration, Figure 21 shows a typical daily profile for four European countries, i.e. Germany, Italy, Spain and the UK. These historic load profiles are then scaled to match total annual consumption in each country and year. Implicitly, this approach assumes that the overall pattern of demand will not change significantly until 2030[15].

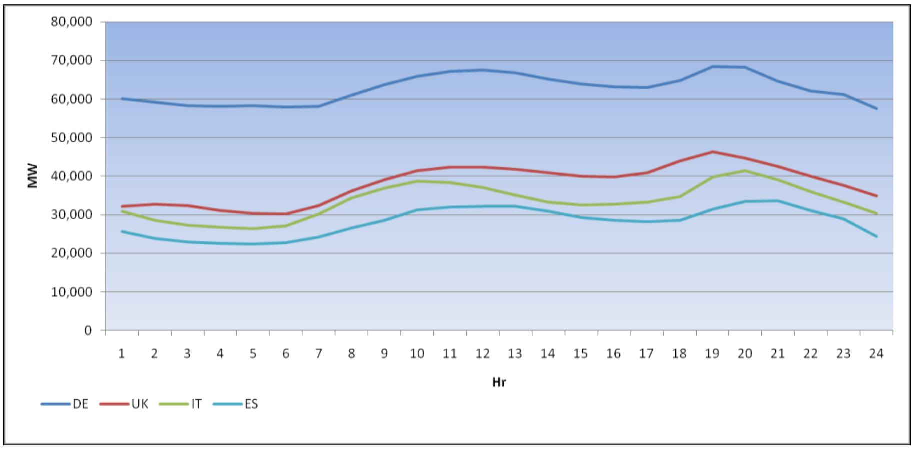


Figure 21 Examples of typical daily profiles for 4 European countries

In those countries where the transmission grid is represented by several nodes (see Section 2.2), national consumption is furthermore broken down across the different network zones in each country. Due to the lack of robust estimates on the geographical distribution of future demand in the PRIMES scenarios, we assume the spatial distribution to remain constant over time. Similarly, we assume the load profile for all network zones within a given country.

In line with the official reports on the Energy Roadmap 2050, we furthermore do not assume the wide-spread use of electric vehicles and/or heat pumps in the main scenarios. Similarly, we do not consider the flexibility potentially available from demand response in the initial simulations.

Renewable Energies and CHP Plants

Similar to the demand side, the resulting capacity figures have to be combined with hourly profiles for the detailed modelling, in order to properly represent the fluctuating production by wind and solar power. For this purpose, we apply a combination of different turbine models for wind power and a solar PV

15 In a later stage, we will therefore test for the potential impact of possible variations in the load profile.

model for different PV installations (see Table 11) as well as standard assumptions with regards to efficiency etc. For wind power, we furthermore differentiate between two types of onshore wind power plants (flat coastal and rough inland areas) as well as offshore plants. For solar PV, we calculate individual profiles for three types of firmly mounted rooftop installations, which are differentiated by horizontal angle and vertical inclination, and free standing modules. By assuming a certain share of these four different types, it is then possible to derive an aggregate profile by means of a weighted average[16].

The hourly profiles are based on representative time series of historic meteorological data, with a spatial resolution of approx. 50 km.

In order to maintain consistency with the assumptions and results of the Energy Roadmap 2050, the resulting profiles have finally been scaled such that they render the same capacity factors as used for the Energy Roadmap 2050.

Table 11 Data and methodology for determination of hourly wind and solar PV profiles

	Wind power	**Solar power**
Basis for calculations	Turbine model[17] a) Onshore (coastal / inland) b) Offshore	Solar PV model Weighted average of 3 rooftop modules [(a)] Free standing modules
Input factors considered	Wind speed[(a)]	Solar radiation (direct/diffuse) PV module temperature
Spatial resolution	2/3° long. / 1/2 ° lat.	
Temporal resolution	1 hour	
Determination of zonal profiles	Arithmetic average of each transmission zone	

[(a)] – Differentiated by horizontal angle and vertical inclination; [(b)] – At 100 m hub height

For hydropower, we differentiate between run-of-river, storage and pump storage plants. For storage and pump storage plants, we model available storage volumes, based on current plants and existing projects. Similarly, we allow for some short-term storage for run-of-river plants in those countries where a tangible volume is equipped with smaller ponds. For all plants with natural inflows, the available inflows are modelled on a monthly pattern, based on historical time series for each country or region.

In order to maintain consistency with the Energy Roadmap 2050 as far as possible, the Commission has provided us with information on the capacity (power and heat) as well as the steam production by combined heating plants (CHPs) for all Member States in the relevant scenarios. Based on a comparison with historic data, the resulting capacity factors have been partially adjusted, based on the level of installed CHP capacity and the share of residential and industrial heat load, respectively, which we assume to remain constant over the next 20 years.

We consider two different types of load profiles:

- *Process heat demand* (in the industry), with a largely constant off take and an average capacity factor of approx. 65%, subject to limited seasonal variations and a difference between business and non-business hours;
- *Heat demand for space heating*, largely in the residential sector, with a typical hourly pattern for different types of days and the daily quantities driven by average ambient temperature.

16 For simplification, we consider the same combination of different rooftop installations for all countries.

17 Based on the equivalent power curves developed under the Trade Wind project; see "WP2.6 – Equivalent Wind Power Curves" (http://www.trade-wind.eu/index.php?id=9)

For the space heating profiles, we rely on the same set of historic meteorological data as previously described for wind and solar power. As such, the resulting heat profiles are fully consistent with the profiles used for RES-E production and furthermore reflect the considerable volatility of heat demand.

Real-Time System Operation and Operating Reserves

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 system operation model for scheduling generation and operating reserves in each region exploits the diversity of demand and renewable outputs across Europe to minimize operating costs while significantly enhancing the ability of the system to accommodate the output of variable renewable generation sources.

The stochastic modelling of intermittent 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 scheduling of reserves imposes further constraints on system operation for the following reasons. Reserve scheduling causes generation output deviations from the optimal generation schedule in order to provide sufficient flexibility for generation output to either be increased or decreased in response to variations in demand and/or supply. The operating characteristics of reserve generation introduce further constraints including reducing the generation capacity available to supply demand and imposing limits on the lowest output to be delivered from flexible generation. The first effect can lead to requirements for greater generation capacity within the system either within each region or via interconnecting transmission. The second effect can lead to increased curtailment of variable renewable generation as the system must maintain adequate reserves, which will require flexible plant to be readily dispatchable. Where reserve generation is constrained by minimum stable operating limits, this can displace renewable generation unless sufficient transmission capacity is available to facilitate exports outside the node or sufficient storage is available within the node.

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.

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

- Automatically activated frequency containment and frequency restoration reserves[18] (“response”) that can be activated in a timeframe from several seconds to a few minutes;
- Manually activated frequency restoration reserves (“Fast reserves”) with an activation time of less than 30 minutes; and
- Replacement reserves with an activation time of several hours ("Back up") that are used to mitigate unforeseen imbalances between demand and supply over longer time horizons.

The initial reserve requirements have been determined based on existing operating practices, i.e. the volumes of different ancillary services that are currently procured and held by TSOs in each country. For future years, the basic reserve requirements are endogenously adjusted on an hourly basis, based on the simulated output variable RES-E in each hour. For each reserve type, the total volume is increased, if necessary, such as to cover the largest possible variation over the corresponding time horizon, using the persistence of short-term fluctuations.

On the supply side, the availability of different types of ancillary services varies by technology and depends on the underlying assumptions on ramp rates, start-up times and the ability for proiding frequency response and regulation. Moreover, a conservative approach has been followed by not including the contribution of any frequency sensitive loads towards frequency regulation (for example smart refrigerators). Moreover, the model allows sharing the different types of ancillary reserves between different regions across interconnectors. This is based on the overall co-optimisation of energy and reserves for each hour and ensures that a certain share of interconnector capacity may have to be reserved for reliability purposes.

At present, European TSOs generally procure ancillary services on a national basis. But there are also several examples of regional integration, for instance in the Nordic region and Central Europe. Moreover, the regional exchange of reserves and balancing services represents a core objective of the European Framework Guidelines for Electricity Balancing, which furthermore stipulate a set of different timelines for the different processes. In line with these developments and requirements, the simulations in this study are based on the assumption that reserves are regionally shared between different countries and regions. More specifically, back up capacity can be freel shared between all countries, subject to the availability of sufficient interconnector capacity. In addition, we consider the following regions, within which response and fast reserves are shared on a regional basis:

- Nordic countries (NO, SE, FI, DK-East);
- Baltic (EE, LV, LT);
- Central Western Europe (DK-West, DE, NL, BE, LUX, FR, CH, AT);
- Central Eastern Europe (PL, SK, CZ, HU);
- GB + IE
- Iberia (ES + PT);
- Italy; and
- South Eastern Europe (all other countries).

18 Although these two products have different technical characteristics, we have combined them to simplify the analysis.

2.2 Transmission Modelling

For the modelling of the transmission grids, we have developed a simplified grid model that is based on a zonal transport model with a total of 74 individual nodes and approx. 165 existing and potential (inter-) connections between these nodes. As illustrated by Figure 22 this grid model covers all Member States that are physically part of the interconnected electricity market within the EU[19]. By also including Norway, Switzerland, Albania and the remaining members of ENTSO-E in South-Eastern Europe, the model provides for a comprehensive coverage of the continental European grid.

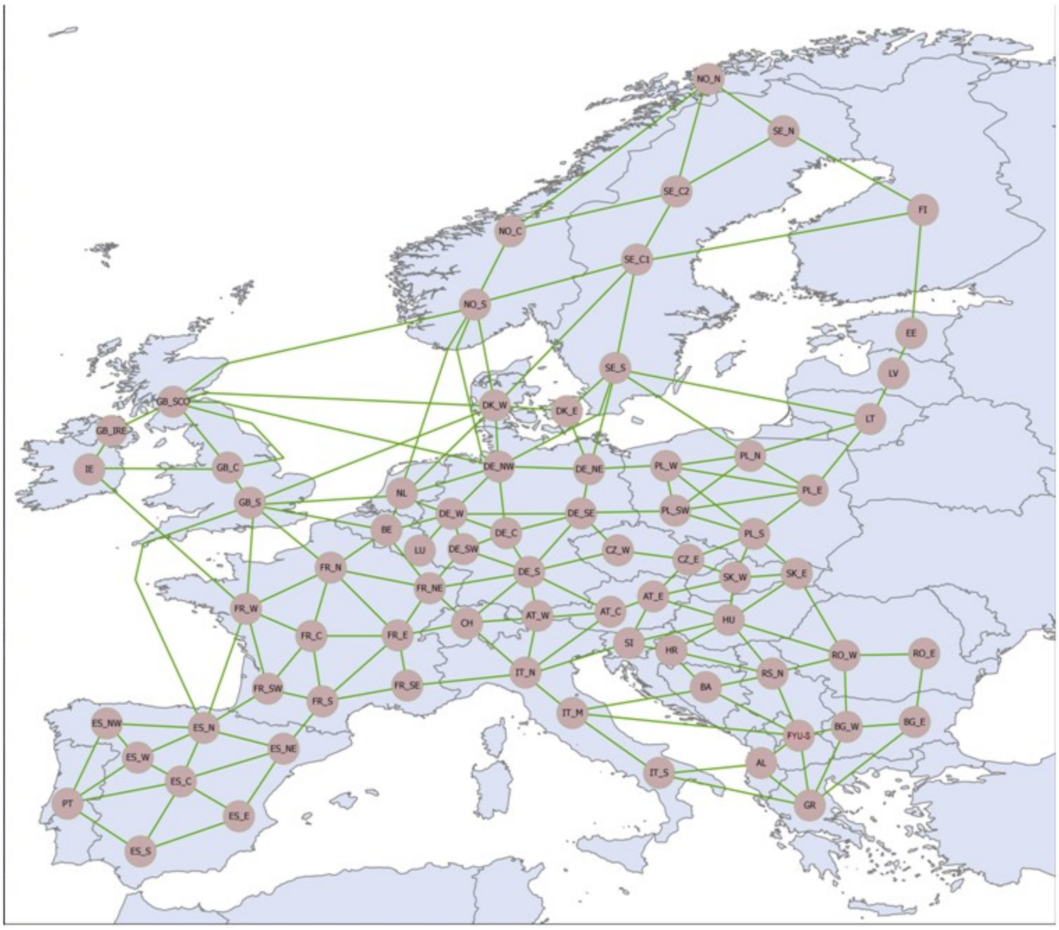


Figure 22 Topology of Regional Transmission Model

In many cases, the networks of individual Member States are represented by two or more network zones, in order to better reflect internal congestion and the potential need for transmission expansion especially within larger countries[20].

Similar to the approach chosen by ENTSO-E for the 10-Year Network Development Plan, the capacity of each existing (inter-) connection is determined by the Grid Transfer Capability (GTC). The GTC specifies the ability of the grid to transport electricity across a given boundary, i. e. from one area (a country or an area within a country) to another. The use of GTCs effectively corresponds to the notion of transfer capacities, which are commonly used for determining the transmission capacity available for cross-

19 Including Croatia but excluding Cyprus and Malta

20 In contrast, we have partially aggregated the countries in the Southern part of former Yugoslavia, due to the small size of the corresponding power systems and a limited expected impact on the development of the transmission grids at the European level.

border trading in the European electricity markets. The corresponding values have been derived from the NTC[21] values published by the European TSOs, the incremental GTC's specified in the latest version of the 10-Year Network Development Plan (from July 2012) and from our own analysis of the existing and planned transmission infrastructure.

Besides the GTC of current and planned infrastructure, each (inter-) connection is characterized by the specific costs of capacity expansion, in terms of €/MW/km. The corresponding values are based on typical values, which have also been used by various other studies and which reflect the fundamental difference between AC and DC lines as well as topography; see Table 12.

Table 12 Basic Assumptions for Cost of Transmission Expansion

Technology	Unit	Costs
Overhead line (AC), normal conditions[a]	M€/MW/km	0.500
Overhead line (DC), normal conditions[a]	M€/MW/km	0.150
Submarine cable (DC)	M€/MW/km	1.5
Additional costs for rough terrain		35%
Additional costs for extreme conditions		75%
Discount for use of guyed towers		-35%
Converter station (AC/DC)	M€/MW	0.075

[a] – Including cost of switchgear
Source: DNV GL assumptions

2.3 Distribution Modelling

2.3.1 Distribution Models used for the Analysis

The distribution analysis serves to understand the impact of distributed generation and load growth (e.g. electrification of heat and transport sectors) on future distribution network operation and investment, to quantify the benefits of alternative distribution network control approaches, including active network management, demand response and application of smart grid network technologies, and to assess the cost and performance characteristics of different distribution network design strategies, including optimisation of the number of voltage levels, equipment design approaches etc.

Apart from the analysis of technical and operational measures, the primary objective of the distribution analysis is to estimate the need and cost for distribution expansion in different scenarios. In addition, this analysis will also reveal whether and to which extent the use of distributed generation and their treatment in the market can help to avoid costs linked to additional grid build out at the distribution level, whilst the corresponding effects on the transmission level will be captured by the generation and transmission model discussed in Sections 2.1 and 2.2 above. In both cases, our analysis will not address the principal presence of such effects but also help to quantify their impact.

As illustrated by Figure 23 the overall approach taken can be summarised as follows:

- In a first step, we have collected information on typical network design policies and standards in different Member States and carried out a statistical analysis of population density (as a proxy for load density) in each country (see Section 2.3.2 below for further details);
- This information is then used to create a set of typical networks that can be expected to be representative of the real situation in each of the Member States; and

21 Net Transfer Capacity

- These representative networks then provide the basis for the detailed distribution analysis and the determination of network reinforcement costs.

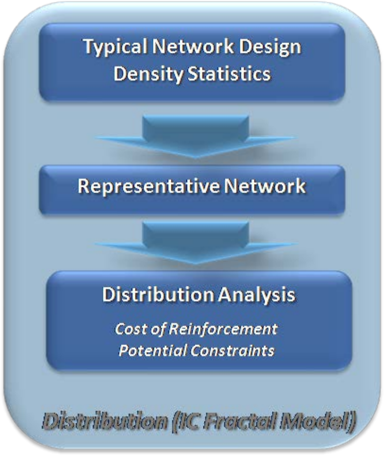


Figure 23   General Approach for Distribution Analysis

Source: Imperial College

Figure 24 below shows another view of our approach: for a given scenario, load characteristics of four network user categories, associated with individual local authority areas are specified for each year across the period: (i) domestic, commercial and industrial consumers, (ii) electric vehicles, (iii) heat pumps and (iv) various types of distributed generation. All users are allocated to distribution sites in relation to the scenario considered. In addition, the overall approach supports to different operation paradigms (e.g. business as usual or 'smart'). The chosen paradigm as well as the level of responsiveness of demand assumed will then drive peak network demand and the corresponding levels of network reinforcement.

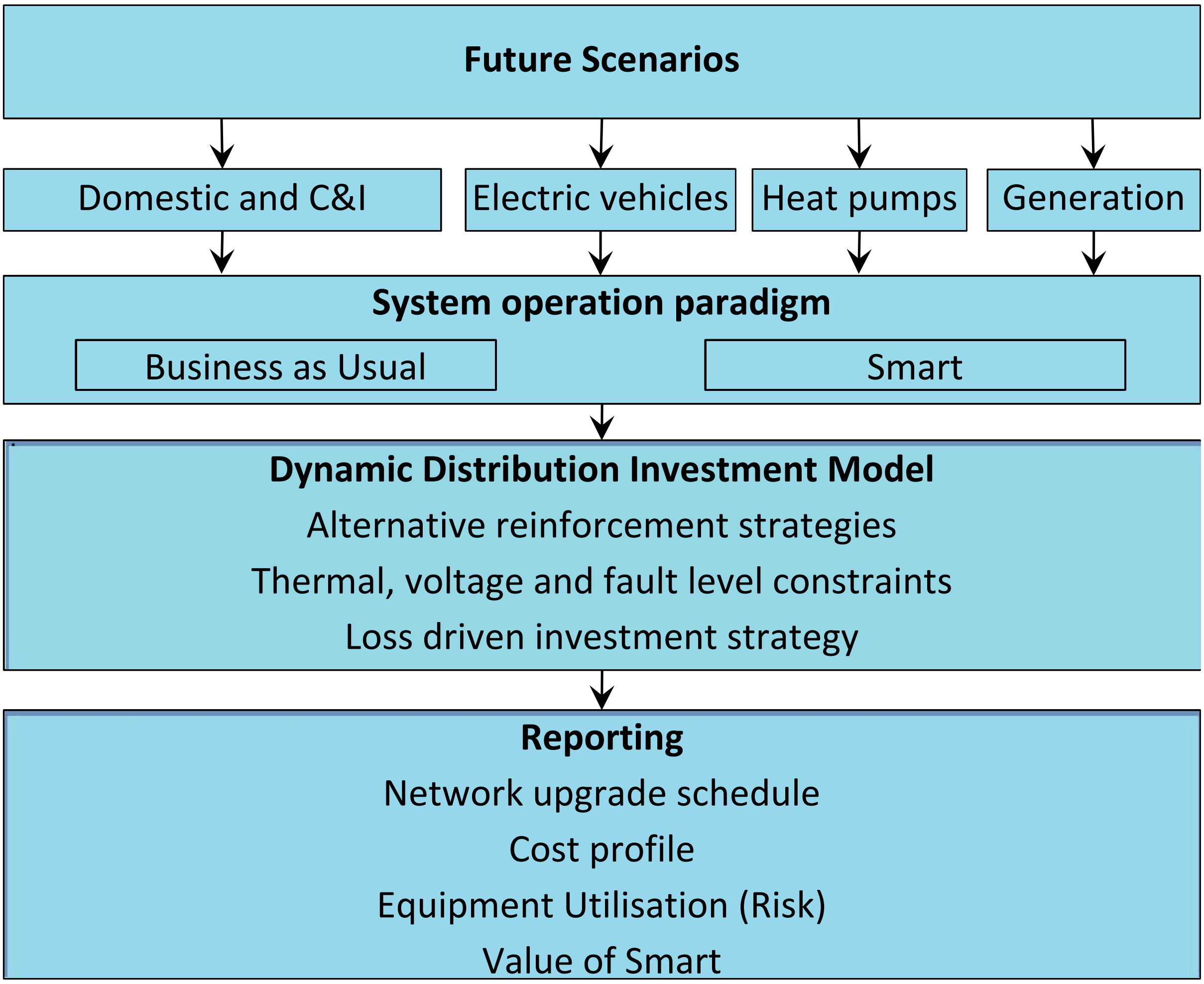


Figure 24 Modelling approach for distribution modelling

Source: Imperial College

The Dynamic Distribution Investment Model (DDIM) tests whether thermal, voltage and/or fault level constraints are violated and proposes appropriate upgrades of assets based on a defined reinforcement strategy. Finally, the model produces reports on network upgrades identified, an associated schedule, together with equipment utilisation profiles. This also includes modelling of alternative network reinforcement and design strategies, quantifying the potential benefits of alternative mitigation measures such as demand response and other active network management techniques.

The developed modelling approach includes three distribution network models:

- Low Voltage (LV) network model;
- Medium Voltage (MV); and
- High Voltage (HV) networks.

The LV network model is based on representative fractal networks with the parameters that represent the key characteristics of typical LV networks (0.4 kV) supplied from individual distribution transformers. The MV network model contains feeders with typical voltages of approx. 6 – 36 kV starting from secondary busbars in the HV/MV substations and finishing with distribution substations. The HV network finally contains assets from the Grid Supply Point, i.e. the connection to transmission (220 – 400 kV), down to HV/MV transformers in primary substations[22].

The distribution model does not explicitly consider the structure of European transmission networks, which are covered by the transmission model (see Section 2.2 above), and vice versa. In line with the typical structure of European electricity networks, the interface between the transmission and distribution models are represented by so-called Grid Supply Point, i.e. substations where high voltage distribution networks are connected to the transmission grid.

One key component of the Dynamic Distribution Investment Model is the Generic Distribution System (GDS). The GDS uses representative distribution networks to capture key network parameters associated with particular design and area specific features (e.g. urban or rural). Although the GDS model in principle includes all voltage levels, starting at the Grid Supply Point (connection with the sub-/transmission network), it is mostly suitable for analysis of networks operating at Medium Voltage level and above. In order to simplify the application and analysis, only four voltage levels are considered. As illustrated by Figure 25, these may for instance include 0.4kV, 11kV, 33kV, and 132kV. Due to the diversity of European distribution networks, however, these main network levels are adjusted to the prevailing voltage levels in different countries.

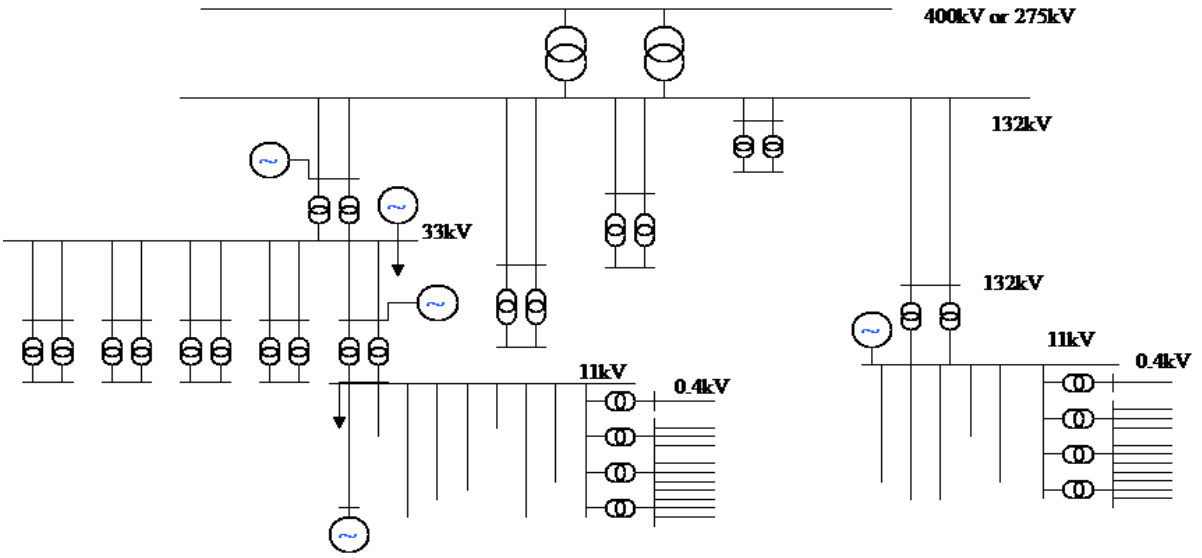


Figure 25 Example of schematic network diagram in GDS

The GDS platform uses the concept of characteristics days in order to perform annual analysis: typical daily profiles of weekdays, Saturdays and Sundays for winter, summer, and autumn/spring seasons are used, as presented in Figure 26. Similarly, we use typical generation profiles, based on the approach described in Chapter 0 above. Based on these inputs, the GDS model performs an annual analysis through power flow and optimal power flow calculation. Results of the analysis are detailed information of many aspects of the network including losses, power flows, and voltage drops.

22 Please note that the definition of high voltage networks varies between Member States. Whilst these are understood to comprise networks with voltages of 72 to 150 kV in many countries, these network levels are understood to be part of (sub-) transmission networks in other countries. Similarly, some countries use a single voltage level at the MV level, whereas other are characterised by two separate voltage levels in this range (e.g. 11 and 33 kV), with the upper class being defined as HV.

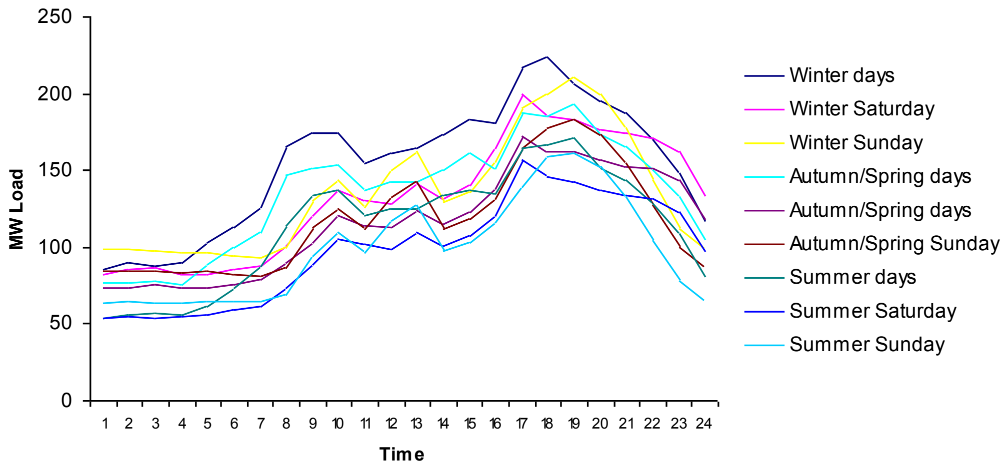


Figure 26 Typical days load profiles for the GDS model

The second key element of the distribution analysis is the Fractal LV & HV Distribution Networks Model (Fractal Model). The Fractal Model can create representative low-voltage (LV) and high-voltage (HV) distribution networks that capture statistical properties of typical network topologies that range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks represent those of real distribution networks of similar topologies, for instance with regards to the number and type of consumers and load density, ratings of feeders and transformers used, associated network lengths and costs, etc.

Due to the lack of detailed information and the large degree of diversity in distribution network planning and design, it was impossible to perform a detailed assessment of the existing distribution networks in different European countries within this project. Nevertheless, experience has shown that it is possible to represent real networks through a limited number of typical networks with statistically similar network configurations. This approach allows for a number of design policies to be tested on a network with the same statistical properties as the network of interest. Moreover, any conclusions reached are applicable to other areas with similar characteristics.

For this purpose, we rely on a limited number of typical representative LV networks. For illustration, Figure 27 shows three basic examples of urban, semi-urban / semi-rural, and rural LV networks. Using these typical networks, many statistically similar consumer layouts can be generated and the corresponding distribution networks will have statistically similar characteristics.

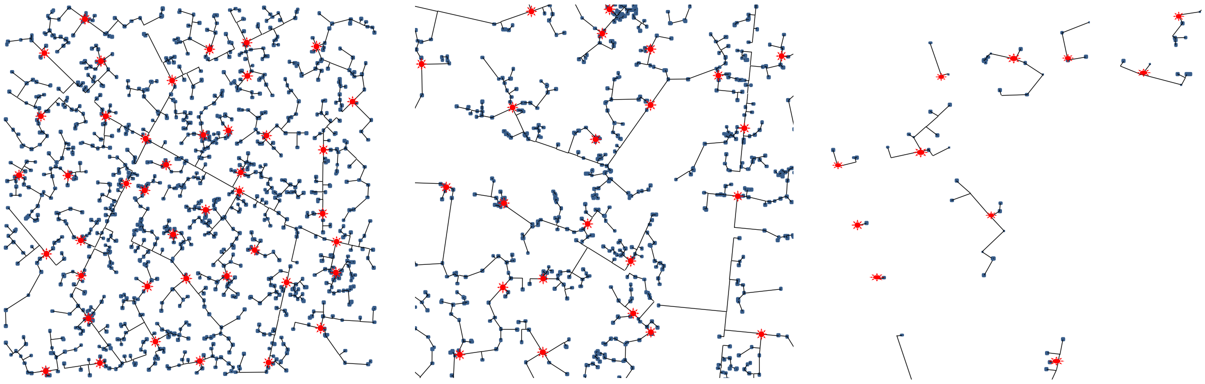


Figure 27 Example of LV representative distribution networks urban, semi-urban/rural, and rural

Note: The blue dots are LV consumers and the red dots are distribution transformers.

2.3.2 Distribution Network Analysis and Estimation of Reinforcement Needs

As mentioned, European distribution networks are characterised by very different planning and design standards. Moreover, for most countries, there is very limited information publicly available on the actual design of existing networks, which would allow for a highly detailed analysis. To cope with these issues, we have used a combination of a statistical analysis of the distribution supply areas in each Member State, on the one side, and the application of representative LV networks in the Fractal Model, on the other hand.

The overall approach can be summarised as follows:

- In a first step, we collected information on population density and land use for close to 100,000 administrative units (municipalities, districts, provinces etc.)[23] in the EU-27;
- In a second step, the administrative areas were clustered into different population classes in each country, and mapped against a limited number of representative LV networks; and
- In a third step, the design parameters of the representative LV networks in a given country were adjusted such that the sum of the individual networks corresponds to the overall size and structure of the distribution networks in that country; and
- Finally, we assigned a set of generation and load profiles to different network classes, based on the assumed load and penetration of decentralised generation in each country.

As mentioned above, the first two steps were based on a comprehensive data set for close to 100,000 administrative units in the EU-27[24]. The administrative areas in a given country were then grouped into different density classes, which can be expected to represent different types of distribution networks in practice. For illustration, Table 13 shows an example from Germany. More specifically, the table shows how approx. 3,800 municipalities (out of more than 11,000) in three of the seven transmission zones used in the transmission model (see Chapter 2.2 above) can be grouped into five different density classes. Not surprisingly, this table reveals major differences, with a large share of scarcely populated areas in Northern Germany, whilst most of the population lives in more densely populated areas in the

23 The level of detail varies by country, subject to the quality of publicly available data.

24 The corresponding data has been collected from Eurostat, national statistical offices and other sources.

areas DE_S and DE_W. Consequently, the share of rural and semi-rural areas is much higher in the first groups, whilst the latter comprises of a much higher share of urban and semi-urban areas.[25]

Table 13 Example - mapping of local areas by density classes

Population density	Parameter	DE_NE	DE_NW	DE_S	DE_W
0 - 50	Number of regions	863	698	255	1
0 - 50	Aggregate area (km2)	38.831	15.147	11.354	95
0 - 50	Aggregate population	1.049.620	502.504	433.683	4.116
50 - 100	Number of regions	173	657	1.024	24
50 - 100	Aggregate area (km2)	8.809	18.238	36.755	3.325
50 - 100	Aggregate population	615.450	1.335.715	2.740.615	254.801
100 - 250	Number of regions	119	488	1.065	148
100 - 250	Aggregate area (km2)	6.036	19.102	33.789	13.006
100 - 250	Aggregate population	919.700	2.956.528	5.239.721	2.181.353
250 - 1000	Number of regions	52	249	712	166
250 - 1000	Aggregate area (km2)	2.369	8.144	18.214	12.667
250 - 1000	Aggregate population	1.149.657	3.598.678	8.140.647	6.275.895
1000 - 10000	Number of regions	12	36	101	57
1000 - 10000	Aggregate area (km2)	1.458	2.612	3.647	4.999
1000 - 10000	Aggregate population	4.127.820	4.642.162	6.737.910	9.128.989

Using the number of different network classes and assumptions on their typical design (such as network length, number of connections or installed transformation capacity per km^2), we have then derived an estimate of the overall distribution infrastructure in a given country. This information was then compared against available evidence from each country, in order calibrate the resulting assumptions.

Using these network classes developed, the main part of the distribution analysis is related to the determination of necessary network reinforcement costs. This analysis is based on the use of the two models described above and derives an estimated of the required measures and cost for each of the different network classes. By aggregating the reinforcement costs across the number of size of all network classes, it is possible to determine the total distribution reinforcement costs in a given country (see Figure 28).

25 Please note that the individual administrative units cannot be directly equated to different networks. In fact, most administrative units cover different types of distribution supply areas themselves. For instance in rural areas, there will typically be smaller parts of the network with a higher population density. Similarly, even larger towns will usually comprise of some areas with much lower load density, such as in parks or the areas outside the inner city.

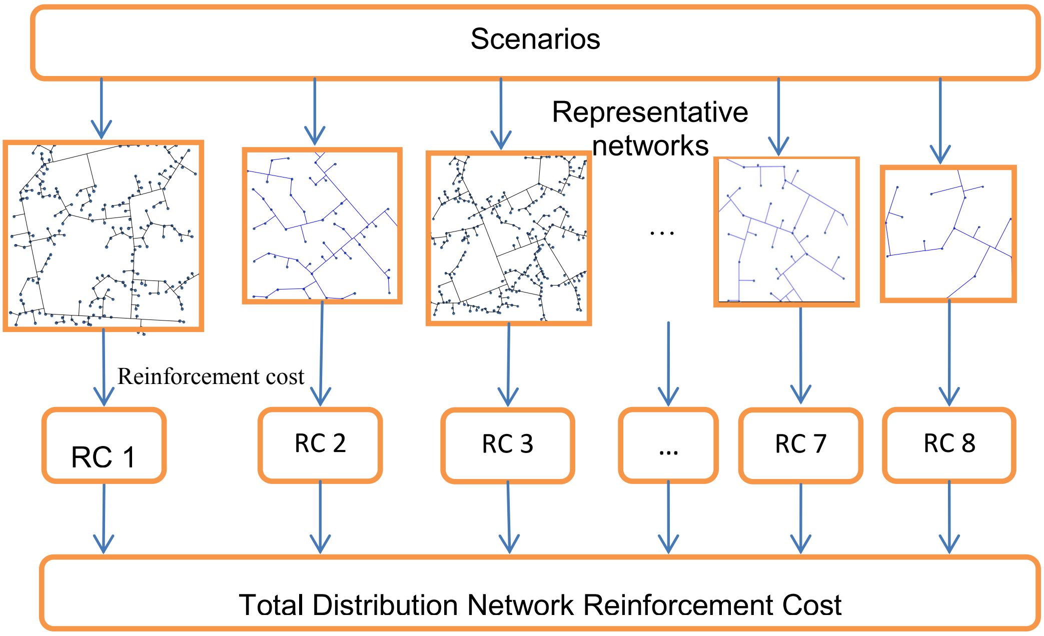


Figure 28 Representative Fractal networks approach to estimate distribution reinforcement cost (RC)

2.3.3 Specific Assumptions for Distribution Analysis

Connection Level of Decentralised Generation

In Chapter 3 below we have summarised our assumptions regarding the development of generation, demand etc. Whilst these assumptions are sufficiently detailed for the generation and transmission, it is necessary to take further assumptions on the connection level of decentralised generation for the distribution analysis. More specifically, the connection of decentralised generation to different voltage levels will impact the ability of the distribution network to accommodate the corresponding power and energy from DG and hence the need for network expansion or similar measures.

Due to the limited penetration of RES-E in most European countries today, we have used information from countries which have already achieved a sizeable volume of relevant RES-E technologies. More specifically, Table 14 provides an overview of the connection level of biomass, wind and solar power plants in Finland, Germany and Spain. This summary reveals significant differences between different countries both for biomass and wind power plants, whilst detailed data on solar PV are available for Germany only.

Table 14 Connection level of selected RES-E technologies in Finland, Germany and Spain

Connection level	**Biomass**		**Solar PV**	**Wind**	
	Finland[a]	Germany[b]	Germany[b]	Germany[b]	Spain[c]
Transmission	~ 55%	1%	-	5%	~ 60%
High voltage (HV)	~ 35%	13%	3%	46%	~ 35%
Medium voltage (HV)	~ 10%	76%	26%	49%	< 5%
Low voltage (LV)	-	*10%*	*71%*	-	

[a] – Based on size distribution; [b] – Based on 2010 RES-E statistics; [c] – DNV GL estimate

With regards to biomass plants, we note a remarkable difference between Finland and Germany. Whilst some 90% of total capacity in Finland is connected to high voltage and transmission networks but about 10% to distribution networks only, the ratio is almost the opposite in Germany. In this context, it is worth noting that the Finnish numbers include a considerable number of large plants fired by peat or waste products from the paper and pulp industry. Consequently, it appears reasonable to assume that the share of plants connected to transmission and high voltage networks in Finland may be higher than what in other countries with an increased penetration of biomass plants. Conversely, the German situation has been influenced by the subsidy scheme under the Renewable Energies Act which has provided strong incentives to build smaller plants.

With regards to solar PV, German statistics show that small roof-top installations on private buildings represent about 70% of the total. Most of the remaining capacity, which covers roof-top installations on larger public and commercial buildings as well as ground mounted facilities, is connected to medium-voltage networks, whilst less than 3% of total capacity is connected to HV networks. We principally assume that these numbers may be reasonably representative also for other European countries, although the share of large installations on public and commercial buildings and ground mounted installations may be larger especially in Southern Europe.

For wind power, Table 14 shows a considerable difference between Germany and Spain, with virtually all wind power plants connected to distribution networks in Germany, whereas 60% of the installed capacity is directly connected to the transmission grid in Spain. This difference again reveals the specific situation of Germany, with a large number of small turbines and/or wind farms, as opposed to the construction of larger wind farms in Spain. Based on our experience, the Spanish case can be considered as more representative for other countries, also with a view to the increasing use of larger turbines. Nevertheless, the size of wind farms is also influenced by population density and other factors, such that the situation in different countries may be different. We have therefore applied different assumptions for scenarios with a more 'centralised' structure of RES-E technologies and scenarios that are specifically looking at decentralised generation.

Table 15 summarises our resulting assumptions on the distribution of different types of DG-RES to different voltage levels. In addition, Table 15 also differentiates between rural, suburban and urban areas for medium and low voltage networks.

Table 15 Assumed distribution of DG-RES to different voltage levels

Network Type	**Wind (onshore)**		**Solar PV**	**Biomass**	**Run-of-River**
	Central scenarios.	DG scenarios		(Incl. CHP)[d]	
Transmission	60%	50%	0%	30%	40%
High voltage (1xx kV)	30% (all rural)	20% (all rural)	8% (all rural)	30%	35%
HV/MV [a]	5%	10%	2%		10%
MV (10 – 36 kV)	5%	20%	25%	40%/30% [c]	10%
Rural	*100%*	*100%*	*79%*	*80%*	
Suburban			*19%*	*20%*	
Urban			*2%*		
MV/LV [b]	0%	0%	5%	0%	5%
LV (0.4 kV)	0%	0%	60%	0% / 10% [c]	0%
Rural			*79%*		
Suburban			*19%*		
Urban			*2%*		

(a) - Same distribution rural etc. as for MV; (b) - Same distribution rural etc. as for LV;
(c) - in normal / DG scenario; (d) – Assume that decentralised CHP covered by biomass

Network Reinforcement Cost

Table 16 provides an overview of our assumptions on the cost of new distribution lines and cables, which we are using for our analysis. In most cases, Table 16 shows a range rather than a single number, with some sometimes fairly wide variations within the same group of assets. Apart from national cost differences, these variations can mainly be explained by the use of different types of equipment, their rating, and other environmental factors, such as population density. For instance, whilst an underground cable can be put into the ground at limited cost in open areas that are not used for agriculture, cost are much higher in urban and city areas where cables have to be laid deep below paved roads and other infrastructure.

Table 16 Assumed network reinforcement costs (€/m) for cables and overhead lines

Network / Voltage Level (kV)		Overhead [(a)]	Cable
High voltage (HV)	110 – 123 kV	100 - 260	400 – 1,400
Medium voltage (HV)	30 – 36 kV	50	350
	10 – 20 kV	30 – 50	75 – 140
Low voltage (LV)	0.4 kV	15 - 40	40 – 135

(a) – Per circuit
Source: Imperial College / DNV GL estimates

Table 17 shows a similar set of assumptions for transformers and substations. Again, the variations in each group reflect both differences between different countries as well as the use of transformers with different ratings.

Table 17 Assumed network reinforcement costs for transformers and switchgear (k€)

Network Level	Secondary Voltage / Assets	Cost
EHV[(1)] / HV	Transformer + switchgear	2,000 – 3,500
HV / LV	30 – 36 kV (transf. + switchgear)	920 – 1,600
	10 - 20 kV (transf. + switchgear)	350 – 1,200
MV / LV	Transformer only	10 – 22
	Station (incl. transf.)	30 – 40

[(1)] – Extra high voltage (220 – 380 kV)
Source: Imperial College / DNV GL estimates

2.4 Simplifications and Limitations of the Modelling Framework

The previous sections have described the structure and methodology of the different models, which we have used for this study. Although we have applied a number of sophisticated models, we have had use a number of simplifications, for instance due to the vast amount of data that was used for this analysis. In addition, one has to consider that any model-based analysis is subject to certain limitations. Apart from the design and capabilities of each individual model, other limitations may stem from the necessary interaction between different models. Last but not least, certain limitations also stem from the input assumptions used for this analysis, for instance due to limited availability of detailed data on European networks.

In this Section, we therefore briefly comment on simplifications, interface and data issues, which have to be considered when interpreting the results in the latter parts of this report. More specifically, it seems worth noting the following aspects:

- Methodological and interface issues of the market and network models;

- Use of simplified assumptions;
- Issues related to the use of PRIMES scenarios.

2.4.1 Methodological and interface issues of the market and network models

Use of different models for capacity expansion and daily market operations

As explained in Section 2.1 above we have applied two different modelling tools for long-term generation expansion, on the one side, and the optimisation of the transmission infrastructure and the simulation of daily market operations, on the other side. Using two different models allowed capturing certain key characteristics, but also required several simplifications in other areas:

- The use of PLEXOS for long-term generation expansion allowed considering the entire time horizon of the study, as well as the future outlook until the year 2050. This principally ensures investment decisions that are consistent with the development of market prices over time. However, due to the long time horizon and the relatively high level of detail at which the European generation and transmission infrastructure was represented, we did not consider all 8,760 h of each year.
- Conversely, DSIM provides for a very detailed representation of the operational challenges in each hour of the year. But in return, it was necessary to limit the simulation horizon to individual years, and to a much higher level of aggregation of the generation park than in PLEXOS.

The use of two different models thus leads to some limitations. To start with, consideration of isolated years in DSIM may lead to situations where transmission or back up capacity is added at an early stage but not in later years. Although the overall trend can be expected to remain unchanged, this limitation should be kept in mind when interpreting minor changes in infrastructure requirements in Chapter 4.

Secondly, the detailed simulations in DSIM may result in a higher need for transmission and back up capacity than in PLEXOS. A higher level of interconnection helps to reduce volatility and thus is to the advantage of peaking and in particular back-up plants. Similarly, the much higher level of aggregation in DSIM effectively reduces the influence of different plant efficiencies. Although this may not change the overall generation dispatch, it will further reduce the volatility of hourly market prices and lead to a convergence of revenue streams for older (less efficient) and newer (more efficient) plants.

The market prices resulting from DSIM are not thus necessarily perfectly consistent with the investment decisions taken by PLEXOS. These limitations are especially important when analysing the profitability of generation, which may be under-estimated especially in case of new-built plants[26].

Limitations of cost-based unit commitment model

The market modelling framework presented in Section 2.1 above aims to minimise the total costs of meeting electricity demand, subject to a range of constraints. As described above, the model can minimise costs by choosing dispatch patterns, new generation investments, T&D and interconnection investments, and can also shed load.

The modelling framework employed provides an estimate of market prices resulting from a cost minimisation algorithm. Formally, these prices are calculated as the dual (or shadow price) on the

[26] Indeed, we have observed various cases where new plants were not immediately able to recover their full costs in the first year(s) of operation, especially in more remote regions, even if they were able to do so in later years.

demand constraints in the Generation and Transmission Investment and Operation Model (see Figure 19). In other words, these prices represent the marginal cost of fractionally increasing demand in any given hour. Although this approach to estimating power prices is widely used in power market modelling, the use of shadow prices to estimate power prices has significant limitations, and as such they can only be interpreted as a proximate measure of how prices will vary across scenarios.

The optimal dispatch of power generators does not simply depend on a comparison and ranking of installed plants' variable costs of operation. Optimising dispatch requires a complex optimisation of "unit commitment" patterns across a portfolio of generation plant. Discrete unit commitment decisions require, for instance, that the model decides whether to incur the fixed costs of starting up a generator.

Consider, for example, a 1,000MW CCGT with a start-up cost of €10/MW and a variable cost of production (once the unit is committed) of €50/MWh. In this case, to "commit" the unit, the model must incur fixed costs of start-up of €10 x 1,000MW = €10,000. This is a fixed cost that is incurred, irrespective of the plant's output. Suppose the model decides through its cost minimisation algorithm to dispatch this, and that to meet demand in the market, this plant is required to produce 750MW. Assume further that this plant is the marginal source of production in the market as a whole. That is, following a marginal increase or decrease in demand, the model would choose to vary this plant's output, e.g. upwards to 751MW or downwards to 749MW, thus increasing or decreasing costs by €50/MWh. Hence, the marginal cost of meeting demand, and hence modelled energy prices, would be €50/MWh.

In this example, the revenue earned by the plant would be €50 x 750MW = €37,500. In the absence of unit commitment costs, this revenue would precisely remunerate the variable operating costs of the marginal plant on the system, and so the modelled price would be "incentive compatible". However, this hypothetical plant's unit commitment costs mean this revenue would be insufficient to cover its total costs of operation (€50 x 750MW + €10,000). The effect of discrete unit commitment decisions therefore means that we would not necessarily expect our modelled prices to fully remunerate all costs, as would be the case in a market equilibrium.

Secondly, the assumption of a perfect market equilibrium may not always hold in reality. Especially during situations with tight margins, generators may be able to increase prices above variable costs, in order to earn additional margins and recover their fixed costs. To deal with this issue, the generation and market model presented in Section 2.1 above includes a feature that aims at representing such scarcity prices as the residual capacity margin becomes tighter. However, the corresponding methodology is obviously based on simplified assumptions, and the results are unlikely to exactly match pricing patterns observed in practice.

The market prices presented in Chapter 5.2, and hence modelled profitability of generators, should therefore only be interpreted as broadly illustrative of market trends and may not be fully representative of how prices will develop over time.

No consideration of local transmission

As explained in Sections 2.2 and 2.3 above, the analysis of network impacts and requirements makes use of two separate models, which each entail a number of simplifications.

The transmission model is based on a simplified representation of the European transmission systems. This simplified model aims at capturing the impact of congestion not only on national borders but also within individual countries. However, it is clear that the necessary simplifications and the use of a DC representation lead to substantial limitations. Among others, the scope of the transmission model has on purpose been limited to regional exchanges and constraints. Conversely, it does not aim at addressing possible congestion at a local level, for instance for connecting a large number of RES-E plants to the local transmission grid.

Secondly, the design of the distribution model principally provides for a fully realistic representation of existing distribution networks and the possible issues, which may arise when connecting additional supply or demand at different locations and voltage levels. However, as explained in Section 2.3 the European scale of the analysis has made it necessary to restrict the use of this tool to a range of typical networks. Despite the necessary degree of simplification and standardisation, the distribution model can be expected to provide for a robust view of the resulting effects and the necessary changes and investments at the distribution level. Nevertheless, it is clear that the results will not be 100% accurate.

Further limitations arise from the connection between the pan-European transmission model, on the one side, and the use of typical distribution networks, on the other hand. As explained in Section 2.2 the transmission model is based on different network zones, which are each represented by one single node. In contrast, the typical networks considered by the distribution model are deemed to be connected to the transmission network at a number of notional Grid Supply Points. Depending on the future development and expansion of the transmission network, the number, location and structure of these Grid Supply Points may principally change as well, but this is not explicitly modelled within either of the two models. This implies that the distribution analysis may either over- or under-estimate the need for network expansion mainly at the HV level.

2.4.2 Use of simplified assumptions

In the previous Section, we have already commented on the use of simplified assumptions, resulting for instance from the aggregation of generation technologies by type or the use of typical networks for the distribution analysis. With regards to the representation of conventional generation, arguably the most important simplifications relate to the assumption of standardised technical and commercial properties and the aggregation of all units of a given technology into a single plant in each network zone in the final market model. As explained, these simplifications lead to clear limitations, which have to be considered when interpreting the results of the quantitative analysis in this study.

It is furthermore important to consider further simplifications related to the representation and treatment of RES-E. Among others, these are related to the use of standardised assumptions for different RES-E technologies and the associated production patterns (compare Section 2.1.2.3 on p. 9 above). However, such simplifications appear inevitable when considering the regional scope of the study and the uncertainty related to the future development of smaller RES-E installations in the time horizon until the year 2030.

In addition, we have used standardised assumptions for the connection of DG-RES to different voltage levels. As explained in Section 0, the corresponding assumptions are mainly based on experience from a few selected countries. These standard assumptions may fail to account for other possible outcomes, for instance with regards to the size and connection level of solar PV facilities. A different distribution of DG-RES in terms of size and connection level may lead to different infrastructure needs and costs. We therefore specifically comment on this issue in Section 4.4 below.

Although the methodology applied for this study considers the situation in every single hour of a given year, it is important to note that we have not considered truly critical or extreme situations. All simulations have been carried out for a single set of hydro and RES production profiles, i.e. they do not consider the impact of dry years with limited availability of hydropower or exceptional situations with a prolonged period with minimal production available from wind and/or solar power, which may lead to an under-estimation of the requirements for back up capacity.

2.4.3 Issues related to the use of PRIMES scenarios

As explained in Chapter 3 below the different scenarios and sensitivities considered by this study are largely based on the analysis carried out in the PRIMES model for the Energy Roadmap 2050, which was published in December 2011.

Apart from consistency with other analytical work by or on behalf of the European Commission, this approach has had the main advantage that we had access to a fairly detailed set of data and assumptions, which are based on a consistent modelling framework. Among others, the corresponding work was based on broader macro-economic models, which should ensure consistency between the overall economic development, on the one hand, and the specific assumptions used for more detailed analysis of the European power systems, for instance with regards to demand or the evolution of CO_2 prices.

In contrast, the PRIMES model did only provide for a much more simplified representation of the physical constraints of the European power systems, for instance in terms of the need to hourly load and RES-E production profiles, or the impact of limited transmission capacities. Moreover, the development in recent years – especially the rapid cost digression of solar PV – implies that some of the cost assumptions used for the original analysis in the Energy Roadmap 2050 have been partially changed for the current analysis.

These aspects apply that the optimised expansion of different RES-E technologies in the Energy Roadmap 2050 may no be longer optimal from the perspective of the analysis carried out under this study. Consequently, some of the results presented below partially represent underlying changes in assumptions and the different focus of the models used for the original analysis and the current study. These differences should be taken into consideration when interpreting and comparing the results of the different scenarios and sensitivities, in particular with regards to infrastructure requirements and overall costs.

3 DESCRIPTION OF BASIC SCENARIOS AND SENSITIVITIES

3.1 Outline of Selected Scenarios and Variations

This study considers three main scenarios that are differentiated mainly by the future penetration of RES-E, i.e. an optimistic, middle and a pessimistic case. These main scenarios are directly based on the Energy Roadmap 2050 as follows:

1. **Optimistic Scenario (Scenario 1)**
   Based on Energy Roadmap 2050, 'High RES-E' scenario;
2. **Middle Scenario (Scenario 2)**
   Based on Energy Roadmap 2050, 'Diversified Supply Technologies' scenario; and
3. **Pessimistic Scenario (Scenario 3)**
   Based on Energy Roadmap 2050, 'Current Policy Initiatives' scenario.

As illustrated by Figure 29 below, these three scenarios mainly differ by the structure of electricity generation. Conversely, they are characterized by a very similar level of demand. At the same time, a comparison with other studies highlights the fact that there exists considerable uncertainty on the future development of load and energy efficiency. For this purpose, we furthermore consider the two variations of the scenario 1:

- **Sensitivity 1a: Optimistic scenario with high demand**
  Based on the consumption in the 'Reference Scenario' of the Energy Roadmap 2050, but with the same share of RES-E as in the High RES-E scenario; and
- **Sensitivity 1b: Optimistic scenario with high energy efficiency**
  Based on the consumption in the 'High Energy Efficiency' scenario of the Energy Roadmap 2050, but with the same share of RES-E as in the High RES-E scenario.

Figure 29 shows that the combination of the 3 main scenarios with the additional two variations covers a fairly broad range of different developments, including those considered by a variety of other studies[27]. Moreover, these scenarios specifically allow assessing the impact of different types and levels of RES-E, including in particular decentralised RES-E.

[27] With the notable exception of the Power Perspectives 2030 from the European Climate Foundation, which is characterized by ambitious assumptions on the penetration of electric heating and electric vehicles.

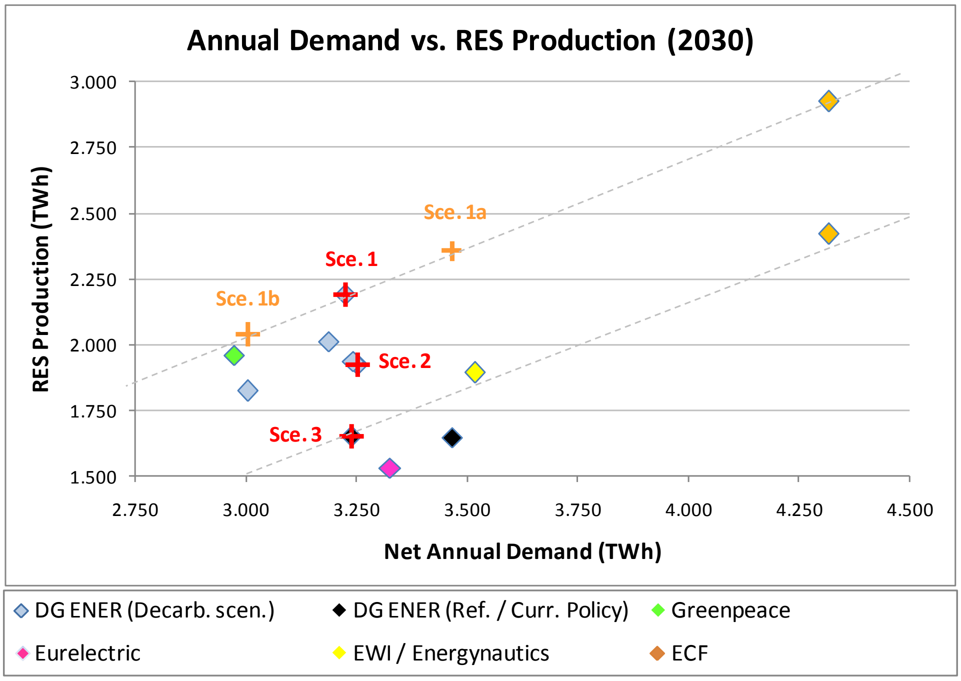


Figure 29 Overview of main scenarios and variations of scenario 1

Based on these assumptions, Figure 30 shows the evolution of final electricity demand in the period from 2010 to 2030 for all five scenarios[28]. Similar to Figure 29, this illustration clearly shows that the development of the three main scenarios is broadly comparable. Conversely, scenarios 1a and 1b are characterised by much higher and lower electricity consumption, respectively.

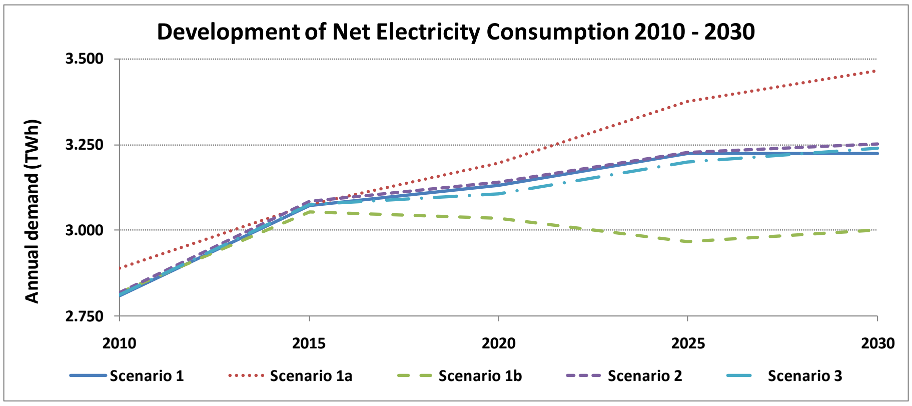


Figure 30 Development of final electricity demand in the individual scenarios

The scenarios in the Energy Roadmap 2050 are characterized by a limited share of solar energy in comparison with other studies; see for instance Figure 31. Against the background of this study, which specifically assesses the impact of decentralized RES-E on distribution networks, it appears desirable to increase the volume of solar energy (and other types of DG-RES) in some scenarios. For this reason, we have considered three additional scenarios with an increased share of DG that are based on the

28 PRIMES data is available for 5-year intervals only. The assumptions for the remaining years have therefore been determined by linear interpolation.

variations of Scenario 1. These additional variations are subsequently denoted as Scenarios 1-DG, 1a-DG and 1b-DG.

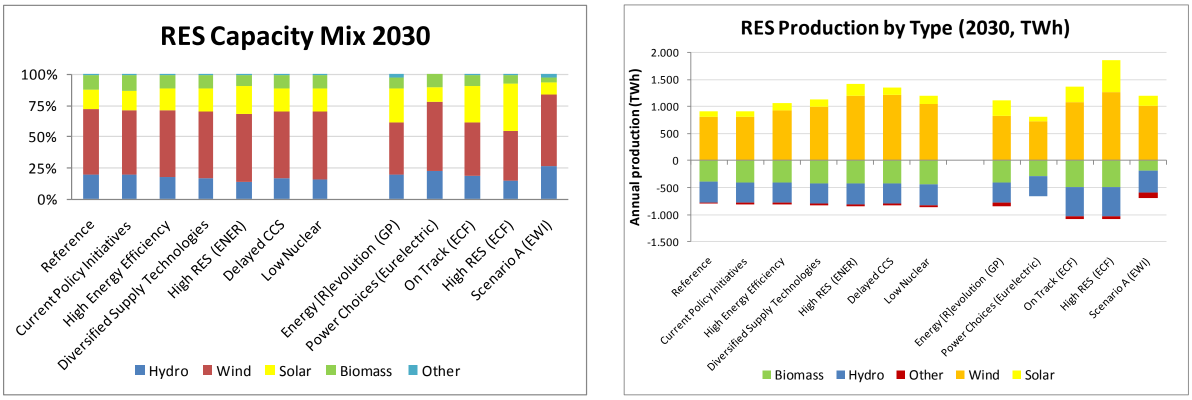


Figure 31 Share and distribution of RES-E in different studies and scenarios

Besides the development of RES-E, it is necessary to take assumptions on the future role of nuclear energy in each scenario. As agreed with the Commission, we use detailed assumptions from PRIMES (Energy Roadmap 2050) for the three main scenarios and the variations that have been built upon these scenarios..

Table 18 provides a summary of all main scenarios and variations, which we have analysed in this study. In addition to the three main scenarios, this includes the variations of Scenario 1, or a total of eight different cases.

Table 18 Summary of basic scenarios and variations

#	Scenario / Variation	Description	Additional variation
1	Optimistic Scenario	RM 2050 'High RES-E'	High share of decentralised generation (DG)
1a	Optimistic scenario with high demand	Demand: RM 2050 'Reference'; RES-E: Same share as scenario 1; Nuclear: RM 2050 'Energy Efficiency'	
1b	Optimistic scenario with high energy efficiency	Demand: RM 2050 'Energy Efficiency'; RES-E: Same share as scenario 1; Nuclear: RM 2050 'Reference'	
2	Middle Scenario	RM 2050 'Diversified supply technologies'	-
3	Pessimistic Scenario	RM 2050 'Current policy initiatives'	-

As mentioned above, the different scenarios and variations have largely been modelled based on the Energy Roadmap 2050. More specifically, the main scenarios reflect the corresponding assumptions on the development of demand, RES-E, nuclear energy, cogeneration as well as fuel and CO_2 prices. With regards to demand and generation, this includes the development and spatial distribution of capacity and consumption / production. Conversely, the development and use of other thermal power plants (i.e. coal-fired plants, CCGTs and OCGTs as a proxy for back-up plants) have been endogenously derived by the generation expansion and the transmission & market model. Similarly, it is important to note that the latter model has also been used to optimise the expansion of European transmission grids such that the resulting values are also different from the Energy Roadmap 2050.

In the following Section, we briefly present the generation structure in each of the eight different scenarios and variations and explain the underlying assumptions on the use of different RES-E technologies. Section 3.4 gives an outline of some additional sensitivities. Finally, we present our assumptions on fuel and CO_2 prices in Section 3.5.

3.2 Brief Description of Individual Scenarios

3.2.1 Scenario 1 (Optimistic Scenario)

Scenario 1 is based on the 'High-RES-E' scenario from the Energy Roadmap 2050. Consequently, all assumptions on the development of final electricity demand, nuclear power and RES-E are directly taken from PRIMES. As illustrated in Figure 32 Scenario 1 is characterised by limited demand growth and a declining contribution by nuclear power (approx. -1/3). Due to the significant growth of RES-E, however, gross production by low carbon technologies (i.e. nuclear power and RES-E) is equivalent to 86% of final demand in 2030, with RES-E alone accounting for 68% of final electricity demand. In addition, Figure 32 also shows that decentralised generation from onshore wind, solar PV and biomass accounts for some 560 TWh[29], or about one quarter of total production by RES-E.

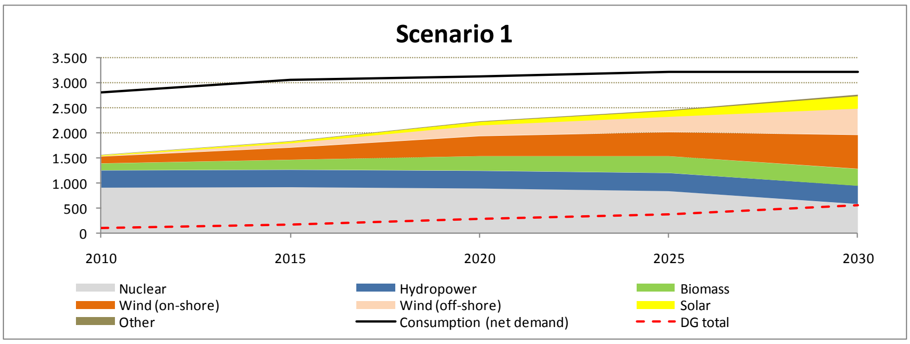


Figure 32 Demand vs. production from nuclear energy and RES-E in Scenario 1 (in TWh)

To complement this information, Figure 33 shows the development of the generation structure in terms of installed capacity. In total, installed capacity of RES-E grows from less than 250 GW in 2010 to nearly 900 GW in 2030. Due to the limited capacity factors of solar PV and onshore wind, DG represents about one third of total RES-E capacity or close to 300 GW, i.e. a significantly higher share than of actual production.

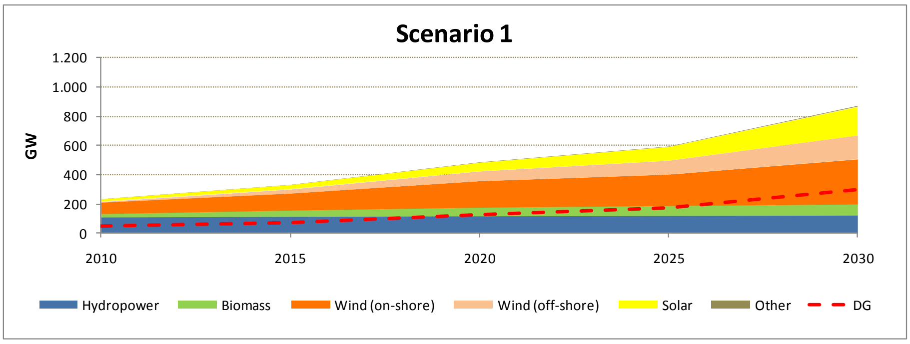


Figure 33 Installed RES-E capacity in Scenario 1

In addition to the main scenario, we consider a variation with a larger contribution by DG (Scenario 1-DG). More specifically, we take the following assumptions:

- First, we assume that the development of offshore wind is delayed by five years compared to the main scenario. For example, whilst the main scenario assumes 91 GW of offshore wind power to be

29 Please see Chapter 2.3.3 for assumptions on the share of DG for each of these technologies

installed in 2025, we assume that this level will be reached in 2030 only. Similarly, the original contribution of offshore wind in the years 2015 and 2020 is now only reached in the years 2020 and 2025, respectively.

- Secondly, we assume that the cost of solar PV will continue to decline at a much higher pace than in the original scenario and that solar PV increasingly becomes competitive against end-user prices. Against this background, we assume that the penetration of solar PV grows much faster than in the original scenario and is able to offset the reduced contribution by offshore wind.
- Thirdly, we assume an increasing penetration of small decentralised cogeneration units, such as small gas motors. More specifically, we assume that the total electricity supply from such small decentralised units is equivalent to 50% of the volume of electricity produced as a by-product for the supply of district heating to the residential sector in 2030 or some 65 TWh.

The combined effect of these developments is shown in Figure 34. In comparison to the original scenario, we now observe a much smaller contribution by offshore wind until 2030, whilst production by solar PV grows accordingly. At the same time, the share of electricity produced by DG increases to some 750 TWh or about 38% of total production by RES-E[30].

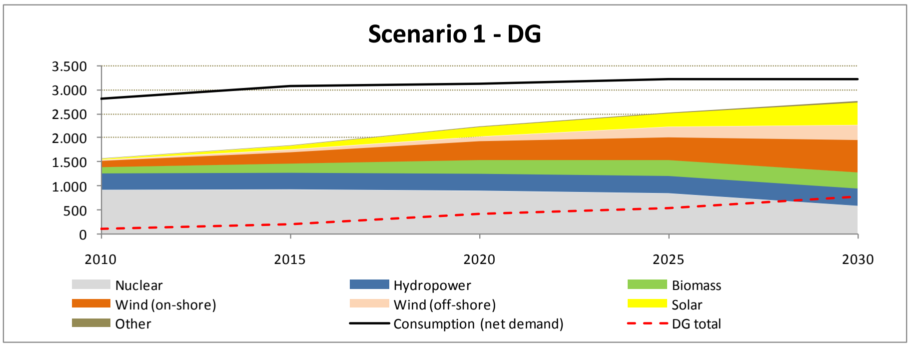


Figure 34 Demand vs. production from nuclear energy and RES-E in Scenario 1-DG (in TWh)

The change in generation structure is even more visible when taking a look at installed capacity (see Figure 35). Due to the much lower capacity factor of solar PV in comparison with offshore wind, RES-E capacity increases to almost 1,000 GW by 2030. Simultaneously, DG accounts for roughly 50% of total RES-E capacity or about one third more than in the original scenario.

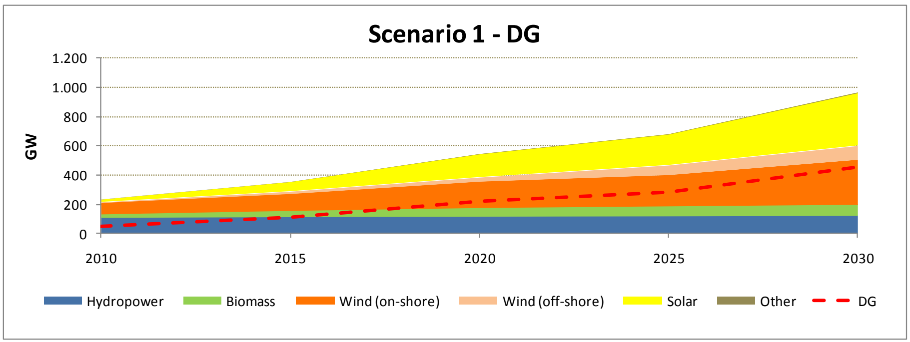


Figure 35 Installed RES-E capacity in Scenario 1-DG

30 Please note that the number for DG includes a limited contribution by small-scale cogeneration units, which we assume to be fuelled by (natural) gas.

3.2.2 Scenario 1a (Optimistic Scenario – High Demand)

As explained in Section 3.1 above, this scenario has been designed as follows:

- The demand in Scenario 1a is based on the assumptions of the 'Reference Scenario' in the Energy Roadmap 2050. In comparison to Scenario 1, net electricity demand in 2030 grows by some 250 TWh/a, to a total of nearly 3,500 TWh (see Figure 37).
- The share of RES-E in total electricity production is assumed to be the same as in Scenario 1. As a consequence, total production from RES-E increases by approx. 200 TWh to some 2,400 TWh in 2030. In order to ensure consistency with Scenario 1, the distribution of total production across individual technologies has been derived by linear interpolation between the production figures for the years 2030 and 2035 in the 'High RES-E' scenario of the Energy Roadmap 2050.[31]

Figure 36 illustrates the resulting changes in demand and production by RES-E. Simultaneously, the total production by DG also increases by almost 100 TWh and represents 27% of total production from RES-E.

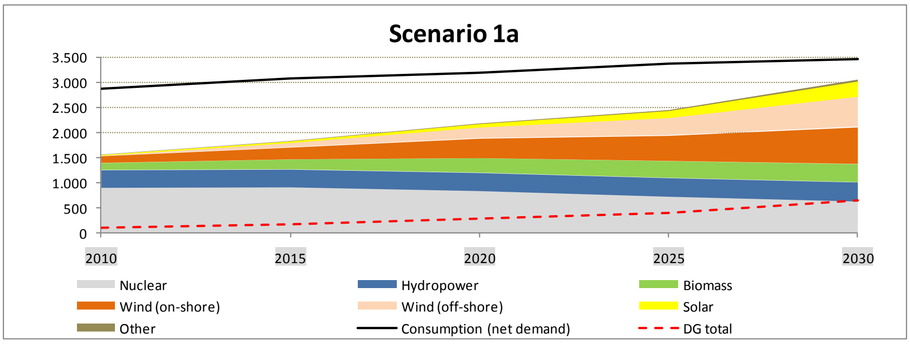


Figure 36 Demand vs. production from nuclear energy and RES-E in scenario 1a (in TWh)

Figure 37 shows the corresponding changes with regards to installed capacity. In comparison to Scenario 1, solar PV has increased by 24%, whilst wind power (on- and offshore) and biomass are some 11% and 7% higher, respectively. Conversely, there is less than 1% of additional hydro power capacity.

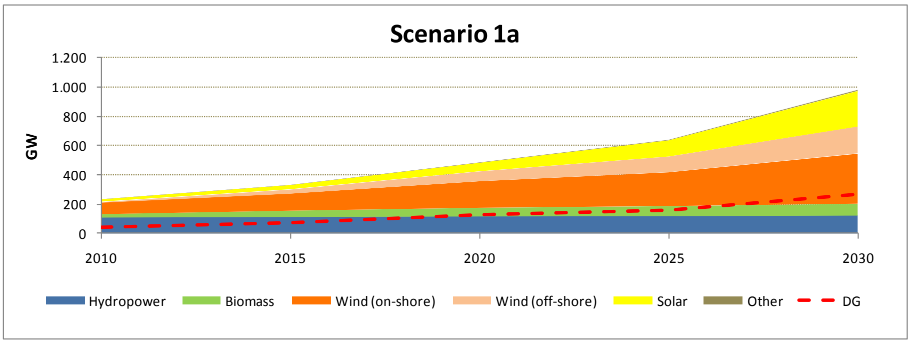


Figure 37 Installed RES-E capacity in Scenario 1a

Similar to Scenario 1, we have developed an additional variation with an increased share of DG (Scenario 1a-DG). This sub-scenario has been derived in a similar way as explained for Scenario 1 above (see Section 3.2.1). Consequently, Figure 38 shows a very similar trend as explained above, i.e. a delayed

31 In the 'High RES-E' scenario of the Energy Roadmap 2050, total production by RES-E increases from 2,200 TWh to 2,600 TWh, i.e. Scenario 1a is located approx. 'mid-way' between these two years. By applying the same ratio to all technologies, we obtain the same total production.

growth of offshore wind but a much faster expansion of solar PV. Compared to original Scenario 1a, DG increases by 36% to almost 900 TWh or 39% of total production from RES-E.

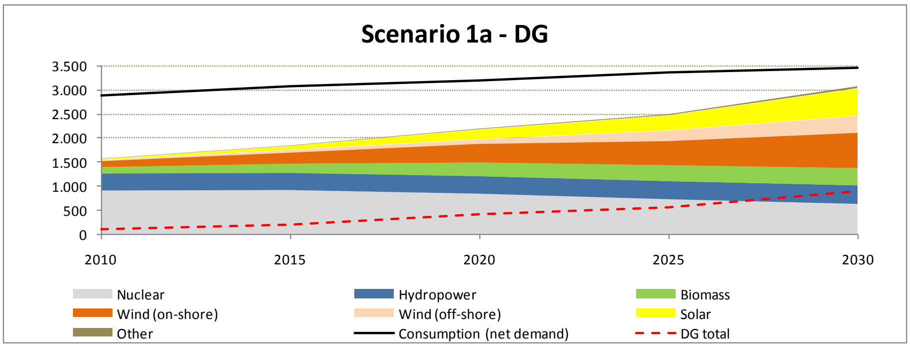


Figure 38 Demand vs. production from nuclear energy and RES-E in Scenario 1a – DG (in TWh)

Figure 39 shows the corresponding changes with regards to installed capacity, which are again reflecting the trend already shown for Scenario 1-DG above. Nevertheless, it is worth mentioning that this scenario represents the highest share of DG, with more than 500 GW of DG (equivalent to 51% of total capacity from RES-E).

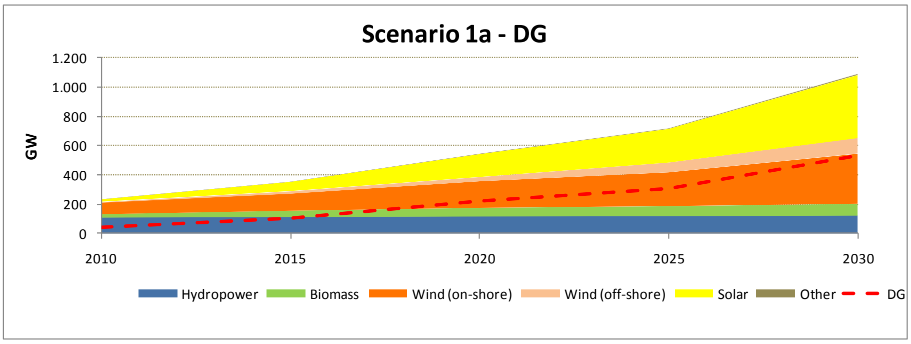


Figure 39 Installed RES-E capacity in Scenario 1a – DG

3.2.3 Scenario 1b (Optimistic Scenario – High Energy Efficiency)

Whilst Scenario 1a is based on a situation with additional consumption, this scenario represents an opposite development with the implementation of additional energy efficiency. As already explained in Section 3.1, it is based on the 'Energy Efficiency' scenario in the Energy Roadmap 2050 but has otherwise been designed in the same way as Scenario 1a.

More specifically, this implies the following (see Figure 40):

- The demand in Scenario 1a is based on the assumptions of the 'Energy Efficiency' scenario in the Energy Roadmap 2050. In comparison to Scenario 1, net electricity demand in 2030 decreases by approx. 225 TWh/a to roughly 3,000 TWh.
- Assuming the same share of RES-E in total electricity production as in Scenario 1, total production from RES-E in 2030 decreases to 2,075 TWh (-5%/-120 TWh).
- Total production by DG reaches approx. 520 TWh in 2030, i.e. it is about 7.5% lower than in Scenario 1.

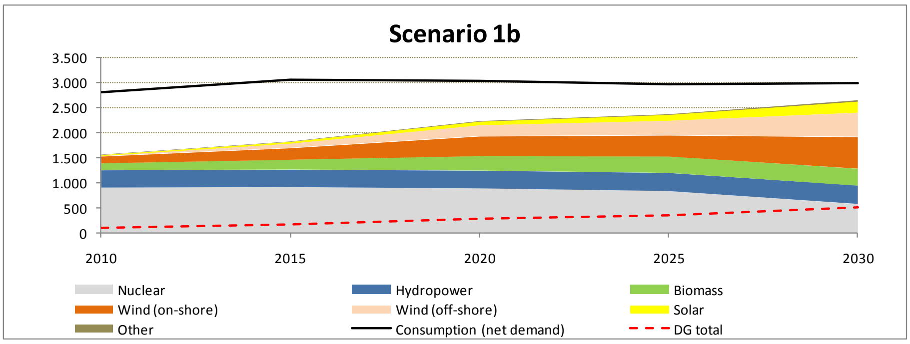


Figure 40 Demand vs. production from nuclear energy and RES-E in Scenario 1b (in TWh)

The reduction in annual production is reflected in similar changes in terms of installed capacity (see Figure 41). The reduction is most markable for solar PV (-12.5%) and offshore wind (-8.5%). In contrast, the installed capacity of onshore wind power plants is about 6% lower, whilst the capacity of biomass and hydro power plants remains virtually unchanged from Scenario 1.

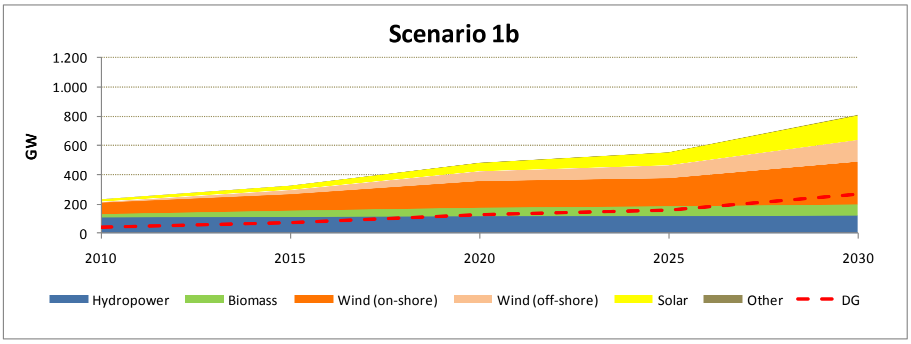


Figure 41 Installed RES-E capacity in Scenario 1b

As in the two previous cases, Scenario 1b is supplemented by an additional variation with an increased share of DG (Scenario 1b - DG), again using the same approach explained in Section 3.2.1. In direct comparison to Scenario 1b, production by offshore wind decreases by nearly 200 TWh (-40%), whilst the contribution from solar PV nearly doubles (see Figure 42). As a result, DG grows by about 9% to some 700 TWh.

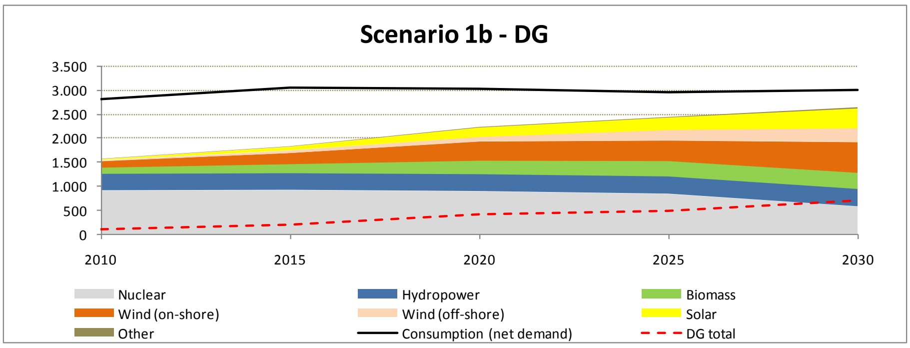


Figure 42 Demand vs. production from nuclear energy and RES-E in Scenario 1b – DG (in TWh)

In terms of capacity, these changes in the production structure correspond to an increase of total capacity from RES-E to 900 GW (see Figure 43). As a result, the share of DG increases from 33% in Scenario 1b to 48% in Scenario 1b - DG, i.e. from less than 300 GW to more than 400 GW.

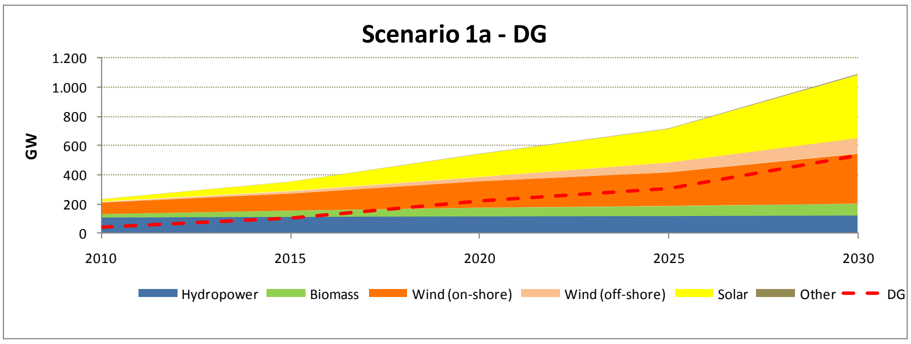


Figure 43 Installed RES-E capacity in Scenario 1b – DG

3.2.4 Scenario 2 (Middle Scenario)

Scenario 2 is based on the 'Diversified Supply Technologies' scenario in the Energy Roadmap 2050. Similar to Scenario 1, all assumptions with regards to the development of final electricity demand, nuclear power and RES-E have therefore been directly taken from PRIMES.

As already mentioned in Section 3.1 (see Figure 30 on p. 29) final electricity demand in the main Scenarios 1, 2 and 3 is broadly equivalent. In contrast, the share of RES-E in Scenario 2 remains more limited at 59% of final electricity demand and is almost 270 TWh lower than in Scenario 1. This reduction is fairly evenly distributed between solar PV, onshore and offshore wind and is between 75 TWh and 110 TWh each. The contribution of hydro power remains virtually unchanged whilst production from biomass shows a small growth of approx. 25 TWh. In contrast, nuclear energy decreases by about 100 TWh less than in Scenario 1 to a value of approx. 800 TWh in 2030.

Figure 44 shows the resulting evolution of the different technologies and final electricity demand between 2010 and 2030. Finally, the share of DG is slightly smaller than in Scenario 1 (24% vs. 26%) and amounts to less than 500 TWh.

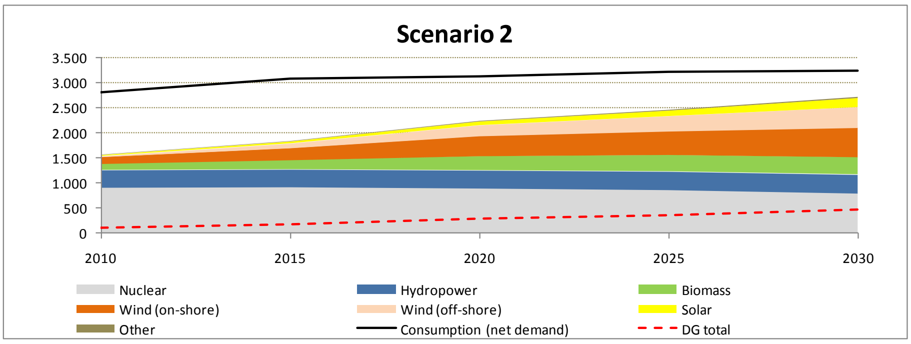


Figure 44 Demand vs. production from nuclear energy and RES-E in Scenario 2 (in TWh)

Figure 45 shows the corresponding changes in the development of installed capacity from RES-E. Overall, the volume of RES-E is 17% lower than in Scenario 1. More specifically, onshore and offshore wind power decreases by approx. 20% but solar power by more than 30%. As a result, the share of DG reaches about 31% in 2030, which is about 70 GW less than in Scenario 1.

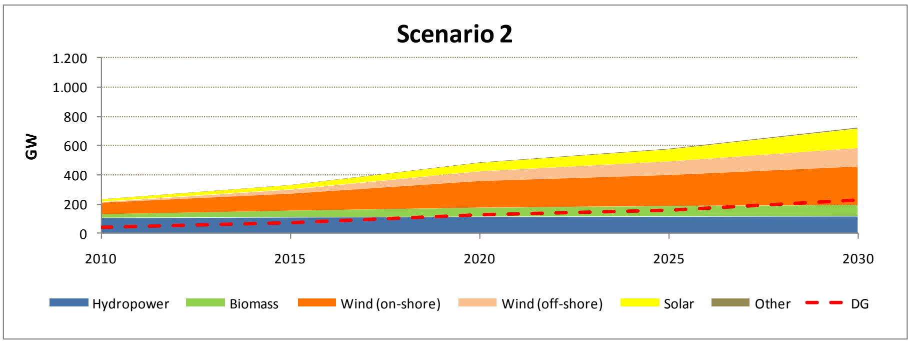


Figure 45 Installed RES-E capacity in Scenario 2

3.2.5 Scenario 3 (Pessimistic Scenario)

Scenario 3 is based on the 'Current Policy Initiatives' scenario in the Energy Roadmap 2050 and represents the only scenario, which does not comply with the decarbonisation path envisaged in the Energy Roadmap 2050. Again, all assumptions on the development of final electricity demand, nuclear power and RES-E have been directly taken from PRIMES.

Whilst the development of final electricity demand is roughly the same as in Scenarios 1 and 2, this scenario is characterised by the lowest penetration of RES-E. With 1,650 TWh, production from RES-E represents 51% of final electricity in 2030 only, which is 17% less than in Scenario 1 or 8% less than in Scenario 2. Again, this reduction is effectively split between onshore wind, offshore wind and solar PV, which are some 30%, 40% and 50% lower than in Scenario 1, respectively. The share of DG in total production from RES-E as well as in production from nuclear energy finally is comparable to scenario 2. Figure 46 provides an overview of the corresponding developments.

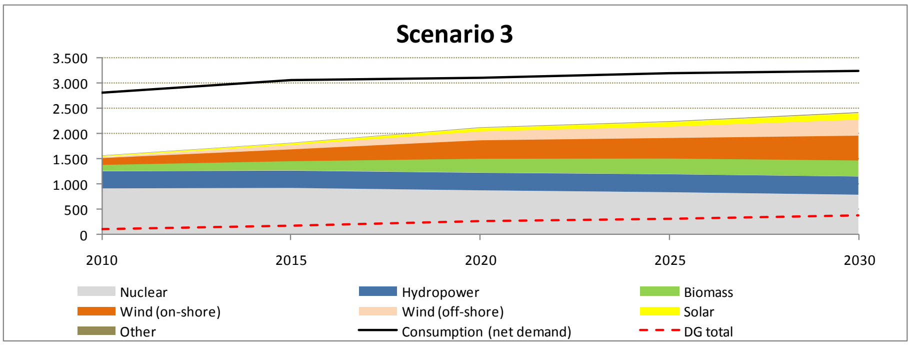


Figure 46 Demand vs. production from nuclear energy and RES-E in Scenario 3 (in TWh)

As shown in Figure 47, these changes imply that the capacity of RES-E reaches 600 GW in 2030 only, i.e. 30% less than in Scenario 1 or 15% less than in Scenario 2. Similarly, the penetration of DG stays below 200 GW or less than 30% of total RES-E.

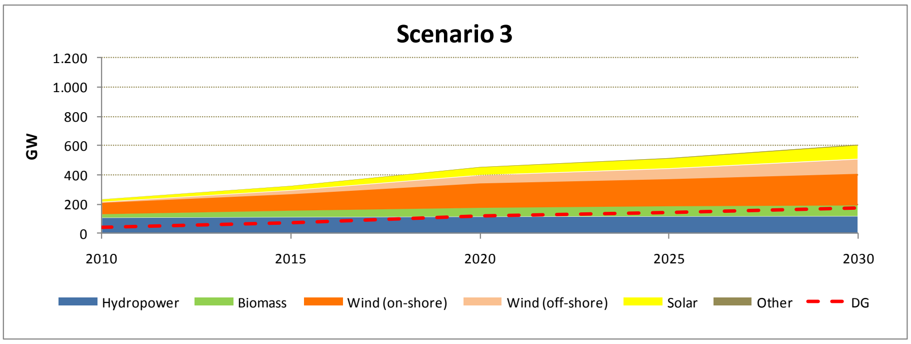


Figure 47 Installed RES-E capacity in Scenario 3

3.3 Summary of RES-E Development in Different Scenarios

Figure 48 provides an overview of the development of gross RES-E production in the different scenarios in the period 2010 to 2030. The figure clearly shows how the individual scenarios start to diverge especially after the year 2020. When neglecting Scenario 3, which does not meet the decarbonisation targets of the Energy Roadmap 2050, total production by RES-E varies between a minimum of 1,900 TWh and a maximum of 2,400 TWh in the year 2030. Please note that Figure 48 does not differentiate between the main variations of Scenario 1 and the additional variations with an increased share of DG since the total volume of RES-E does not change from the original scenarios in the latter case.

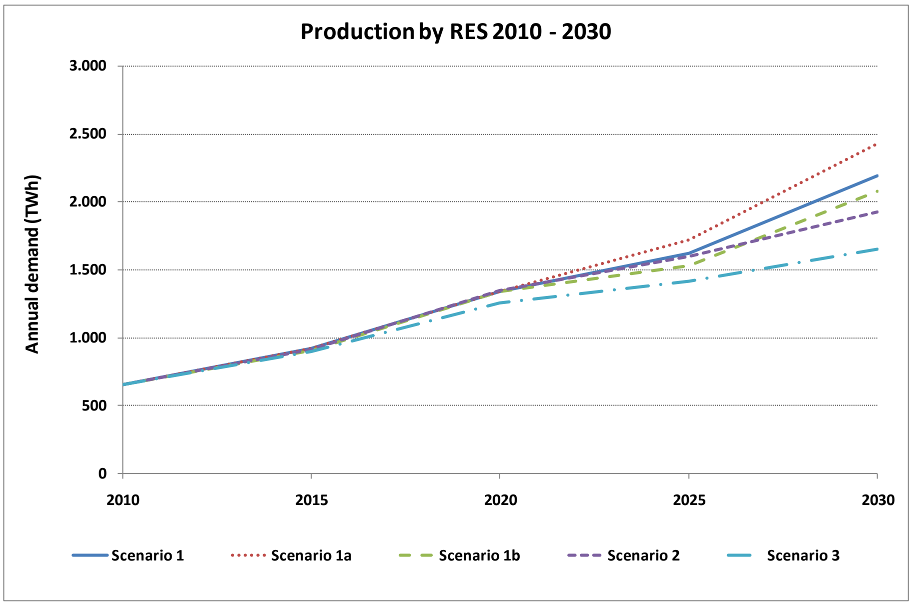


Figure 48 Development of gross RES-E production in different scenarios (2010 – 2030)

As Figure 49 shows the development of installed RES-E capacities basically follows a similar pattern as gross production (see Figure 48). In this case, however, the graph also shows the impact of the scenarios with an increased share of DG. More specifically, one can easily see how an increased penetration of solar PV, in return for a reduced use of offshore wind, increases the capacity requirement in each of the three corresponding scenarios.

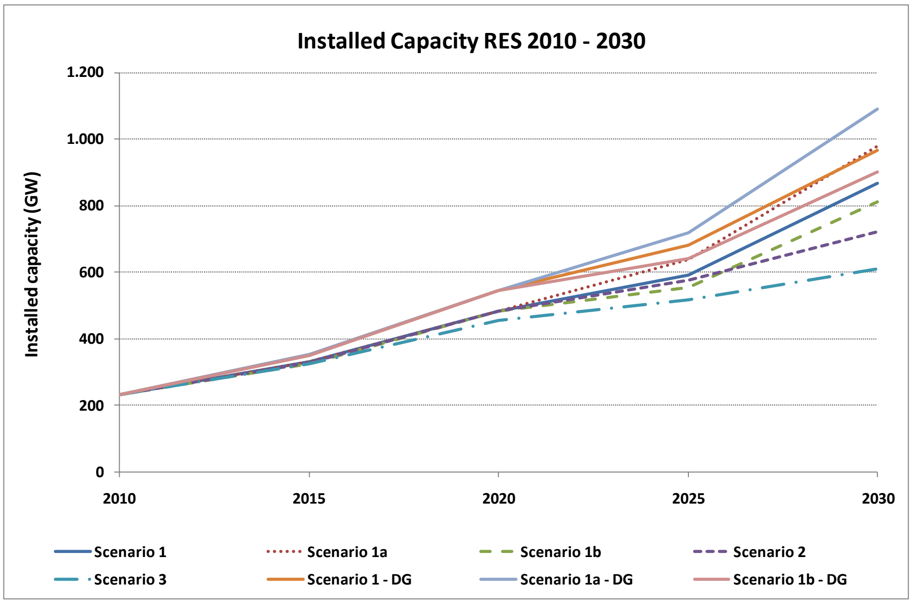
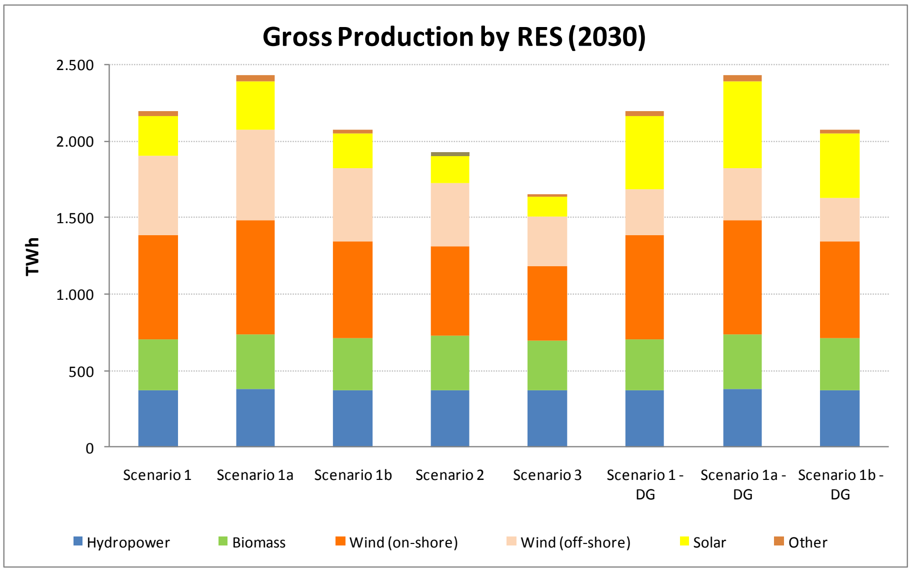


Figure 49 Development of installed RES-E capacity in different scenarios (2010 – 2030)

Figure 50 compares the structure of RES-E production and capacity in the individual scenarios. As already mentioned above, all scenarios have a comparable share of hydro power and biomass. In contrast, the share of onshore and offshore wind as well as solar PV varies considerably. Apart from the differences between the five main scenarios, one can clearly see the higher and lower share of solar PV and offshore wind, respectively, in the DG scenarios. Moreover, the direct comparison highlights the major impact, which the lower capacity factor of solar PV has on the capacity requirements in the DG scenarios. As a consequence, the capacity of solar PV is almost as large as the combined capacity of onshore and offshore wind in the DG scenarios. Moreover, variable RES-E (wind and solar) represents approx. 80% of total RES-E capacity in Scenario 1a as well as all in the three variations with an increased share of DG.



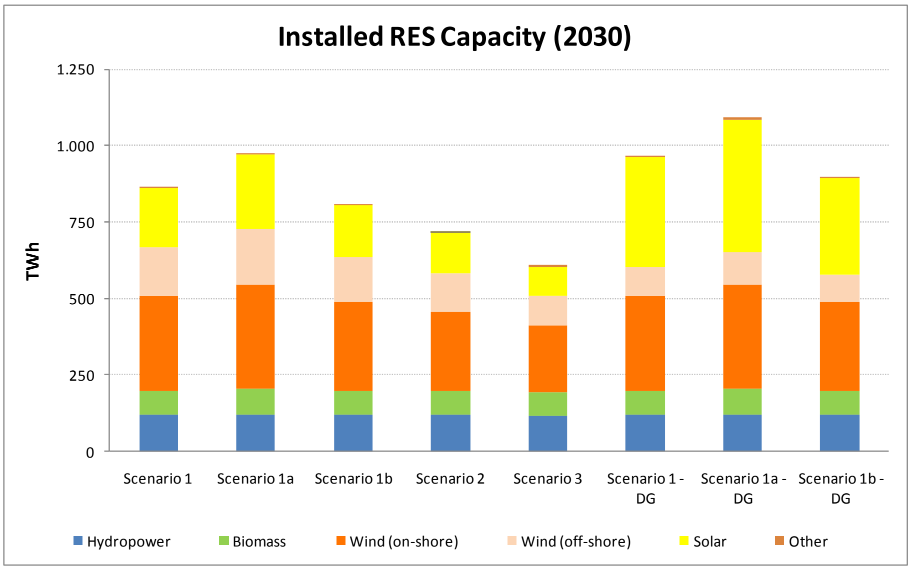
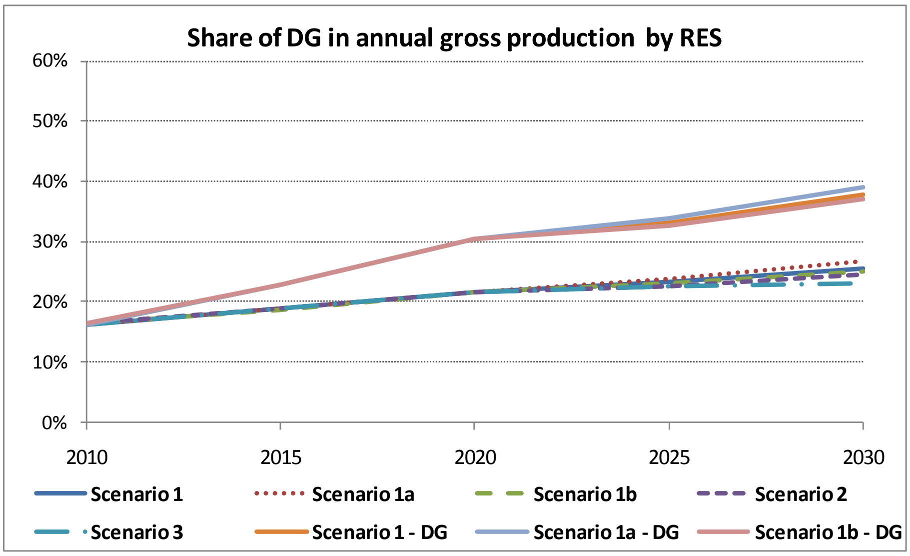


Figure 50 Structure of production from RES-E in different scenarios in the year 2030

Finally, Figure 51 depicts the share of DG in annual gross production and installed capacity by RES-E in the different scenarios over the period 2010 to 2030. This figure shows that the share of DG increases by about 50% in the main scenarios, which are directly based on the Energy Roadmap 2050. Moreover, it is also visible that the relative share of DG-RES remains in a fairly narrow range. In contrast, the share of DG in the three additional variations (1-DG, 1a - DG, 1b - DG) is much higher (about two thirds), although differences between the individual scenarios again remain limited.

Ist should be noted that the absolute volumes of DG-RES are very different due to the major differences in the total volume of RES-E in the main scenarios. For instance gross production from DG-RES varies between less than 400 TWh and 650 TWh in the main scenarios, or between less than 200 GW and approx. 350 GW in terms of installed capacity. Similarly, the contribution of DG-RES ranges between 700 TWh and nearly 900 TWh of gross production in the additional DG scenarios, or approx. 400 GW and 530 GW of installed capacity.



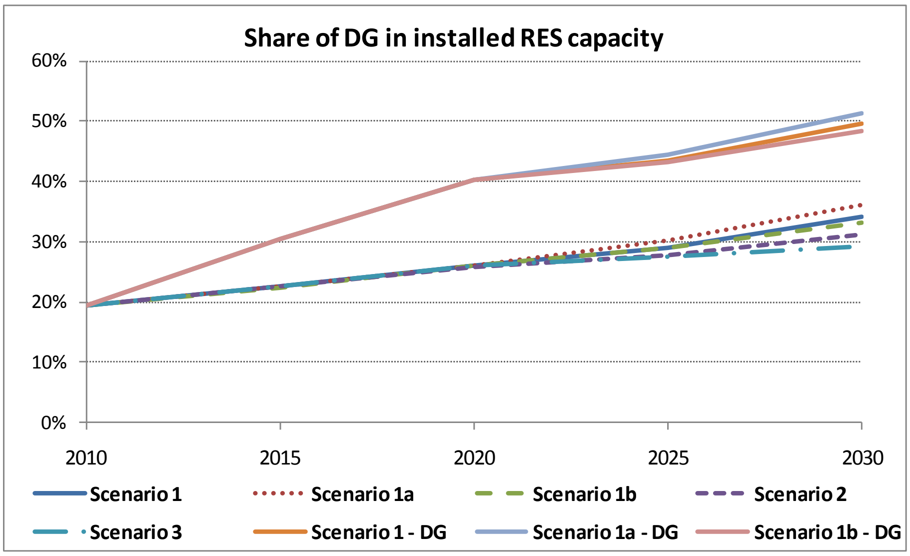


Figure 51 Evolution of DG-RES in different scenarios

Finally, Figure 52 and Figure 53 present the share contribution of different types of RES-E to decentralised generation in main scenarios (Figure 52) and the variations of scenario 1 (Figure 53). Figure 52 shows that DG-RES initially comes mainly from onshore wind and biomass but that it is increasingly dominated by solar power in Scenario 1. Indeed, except for a limited growth of onshore wind, almost all additional DG-RES comes from solar PV.

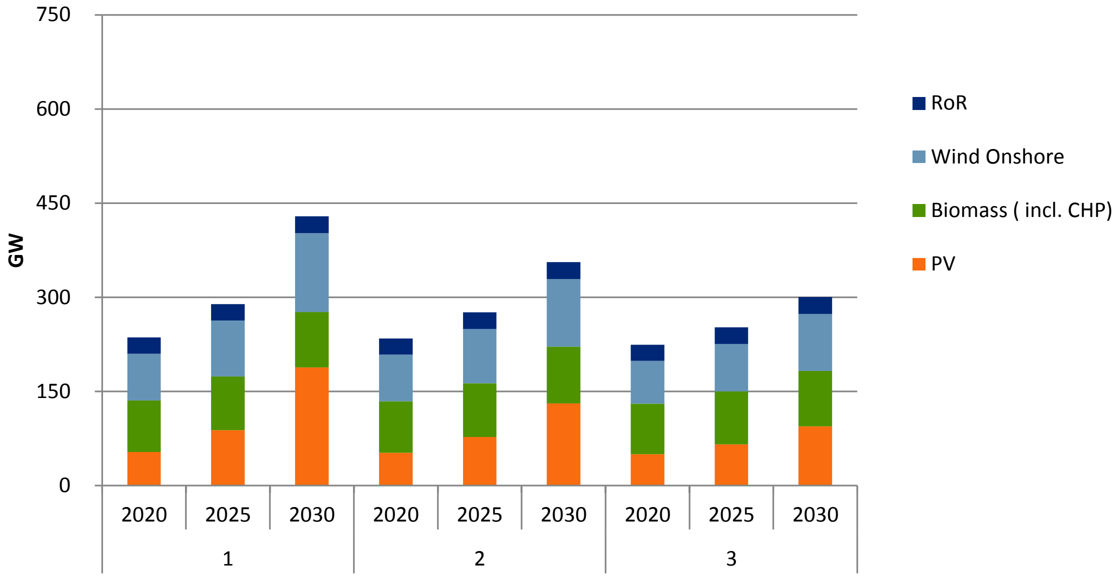


Figure 52 Composition of DG-RES by technology in the main scenarios

Figure 53 shows the corresponding values for the variations of Scenario 1. In this case, up to 740 GW of DG-RES are connected to European distribution grids. Again, this development is mainly driven by solar PV, although one can also observe an expansion of onshore wind.

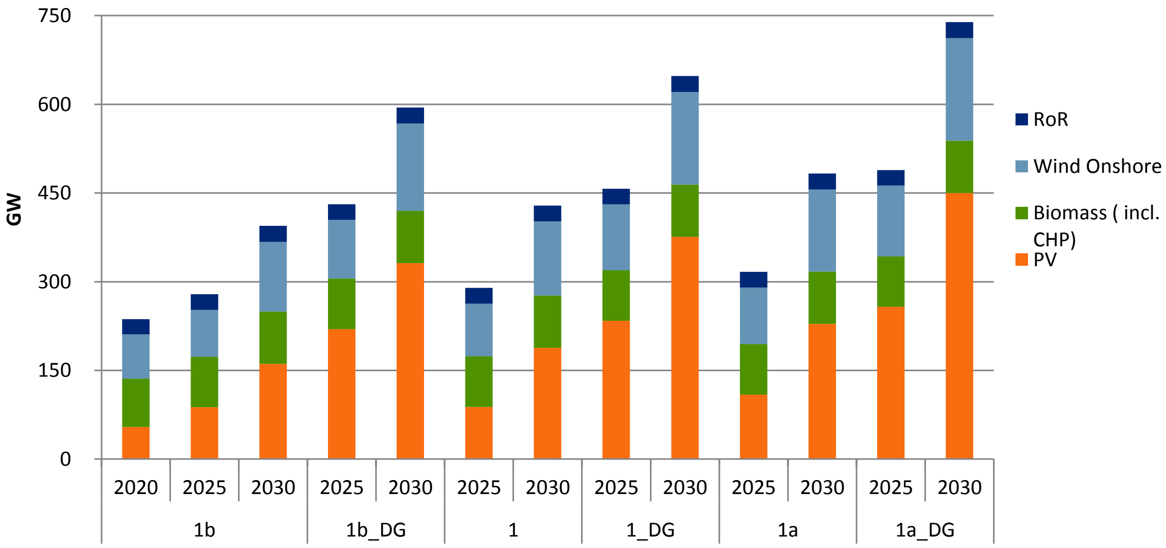


Figure 53 Composition of DG-RES by technology in the variations of Scenario 1

3.4 Outline of Selected Sensitivities

The different scenarios described so far are based on the Energy Roadmap 2050, although we have additionally considered variations with an increased share of decentralised generation. Nevertheless, they basically remain based on a single set of assumptions, with limited variations for instance with regards to the regional distribution of RES-E or the future structure of demand. Similarly, transmission expansion in the generation and transmission model is by definition constrained by the cost of alternative measures only, i.e. it does not consider any other constraints, such as public opposition, resource constraints etc.

For these reasons, we have supplemented the main scenarios and variations described in Section 3.1 above by a limited number of additional sensitivities as follows:

- 'Load-driven' RES-E expansion;
- Use of demand response;
- Increased use of heat pumps and EVs;
- Delayed transmission expansion; and
- No transmission expansion post 2020.

Table 19 provides a summary of the different sensitivity runs, which we address by additional simulations of one or more of the main models described above. In addition, Table 19 indicates the basis scenario that we consider.

Table 19 Summary of basis scenarios and sensitivities

Potential change / measure	Short name	Based on scenario
Sensitivities		
Load-driven RES-E expansion	Load Driven	1
Use of demand response	DR	1
Increased use of heat pumps and EVs	HP/EV	1a-DG
Delayed transmission expansion	Delayed transm.	1, 1-DG
No transmission expansion post 2020	No Transm.	1

In the following sections, we briefly present the potential changes and/or measures in each of the sensitivities and explain the underlying assumptions.

3.4.1 Load-Driven RES-E Expansion

The PRIMES scenarios in the Energy Roadmap 2050 are characterised by a relatively high share of wind power. In addition, they assume a resource-driven expansion of RES-E, i.e. new plants are primarily built in regions with the most favourable conditions for the production of electricity from RES-E. Although this approach helps to limit the cost of RES-E expansion, it may result in a very high need for transmission expansion.

To test for the sensitivity of these assumptions, we simulate an additional sensitivity that is characterised by:

- A shift of RES-E production from wind power to biomass and solar power; and
- A more 'balanced' distribution of wind and solar power, i.e. assuming a more local production structure than in the original scenarios.

With regards to the first aspect, this sensitivity combines the assumptions of Scenario 1-DG (with a shift from offshore wind to solar power) with an additional shift of production from onshore wind to biomass that lies in the range of 40 TWh to 100 TWh[32]. In addition, we assume a further shift of wind and solar power from coastal regions in North-Western Europe and the Iberian Peninsula to inland locations, i.e. mainly in Central Eastern and South-Eastern Europe.

In summary, this scenario includes the following changes compared to Scenario 1:

- First, we assume that the installed capacity of offshore wind amounts to 41 GW in 2020[33] and 61 GW in 2030[34]. Compared to scenario 1-DG, this corresponds to 331 TWh less of production or 37% of the original value.
- Secondly, we assume the same penetration of solar PV as in Scenario 1-DG, i.e. an increase of production by 217 TWh.
- Thirdly, we assume that the average growth of biomass in the period 2010 to 2025 continues after 2025, resulting in an additional 62 TWh of biomass in 2030.
- The balance of 52 TWh is covered by an accelerated growth of onshore wind outside the NSCOGI region (excl. Sweden), Spain, Portugal and Italy, which roughly implies that the production volumes in these countries, which are reached in the year 2040 in the original scenario, are already achieved in the year 2030.

Table 20 compares the assumptions on production and installed capacity by RES-E technology for the original Scenario 1, the variation with an increased penetration of DG (1-DG) and the load-driven scenario.

Table 20 Summary of assumptions on Scenarios 1, 1-DG and 1 - LD

Technology	**Production (TWh)**			**Capacity (GW)**		
	Scenario			**Scenario**		
	1	**1-DG**	**Load-driven**	**1**	**1-DG**	**Load-driven**
Hydropower	375	375	375	120	120	120
Biomass	333	333	395	78	78	84
Wind (onshore)	674	674	726	309	309	338
Wind (offshore)	524	307	193	160	94	61
Solar	256	473	473	195	361	361
Other	31	31	31	5	5	5
Total RES-E	2,193	2,193	2,193	867	967	969

Figure 54 and Figure 55 provide an overview of the development of production and installed capacity, respectively, over the time period from 2010 to 2030.

32 In the PRIMES scenarios, the total contribution from biomass grows by 40 TWh and 106 TWh from 2030 to 2035 and 2040, respectively.

33 Based on the National Renewable Energy Action Plans (NREAPs) of the EU Member States

34 Based on 55 GW of offshore wind as defined by the 'NSCOGI Reference Scenario' in a recent report by the 'The North Seas Countries' Offshore Grid Initiative' (NSCOGI) and a proportional reduction of offshore wind in other Member States leading to an additional 6 GW of capacity.

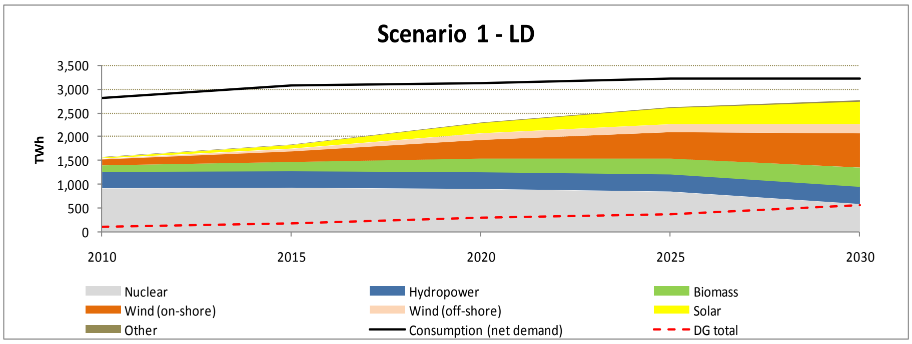


Figure 54 Demand vs. production from nuclear energy and RES-E in the load-driven scenario

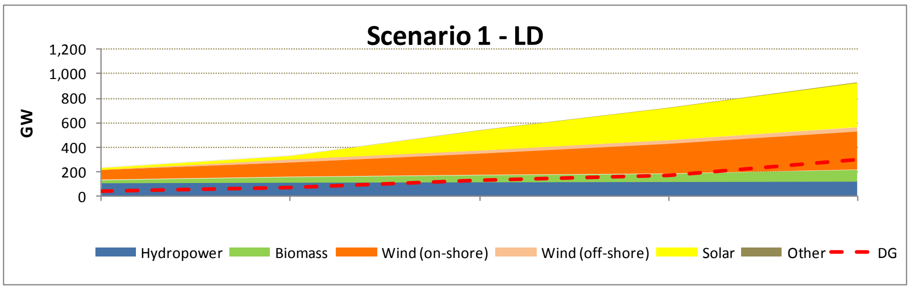


Figure 55 Installed RES-E capacity in the load-driven scenario

3.4.2 Use of demand response

In the context of discussions around the need for additional flexibility in power systems with a high penetration of variable RES-E, the use of demand response (DR) is often discussed as an essential precondition. Moreover, various Member States already promote the participation of DR in the power market, or a planning to do so. In the future, the flexibility available from demand may therefore well be larger than today.

Due to its potential importance, we specifically discuss the possible role of DR as an instrument for enabling the integration of RES-E as one possible technical solution in Chapter 6. Based on discussions with DG ENER, we have additionally included a separate sensitivity, which is based on scenario 1 and which looks at the impact of DR in the context of the initial analysis. More specifically, this sensitivity assumes a limited availability of DR, with the ability to shift up to 7.5% of daily peak load and 5% of daily consumption (please refer to Section 6.2.4 for further details).

3.4.3 Increased use of heat pumps and electric vehicles

The main scenarios in the Energy Roadmap 2050 assume a very limited penetration of electric vehicles (EVs) in the time horizon until 2030. Although this is not explicitly mentioned, we believe that the Energy Roadmap 2050 also assumes a limited use of heat pumps.

In contrast, EVs and heat pumps (HPs) are often seen as an important instrument for increasing energy efficiency and reducing CO_2 emissions. At the same time, an increased penetration of HPs and EVs would also have a tangible impact on the power system:

- First, both options increase final electricity demand, primarily at the residential level. Depending on the ratio between consumption and decentralised generation, this may either increase or decrease the need for network extension at the distribution level.

- In addition, increasing consumption will require more electricity to be produced. Assuming that the same level of RES-E shall be maintained as in the basic scenario, this will require additional production capacity (RES-E and conventional) and, potentially, additional reinforcements of the transmission grid.
- These effects may be further reinforced by the consumption profile of heat pumps and electric vehicles, respectively. Without any additional measures (see below), these applications will generally increase the spread between peak and trough load. Moreover, it is worth noting that HPs have a clear seasonal profile (i.e. temperature dependent), whilst the consumption of EVs varies by season/temperature and day of the week (i.e. weekday vs. Saturdays and Sundays).
- Apart from their direct impact on electricity consumption, HPs and EVs have inherent storage capabilities, i.e. heat and chemical storage, respectively. These storage capabilities cannot only be used to 'flatten' the native load profile of these applications but can also be used to provide additional demand response to the power system.

Based on these considerations, we have considered a sensitivity case with an increased penetration of EVs and HPs. This sensitivity assumes an incremental demand of approx. 250 TWh, which is split 60:40 between HPs and EVs. As a consequence, this sensitivity is basically comparable with Scenario 1a - DG[35], but with a different hourly load profile.

3.4.4 Delayed and no transmission expansion

In our basic analysis, the generation and transmission model fully optimises the expansion of transmission and back up generation post 2020. As the results of the initial simulations during the project have shown, this may result in very high levels of interconnection. Although these results do represent an optimal infrastructure, they may be perceived as unrealistic. Indeed, experience to date shows that transmission expansion in many Member States is seriously delayed, among others due to public opposition. Consequently, it seems reasonable to assume that similar problems may also arise in the future. In contrast, the penetration of RES-E in several Member States has grown much faster than anticipated in recent years.

Secondly, high levels of interconnection will generally result in less volatile power prices and increasing price convergence between different countries. This in turn may have a strong impact on the profitability of different types of generation (and storage) and hence on incentives to invest into these technologies.

For these reasons, we have analysed two additional sensitivity runs as follows:

- **Delayed transmission expansion** – where incremental transmission capacity is reduced compared to the outcome of the original scenario, i.e. by 50% for all incremental capacity up to 5,000 MW and 66% (i.e. 2/3) for all incremental capacity in excess of 5,000 MW. Please note that these restrictions apply to onshore connections only, whilst there are not constraints to the expansion of offshore connection. This sensitivity is being considered for Scenarios 1 and 1-DG.
- **No transmission expansion post 2020** – where we do not allow for any expansion of onshore grids or offshore connections after the year 2020.

The differentiation between 'smaller' and 'larger' volumes of incremental capacity in the first case serves to reduce extreme outcomes. In addition, it also reflects the assumption that larger projects are more likely to face technical barriers and/or opposition. At the same time, the proposed method has the

35 Since HPs and EVs both contribute to decentralized demand, it seems useful to combine them with an increased use of DG.

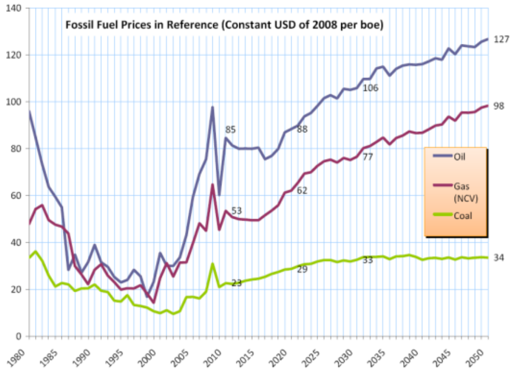
advantage that it is not necessary to take decisions on individual interconnectors, which would necessarily remain arbitrary.

3.5 Assumptions on Fuel and CO2 Prices

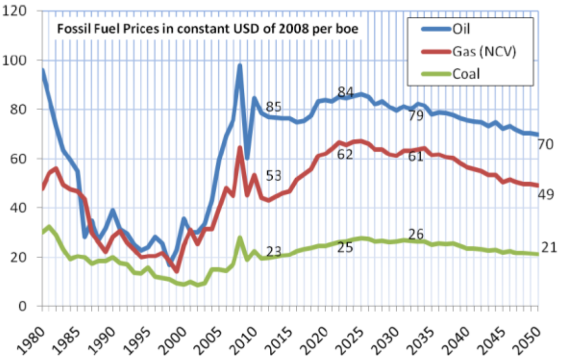
3.5.1 Fuel Prices

In line with the overall approach, fossil fuel prices have been taken from the Energy Roadmap 2050 (see Figure 56). In addition, we have taken the following assumptions for other fuels:

- The price of lignite is assumed to represent 40% of the price for imported hard coal;
- The price of uranium is kept constant at a level of 0.73 €/GJ[36]; and
- For biomass, we assume a notional fuel price of approx. 4 €/GJ.



Current Policy Initiatives (Scenario 3)



Decarbonisation Scenarios (Scenario 1,2)

Figure 56 Development of fossil fuel prices (Source Energy Roadmap 2050)

3.5.2 CO_2 Emissions and Price of Carbon Allowances

To ensure that all scenarios remain with the decarbonisation pathways of the Energy Roadmap 2050, we have imposed a limit on total CO_2 emissions from electricity production. The corresponding limits have been derived from the total CO_2 emissions for the power generation and district heating sector as specified in the Energy Roadmap 2050. Since our simulations do not cover the entire heating sector, we have split up overall emissions between both sectors based on the final energy demand for electricity and heat[37].

In addition, we have also considered the development of carbon allowance prices, which represent an important driver for electricity prices. The corresponding values for the years 2020 and 2030 as well as the underlying assumptions are summarised in Table 21.

36 Since the variable cost of nuclear energy is much lower than those of conventional power plants, the exact level is of limited relevance for the outcome of this study.

37 For simplification, we have assumed that the average efficiency of heat production in conventional generation to be approx. two times as large as for electricity production.

Table 21 Development of the price for carbon allowances (€/t)

Scenario	2020	2030	Source (RM 2050 scenario)
Scenario 1	25	35	High-RES-E
Scenario 1a	20	30	Average of 'High-RES-E' and 'High Energy Efficiency' scenarios
Scenario 1b	25	35	High-RES-E scenario
Scenario 2	25	52	Diversified Supply Technologies
Scenario 3	15	32	Current Policy Initiatives

4 ANALYSIS OF FUTURE INFRASTRUCTURE REQUIREMENTS AND COSTS OF ELECTRICITY SUPPLY

4.1 Introduction

This Section provides an overview of changes to the structure and use of the European power system that are associated with different penetrations of centralised and decentralised RES-E, as well as the resulting impacts on the costs of electricity supply. A considerable part of this chapter is devoted to an in-depth discussion and analysis of investments into generation, transmission and distribution infrastructure for the different scenarios outlined in Section 3 above. In addition, we also present the development of electricity generation and the corresponding impact on fuel consumption and CO_2 emissions and discuss the overall impact on the costs of electricity supply. Finally, this chapter also discusses important cost drivers and technical barriers for increasing the use of RES-E as well as the specific role and impact of DG on infrastructure requirements and the costs of electricity supply.

In order to facilitate the presentation and discussion, this chapter is structured as follows:

- Section 4.2 compares the overall structure of installed generation capacity and discusses the need for investments into conventional generation technologies, including back up capacity;
- Section 4.3 analyses the need for transmission expansion;
- Section 4.4 presents the results of the distribution analysis;
- Section 4.5 summarises the development of electricity generation, curtailment of RES-E, fuel consumption and CO2 emissions;
- Section 4.6 determines the incremental costs of electricity supply, including investments into new infrastructure and operating expenditure of electricity generation;
- Section 4.7 identifies important drivers on infrastructure requirements; and
- Section 4.8 discusses the role and impact of DG on infrastructure and costs.

4.2 Investments into Generation Capacity

In the period until 2030, investments into RES-E and conventional plants are required in order to meet increasing electricity demand, replace decommissioned generation capacity and increase the share of RES-E. As discussed in Section 3, our assumptions on the development of RES-E and nuclear power are based on the Energy Roadmap 2050. Conversely, the need for investments into additional conventional generation technologies has been derived from a long-term generation capacity expansion model (see Section 2.1). The expansion of conventional capacities takes into account the underlying economics and technical parameters of different generation technologies, in order to determine an optimal combination of new builds that minimizes the net present value of total system costs over the entire planning horizon. In addition, the optimisation takes into account the scenario-specific carbon emission targets estimated from the Energy Roadmap 2050 as well as several other parameters, such as fuel and CO_2 prices and electricity demand.

Figure 57 shows the evolution of installed generation capacity in the EU-28 for the three main scenarios 1, 2 and 3 and the years 2020, 2025 and 2030. A comparison of the individual results leads to the following main observations:

- A growing penetration of (variable) RES-E coincides with an increasing amount of installed generation capacity and an increasing volume of back up capacity;
- Whilst the volume of conventional generation capacities decreases over time, there are no significant differences between the three main scenarios; and
- The evolution of gas- and coal-fired capacities varies substantially across the different scenarios.

Figure 57 shows that total generation capacity increases more than peak load as the share of RES-E grows. This trend is visible for each individual scenario as well as when comparing the three different scenarios against each other. To a large extent, this effect can be explained by the fact the increasing share of RES-E is predominantly driven by wind power plants and solar PV. Since these technologies have lower capacity factors than conventional thermal plants, more capacity is required to deliver the same volume of energy.

In addition, a larger share of variable RES-E also leads to an increasing amount of back up capacity. This indicates that the growth in total capacity is not only driven by the lower capacity factors but also by the uncertain output from the corresponding RES-E technologies. Consequently, additional (back up) capacity is required, in order to meet demand and ensure system reliability at time when there is insufficient energy available from wind and solar plants. In this context, it is important to note the specific role of back up capacity:

- Most types of conventional generation mainly serve as a provider of energy. Although they also contribute to reliability (i.e. generation adequacy), their main role is to supply electric energy. Consequently, these plants are characterised by limited variable costs, whilst they may require relatively large capital investments.
- Conversely, back up capacity primarily serves as a provider of capacity in order to ensure generation adequacy. More specifically, the function of back up plants is to provide electricity in exceptional circumstances only, i.e. when other types of generation are not available. In contrast to other types of generation, the variable cost of back up plants are thus of secondary importance, whereas their capital costs should be as low as possible.

The need for back up capacity is not limited to power systems with a considerable share of variable RES-E. Indeed, back up plants are principally required in every power system, i.e. to ensure generation adequacy when other plants are not available. However, their role increases in a power system where a larger share of total production is provided by generators that cannot provide sufficient 'firm capacity', i.e. which cannot guarantee production at all times. Apart from variable RES-E, this is a traditional characteristic of power systems dominated by a large share of hydro power.

Besides the need for back up capacity, it is also interesting to note the development of conventional generation capacities, including coal- and gas-fired plants as well as nuclear power. On first sight, the strong development of RES-E seems to lead to the displacement of conventional capacities, i.e. installed capacity from these technologies decreases over time. When comparing the three main scenarios against each other, however, we observe virtually the same level of installed capacity from conventional plants (approx. 400 GW) in 2030. Similarly, when also considering hydro power and biomass, the total amount of firm capacities amounts to some 600 GW in all three main scenarios, which is only slightly below peak load. Noting that all three scenarios are based on a very similar level of consumption, these observations indicate that the additional capacity from variable RES-E has a limited contribution to the amount of firm capacity that is required to ensure reliability.

Thirdly, it is interesting to note the different development of gas- and coal-fired capacities. Whilst coal-fired power plants disappear almost entirely in scenario 2, we observe substantial remaining coal-fired capacity but very little gas-fired plants in scenario 3, which is characterised by low CO_2 prices.

Scenario 1	2020	2025	2030
Nuclear	125	107	91
Coal conv.	119	69	44
Gas conv.	155	138	92
Oil	33	11	6
Back up	63	89	157
Hydro	115	117	120
Biomass	61	70	78
Wind (on)	186	223	313
Wind (off)	64	92	157
Solar	54	88	188
Other RES-E	2	2	5
Total	**976**	**1,008**	**1,250**

Scenario 2	2020	2025	2030
Nuclear	125	107	105
Coal conv.	107	57	32
Gas conv.	167	189	143
Oil	33	11	6
Back up	61	56	112
Hydro	115	117	119
Biomass	62	72	77
Wind (on)	185	217	269
Wind (off)	65	91	124
Solar	53	78	131
Other RES-E	3	4	6
Total	**974**	**998**	**1,122**

Scenario 3	2020	2025	2030
Nuclear	125	106	102
Coal conv.	145	122	111
Gas conv.	144	124	78
Oil	33	11	6
Back up	44	67	91
Hydro	115	116	118
Biomass	60	70	74
Wind (on)	171	190	227
Wind (off)	53	69	98
Solar	50	66	94
Other RES-E	2	4	5
Total	**941**	**945**	**1,004**

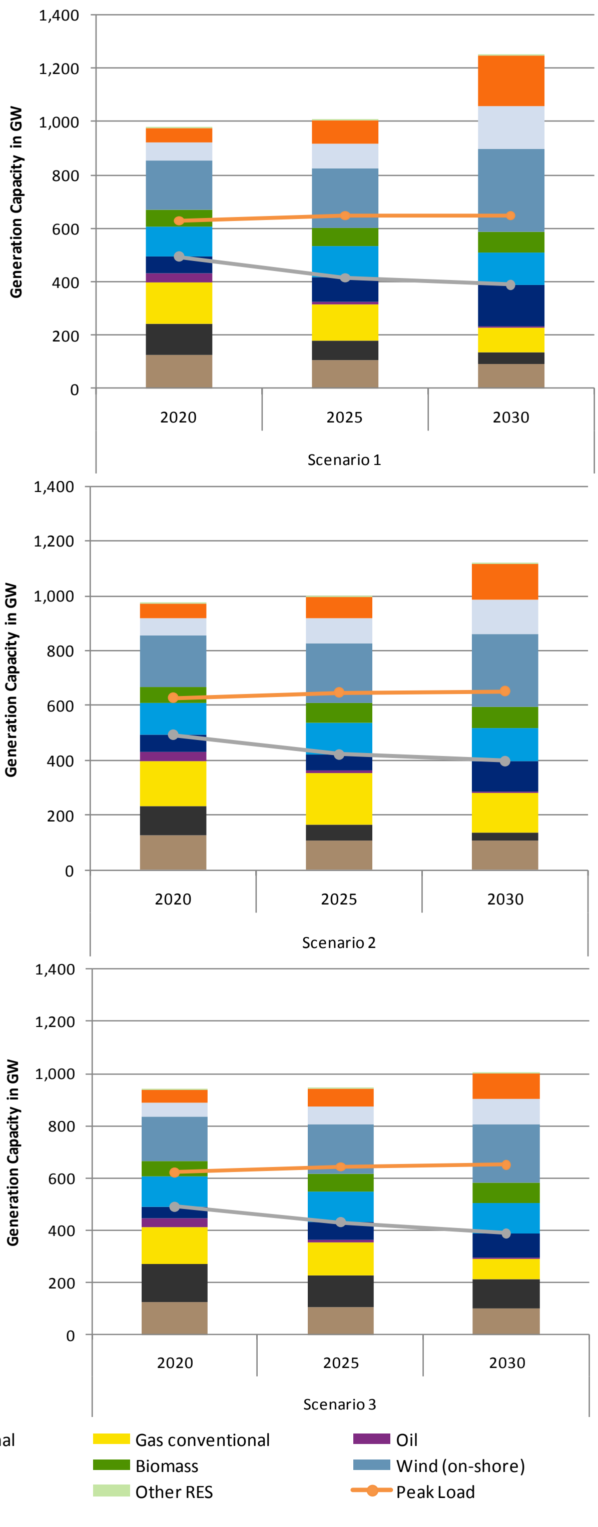


Figure 57 Generation capacity in the three main scenarios (2020 - 2030)

Figure 58 below displays the development of generation capacities for the variations of scenario 1. In this case, we specifically note the following:

- The volume of thermal generation capacity increases in lines with electricity demand;

- The total volume of installed generation capacity as well as the need for back up capacity are highest in those variations with a higher level of decentralised generation, i.e. with a shift from offshore wind to solar PV; and
- The structure of conventional thermal generation is increasingly dominated by back up capacity as the share of variable RES-E grows.

Figure 58 clearly shows that the changes in electricity demand are reflected by a similar pattern for the amount of installed generation capacities. Apart from total generation capacity, this observation also applies when considering thermal power plants only (coal, gas, nuclear). This principally confirms our earlier findings on the limited contribution of variable RES-E to firm capacity, which is required to ensure reliability.

In the variations with an increasing share of decentralized generation ("DG"), we assume that a higher share of demand is covered by solar PV, whilst the contribution from offshore wind does not increase as rapidly as in the main scenarios. Given that solar PV has significantly lower capacity factors than offshore wind, it is thus not surprising to see an increasing need for capacity. But again, this development also leads to an increasing need for back up capacity (and thermal generation capacity in general), indicating an even lower contribution of solar PV to firm capacity than wind power.

Finally, it is interesting to note that the structure of conventional thermal generation is dominated by back up capacity in the year 2030. In other words, most of the (incremental) capacity from thermal power plants is built to ensure reliability but not to deliver energy.

2025	1b	1b-DG	1	1-DG	1a	1a-DG
Nuclear	107	107	107	107	107	107
Coal conv.	73	77	69	75	65	69
Gas conv.	123	124	138	137	148	152
Oil	11	11	11	11	11	11
Back up	55	56	89	93	87	103
Hydro	117	117	117	117	117	117
Biomass	69	69	70	70	70	70
Wind (on)	198	198	223	223	239	239
Wind (off)	86	65	92	65	104	65
Solar	88	220	88	234	109	257
Other RES-E	2	2	2	2	2	2
Total	**929**	**1,045**	**1,008**	**1,135**	**1,060**	**1,194**

2030	1b	1b-DG	1	1-DG	1a	1a-DG
Nuclear	91	91	91	91	91	91
Coal conv.	47	51	44	50	40	44
Gas conv.	77	78	92	91	102	106
Oil	6	6	6	6	6	6
Back up	128	137	157	173	170	199
Hydro	120	120	120	120	121	121
Biomass	78	78	78	78	83	83
Wind (on)	295	295	313	313	347	347
Wind (off)	144	86	158	92	179	104
Solar	161	332	188	376	229	450
Other RES-E	5	5	5	5	5	5
Total	**1,151**	**1,277**	**1,250**	**1,394**	**1,371**	**1,554**

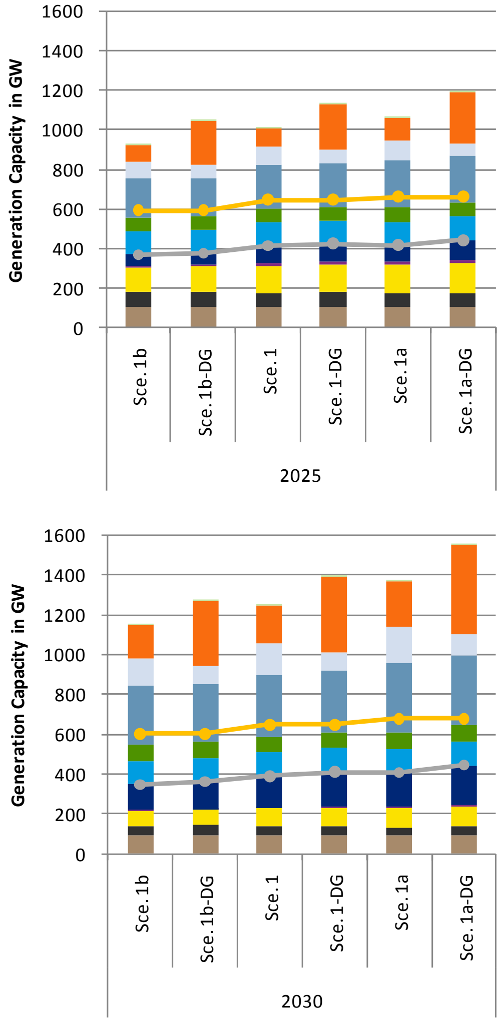


Figure 58 Generation capacity in the variations of scenario 1 (2025 and 2030)

Figure 59 reveals that the level of capacity expansion is very similar across the three main scenarios with about 200 GW. However, there are significant variations with regards to the type of new-built generation. In scenario 1, incremental capacity is dominated by back up capacity, whereas we observe a limited addition of other gas-fired plants and hardly any new coal plants only. In contrast, the amount of conventional capacities (other than back up capacity) entering the system is significantly higher in scenarios 2 and 3. Moreover, there are no new coal plants but a large volume of traditional gas-fired plants in scenario 2[38], whilst the opposite is true for scenario 3. This difference can probably be explained by the relatively high CO_2 prices in scenario 2 but much lower CO_2 prices in scenario 3. This observation indicates that fuel and CO_2 prices will continue to be main drivers for the future development of conventional generation capacities.

38 From 2025 onwards we also allow building of a limited volume of coal- and gas-fired plants equipped with carbon-capture and storage (CCS) technology. Please note that scenario 2 is the only scenario, in which we see some 0.5 GW of gas-fired CCS technology being commissioned by 2030.

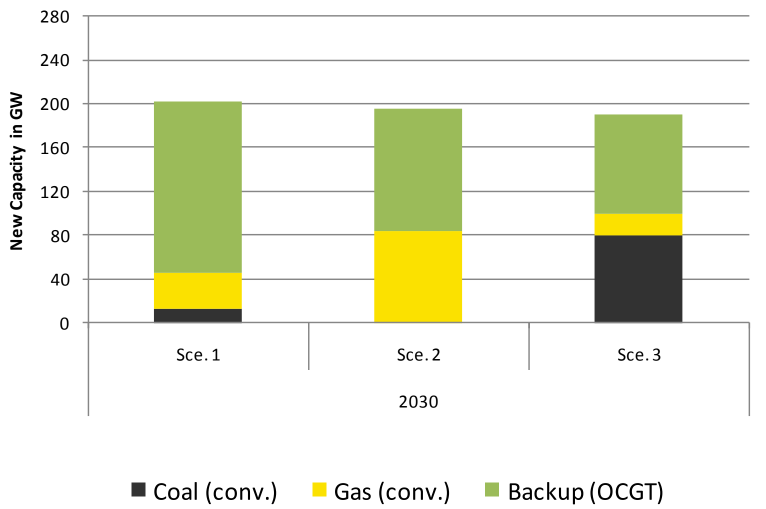


Figure 59 Incremental capacity from thermal generation in the three main scenarios in the year 2030

Figure 60 shows the corresponding results for the variations of Scenario 1. Since the underlying fuel and CO_2 prices are based on the same assumptions as scenario 1, the new-built capacity mainly comprises of gas-fired technology. Moreover, we observe limited variations of conventional gas and coal plants, again with a positive correlation between electricity demand and the share of DG, on the one hand, and the need for thermal generation capacity, on the other hand.

In addition, Figure 60 shows marked differences in the need for back up capacities, which are much higher in the DG scenarios. At the same time, total production from RES-E remains virtually unchanged between the 'centralised' and 'decentralised' scenarios (see Section 4.5.1). Arguably, these differences reflect a limited capacity credit of variable RES-E in general and of solar PV in particular. Even when taking into account stochastic variations over larger areas, the minimum amount of production that can be guaranteed by variable RES-E at all times remains limited. Moreover, this limitation is particularly relevant for solar PV since production is by definition limited to daylight hours and furthermore correlated with the season. Consequently, solar PV can hardly provide firm capacity during evening peak hours as well as cold and windy winter days.[39]

[39] As already pointed out in Section 2.4.2 the need for back-up capacity may be under-estimated, such that the differences in terms of required back-up capacity may be even larger than shown in Figure 60.

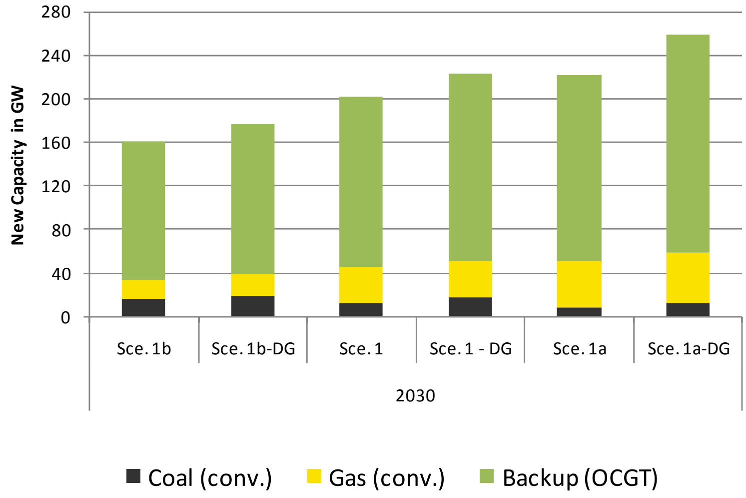


Figure 60 Incremental capacity from thermal generation in the variations of Scenario 1 in the year 2030

Power systems with high shares of variable RES-E, particularly wind and solar power, may require back up capacity to ensure supply during periods of low RES-E production. Even in well interconnected power systems with significant transmission capacities, considerable amounts of conventional generation capacity may thus be required. By definition, back up plants will have very low capacity factors such that it is important to limit fixed cost, i.e. CAPEX, whilst operational efficiency is of lesser concern. For this reason, we have generally assumed open cycle gas turbines (OCGTs) fired by natural gas as a preferred option, although the same function could just as well be taken by oil-fired OCGTs, gas motors or diesel engines.

While Figure 61 below presents the required back up capacity for the three main scenarios and the variations of Scenario 1, Figure 62 displays the corresponding results for the sensitivities of Scenario 1. These comparisons reveal that the need for back up capacity is generally higher in scenarios with:

- An increased contribution from variable RES-E;
- An increased contribution from decentralised RES-E, i.e. mainly solar PV, with the notable exception of the load-driven sensitivity of Scenario 1;
- A delayed expansion of transmission infrastructure; and
- An increased usage of heat pumps (HPs) and electric vehicles (EVs).

As the left part of Figure 61 shows, the need for back up capacity is highest in scenario 1, which is characterised by the highest penetration of wind and solar power among the three main scenarios. Conversely, scenarios 2 and 3 require less back up capacity, although absolute volumes still grow over time[40]. On first sight, this might suggest that the need for back up capacity is primarily driven by the share of variable RES-E. However, we observe a similar trend for the variations of scenario 1 (see right part of Figure 61), which are characterised by a very similar share of variable RES-E. Still, the absolute volume of variable RES-E strongly increases from scenario 1b to scenario 1a (due to higher demand).

The right part of Figure 61 shows that the variations with a higher share of decentralised generation (DG) require more back up capacity. Again, this trend strengthens over time, i.e. as the volume of DG-RES

40 Please note that we are focusing on the year 2030 since the situation in 2020 (and 2025) is still strongly influenced by the present structure of installed generation capacity.

grows. As further discussed in Section 4.5.1 we believe that this trend is caused by a shift in production from offshore wind to solar PV, or a decreasing contribution from offshore wind in general. This can be explained by the much lower capacity factors and the uncertain availability of solar PV and, to a lesser degree, onshore wind power in comparison with offshore wind. As a result, there may not only be an increased risk of insufficient energy being available from variable RES-E but it may also be less economic to mitigate this issue through transmission expansion. Based on this interpretation, we emphasise that the increased need for back-up capacity in the DG scenarios mainly reflects the choice of a different RES-E technology (i.e. energy source) but is not directly related to the use of DG.

Figure 61 Back up capacity in the main scenarios and the variations of scenario 1

Figure 62 reveals that a delayed expansion of transmission infrastructure leads to an increased need for back up capacities in Scenarios 1 and 1-DG and are even higher in the sensitivity with no transmission expansion post 2020. This development shows that transmission helps to maintain reliability by allowing the corresponding regions to import electricity from other locations at times of insufficient supply from variable RES-E.

Conversely, Figure 62 also shows that the need for back-up capacity would be significantly smaller if the power system has access to demand response. Compared to the basic scenario, the need for back-up capacity is reduced by some 30%, highlighting a considerable savings potential.

Similarly, the load-driven scenario requires less back up capacity than either Scenario 1-DG or the original Scenario 1, although it is based on the same share of electricity production and has the same level of DG-RES as Scenario 1-DG. In line with the underlying rationale for construction of this scenario, these results therefore seem to represent the benefits of a more balanced regional distribution of RES-E, which avoids major concentrations of capacity in region with (relatively) less demand.

In contrast, the need for back up capacity substantially increases in the sensitivity with additional heat pumps and electric vehicles (HP/EV). We believe that this result reflects the higher peak load in this particular sensitivity, which requires additional back up capacity to supply demand at times of limited production from variable RES-E. Please note that this result reflects the situation without using the flexibility of shifting the load from the applications, but that the outcome may be quite different when also using the DR potential available from these sources (see Section 6.2.4).

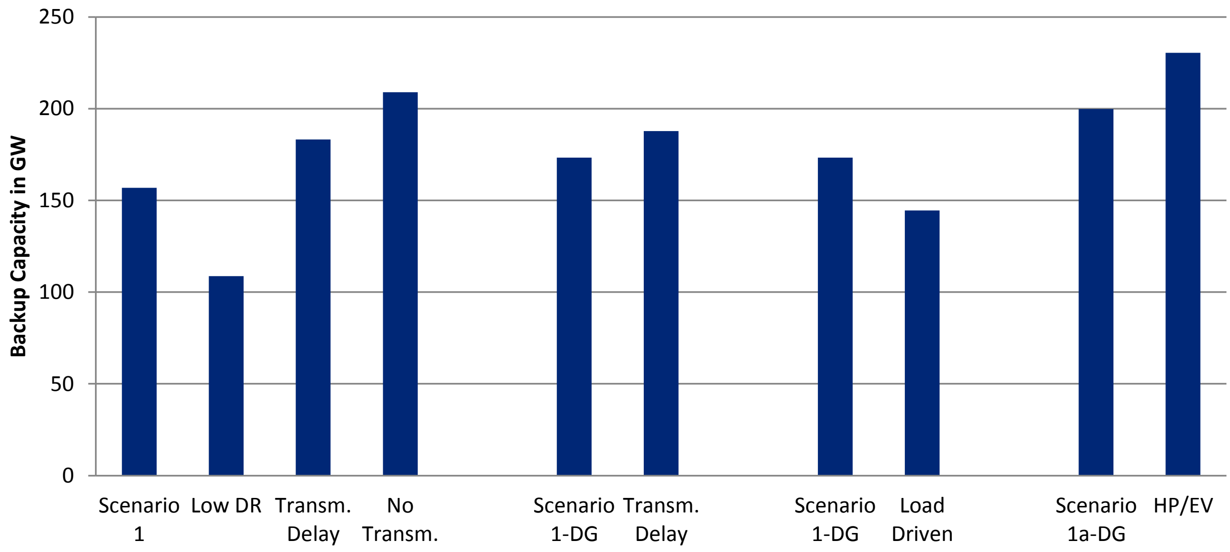


Figure 62 Back up capacity in the sensitivities of scenario 1 (2030)

Besides the overall level of back up capacity, its regional distribution across the EU-28 is of interest as well. Figure 63 presents the regional distribution of back up capacity in 2030 for the three main scenarios (left pattern) and the variations of scenario 1 (right pattern).

This figure leads to the following observations:

- Back up capacities are concentrated in Western Europe, i.e. in those Member States with a large of (offshore) wind power; and
- Although the need for back up capacity generally increases in the scenario with an increased penetration of DG-RES, there is no clear relation with the regional distribution of solar PV, as illustrated by the example of Great Britain.

To start with, the highest amounts of back up capacity are built in France (approx. 44 GW in scenario 1) and Great Britain (approx. 35 GW), followed by regions like Germany, BeNeLux, Spain and Ireland as well as Italy. All of these countries are characterised by large volumes of either on- or offshore wind power. In addition, it is worth noting that the need for back up generally seems to be higher in regions towards the periphery of the European electricity market, but lower in Central Europe, as illustrated for instance by the example of Germany which is well interconnected with several other countries.

Against this background, it is surprising to see that there is no clear relation between the need for additional back up capacities and the regional distribution of solar PV in the variations of scenario 1 with an increased penetration of DG. Although Figure 63 does show additional back up capacity in for instance France, Germany, Italy and Spain, the additional volumes remain limited. Moreover, we also observe a need for additional back up capacity in Great Britain, which has a substantially lower penetration of solar PV.

As further discussed in Section 4.7 it seems that these effects reflect the interaction between transmission expansion and the need for ensuring reliability at each location. We therefore refer to Section 4.7 for further interpretation of these results.

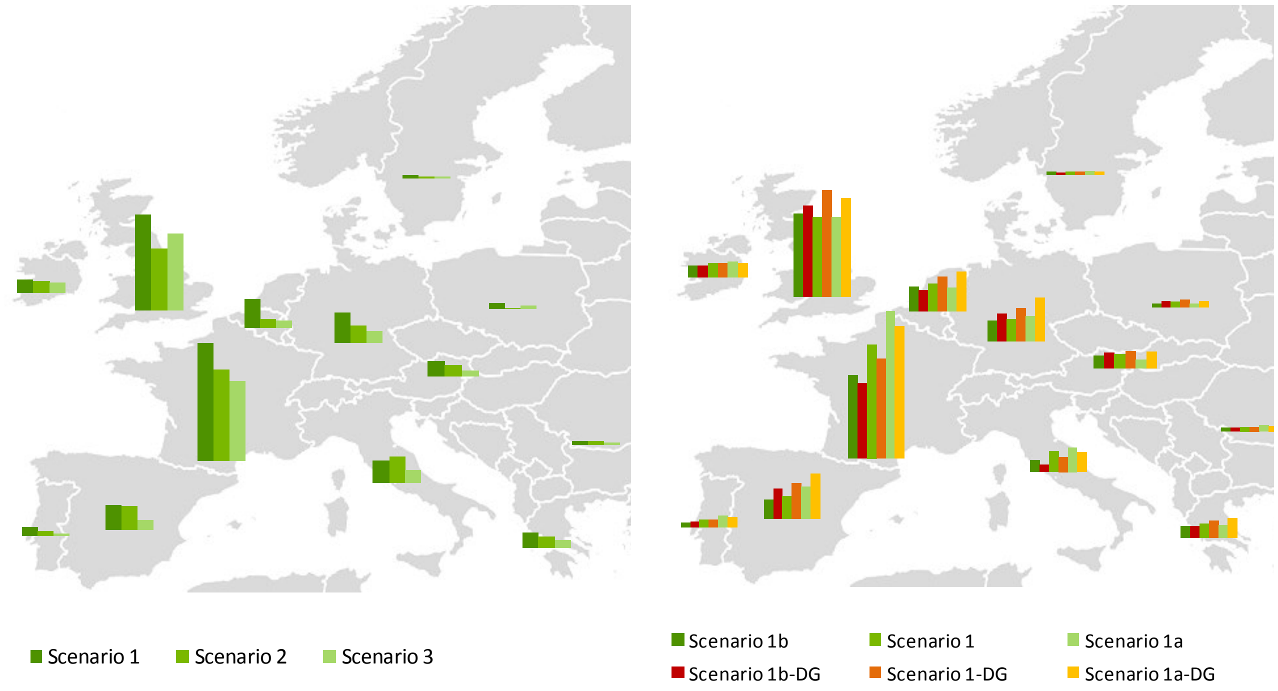


Figure 63 Regional distribution of back up capacity in the main scenarios (left) and the variations of scenario 1 (right) in the year 2030

4.3 Investments into Transmission Grids

On the basis of the RES-E capacity expansion we have analysed the optimal expansion of the European transmission grids in order to accommodate different levels of RES-E at the lowest possible cost. This Section first presents the corresponding impacts in terms of grid transfer capability and changes to the topology of the European transmission grid. At the end of this Section, we furthermore provide an overview of associated investments and costs.

Figure 64 shows the development of total grid transfer capability (GTC) in the three main scenarios. By definition, no additional transmission capacity is required in 2020 since our assumptions are based on the investment plans set out in the Ten-Year Network Development Plan (TYNDP) developed by ENTSO-E. Consequently, the model optimizes transmission capacity requirements beyond 2020 only.

A comparison of the three main scenarios in Figure 64 shows that:

- The need for transmission expansion is significantly higher in scenarios with an increasing penetration of variable RES-E; and
- All three scenarios show a significant expansion of the European transmission grids already in both 2025 and 2030.

The model results show that investments into additional transmission infrastructure generally increase over time, i.e. as the penetration of variable RES-E grows. Moreover, Scenario 1 with a high share of RES-E requires significantly more transmission network investments than Scenarios 2 and 3. Indeed, GTC effectively doubles from 2020 to 2030 in scenario 1, i.e. it increases from approx. 87,000 GW-km in 2020 to almost 170,000 GW-km in 2030. Conversely, the requirements are lowest in Scenario 3, which also has the lowest share of RES-E. Still, an additional grid transfer capability of almost 48,000 GW-km is required by 2030, representing an increase of approx. 55% compared to 2020. The results of Scenario 2 finally are between these two extremes, with a grid expansion of some 58,600 GW-km, reflecting an increase of 67% compared to the 2020 capability.

These results indicate that significant benefits can be achieved by reinforcing the European transmission grids, and that the need for transmission expansion grows with an increasing penetration of variable RES-E. However, it is worth noting that a significant expansion of the European transmission grids can already be observed for scenario 3 in the year 2025, which represents the lowest penetration of variable RES-E among the scenarios with optimised transmission expansion. This indicates that transmission expansion may not only be driven by the growing penetration of variable RES-E. Instead, at least some part of the additional transmission capacity may also serve to benefit from regional diversity and hence increase the efficiency of the 'existing' power system.

Strictly speaking, these results should therefore be interpreted as reflecting the benefits of increased transmission rather than an absolute need for additional transmission capacity. Hence, whilst the results clearly indicate that an increasing penetration of RES-E can be facilitated or may even require additional network capacity, not all of the additional transmission capacity may be absolutely required. We further explore this aspect below in the context of the sensitivities with reduced transmission expansion.

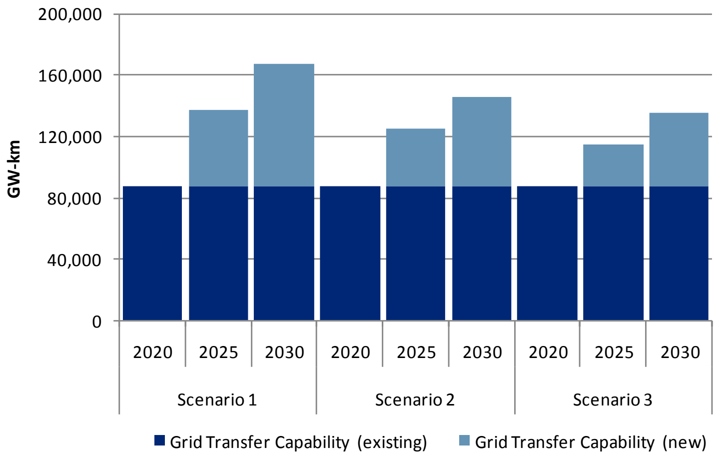


Figure 64 Development of Grid Transfer Capability in the main scenarios in the period 2020 to 2030

Figure 65 shows the modelling results regarding additional transmission capacity requirements in the year 2030 for the variations of scenario 1[41]. When comparing the three different variations of scenario 1, i.e. scenarios 1b, 1 and 1a, we observe an increasing volume of transmission expansion from scenario 1b (lowest) to scenario 1a (highest.) In direct comparison, scenario 1a requires about 20,000 GW-km (or 25%) more transmission expansion than scenario 1b. We note that this effect coincides both with increasing electricity demand and a growing penetration of RES-E in absolute terms. This seems to confirm our earlier observation that the absolute volume of variable RES-E seems to be a major driver for transmission expansion.

41 The results show a very similar level of transmission expansion in 2025.

When comparing the scenarios with a more centralised or decentralised generation structure, the need for transmission expansion remains virtually unchanged. Whilst total GTC slightly decreases in scenario 1b-DG, transmission expansion actually increases in scenarios 1-DG and 1a-DG. This observation may appear surprising on first sight as it is often assumed that decentralised generation will by definition reduce the need for network expansion. The view that DG will naturally reduce the need for network expansion is implicitly based on the assumption that decentralised generation will always be located close to consumption and that it will mainly reduce residual net consumption locally. Under these circumstances, DG can indeed help to reduce the need for network expansion as also illustrated by the results of the distribution analysis (see discussion on p. 70 ff. in Section 4.4 below) or the load-driven scenario as subsequently discussed below. It is therefore important to also consider the specific assumptions underlying the DG scenarios in this study.

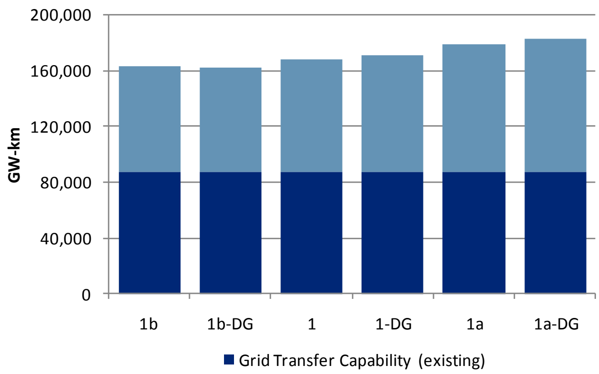


Figure 65 Grid transfer capability for the variations of Scenario 1 in the year 2030

As explained in the context of the load-driven scenario the regional distribution of RES-E in the PRIMES scenarios is mainly driven by resource availability. Besides the location of offshore wind power in the centralised scenarios, this also applies to the regional distribution of solar power in the decentralised scenarios. As a consequence, an over-proportional share of solar power is installed in Southern Europe, resulting in the need of exporting excess electricity to other regions. This effect is further aggravated by the assumption that solar power will be generally based on the use of PV panels, which are characterised by a relatively low capacity factor. The use of solar PV thus increases the need for exports of temporary exports, for instance during sunny days in the spring or autumn, even if local consumers still need additional supply of electricity at other times.

In this context, it is furthermore interesting to consider the impact which the different sensitivities of Scenario 1 have on the need for transmission grid expansion (compare Figure 66). Figure 66 shows that the load-driven scenario leads to a significant reduction in incremental transmission capacity. This reflects the fact that the load-driven scenario was specifically designed with the aim of a more balancing regional distribution of wind and solar power, i.e. with a more local production structure (see Section 3.4.1). The load-driven scenario thus confirms that DG may indeed help to reduce the need for network expansion. In addition, it also requires less back up capacity (compare Figure 62 on p. 58) such that it more generally requires less additional infrastructure to integrate the same penetration of RES-E as the centralised scenarios 1 and 1-DG. However, as the need for additional network capacity in scenario 1-DG shows, it is not the use of DG in general, which allows reducing the need for network infrastructure, but rather the specific choice and distribution of different decentralised technologies. These considerations highlight the impact, which two major design parameters, i.e. the choice of technologies and the regional distribution of RES-E, may have on the cost of system integration.

Although DR also allows for a reduction of transmission expansion, the impact is much smaller and remains of a largely marginal nature, i.e. less than 5% in terms of transfer capability as well as costs. This limited effect can probably be explained by the fact that transmission expansion is primarily driven by differences in resource availability, whereas DR mainly helps to mitigate the impact of short-term variations. In principle, it might be possible to achieve a further reduction in infrastructure needs by adjusting the geographical distribution of DR in accordance with the system's needs. This, however, has not been further investigated in this study and would furthermore require strong locational signals and/or other regulatory interventions, in order to steer the geographical distribution of DR.

Figure 66 also shows that an increased use of heat pumps and EVs (without load management) requires additional reinforcements of transmission systems. This result emphasises that the need for transmission expansion is not only driven by RES-E but equally by potential developments on the demand side. However, it should be noted that these results do not consider the potential benefits of demand response or decentralised storage; these aspects are discussed in more detail in Sections 6.2.4 and 6.2.2, respectively.

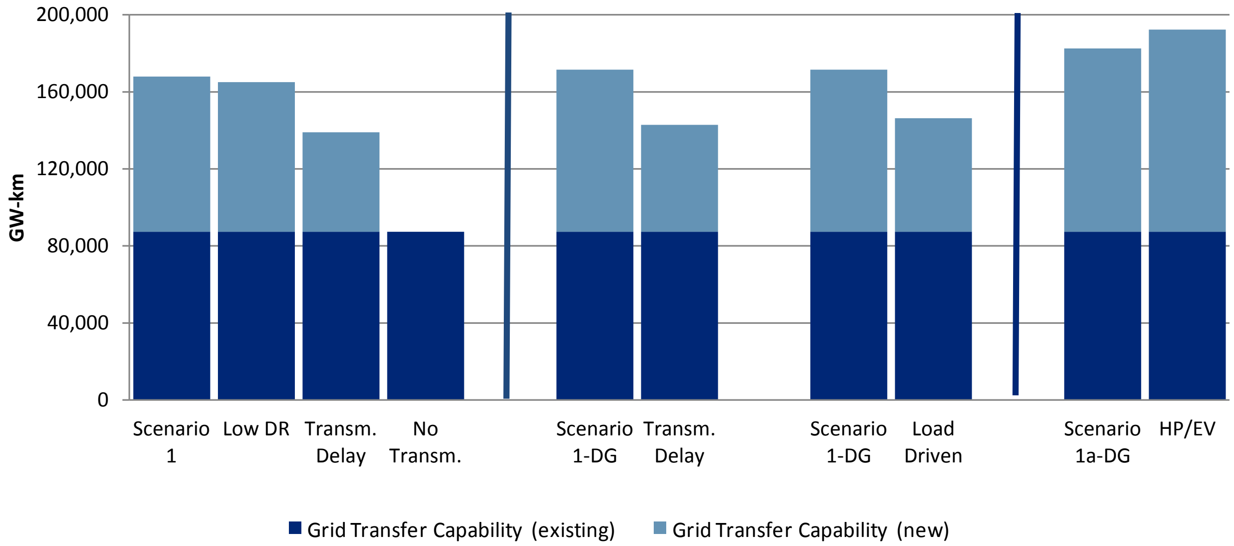


Figure 66 Grid transfer capability for sensitivities of Scenario 1 in 2030

Figure 67 and Figure 68 show the structure of the optimised transmission grid in the year 2030 in scenarios 1, 2 and 3. Each figure indicates both the existing grid transfer capability in the year 2020 as well as additional reinforcements until the year 2030.

These two figures reveal that most of the additional transmission capacity is located in few corridors linking in particular those regions with a high penetration of wind power, i.e. Scotland, Denmark / Northern Germany, BeNeLux, France, Spain and Italy. All scenarios furthermore result in additional capacity between Great Britain and Norway, allowing the former to benefit from the flexibility of Norwegian hydropower.

In Scenario 1, which has the highest share of RES-E, these network reinforcements effectively result in a large 'transmission loop' from Northern Germany via South-Western Europe to Italy and back to Northern Germany, and two radial connections from Northern Germany to Northern Sweden and from France to Great Britain (and further to Norway).

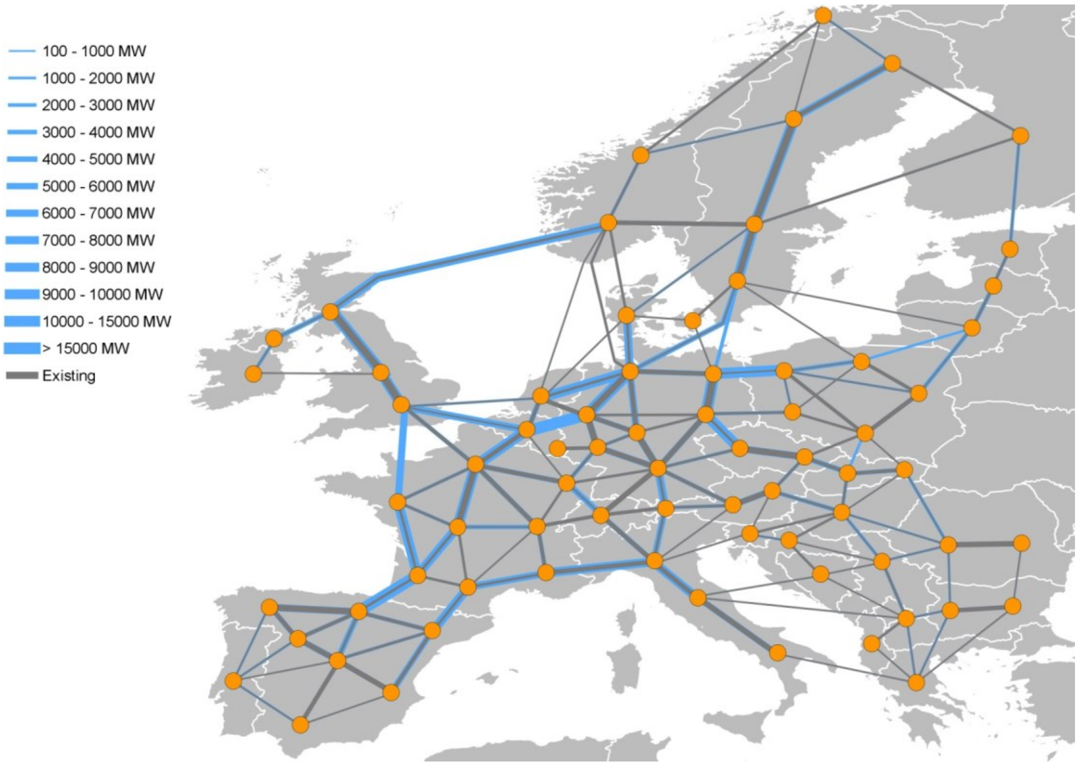
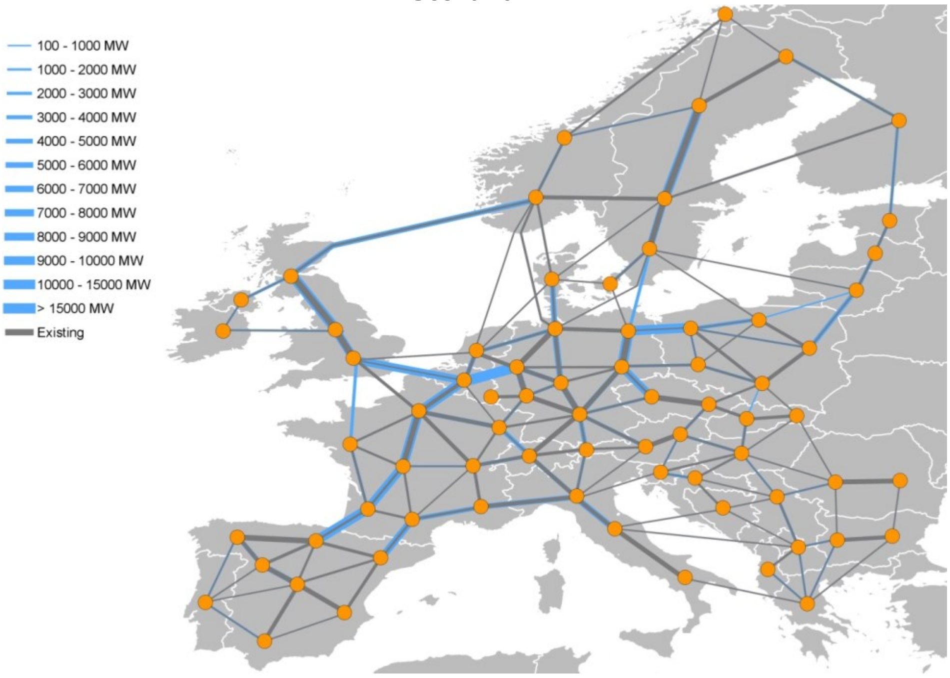


Figure 67 Existing and final transmission capacity in Scenario 1 (2030)

Scenario 2 (Figure 68) shows a similar pattern as scenario 1, but with generally lower transmission expansion. The same trend can principally be observed for scenario 3, except for a few isolated connections (such as from Serbia to Hungary).

Scenario 2



Scenario 3

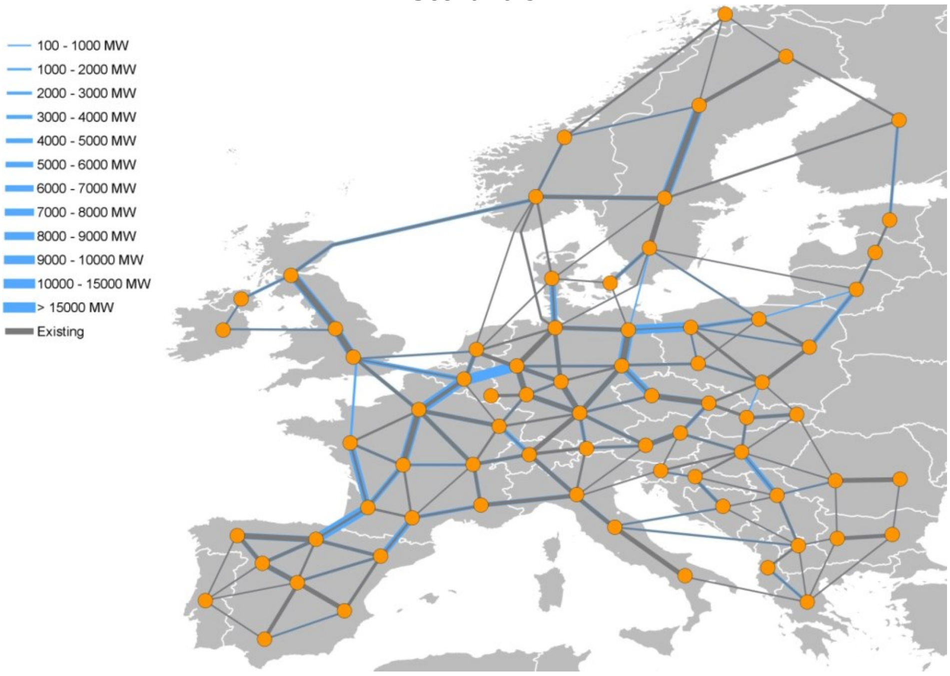


Figure 68 Existing and final transmission capacity in Scenarios 2 and 3 (2030)

Figure 71 shows the same view for Scenarios 1a and 1b. In principle, both Scenarios reveal a similar pattern of transmission expansion as Scenario 1, although the overall level of interconnection is slightly higher and lower in Scenario 1a and 1b, respectively. When neglecting some other minor changes, these variations thus seem to broadly reflect the different penetration of variable RES-E in the three different scenarios.

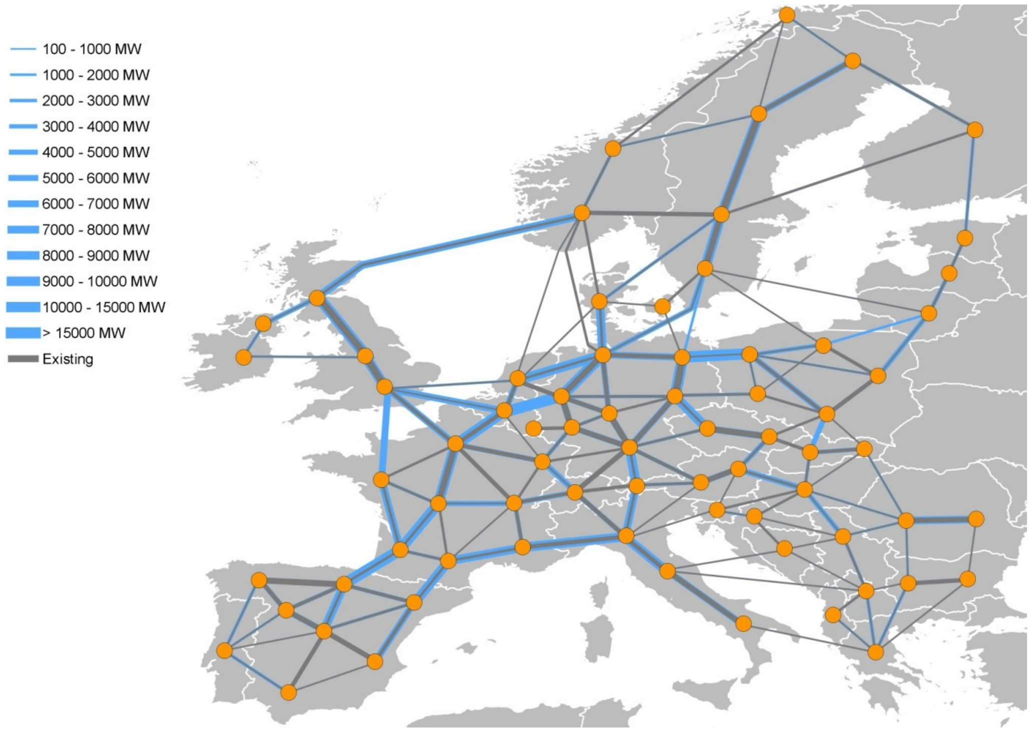


Figure 69 Existing and final transmission capacity in Scenario 1a (2030)

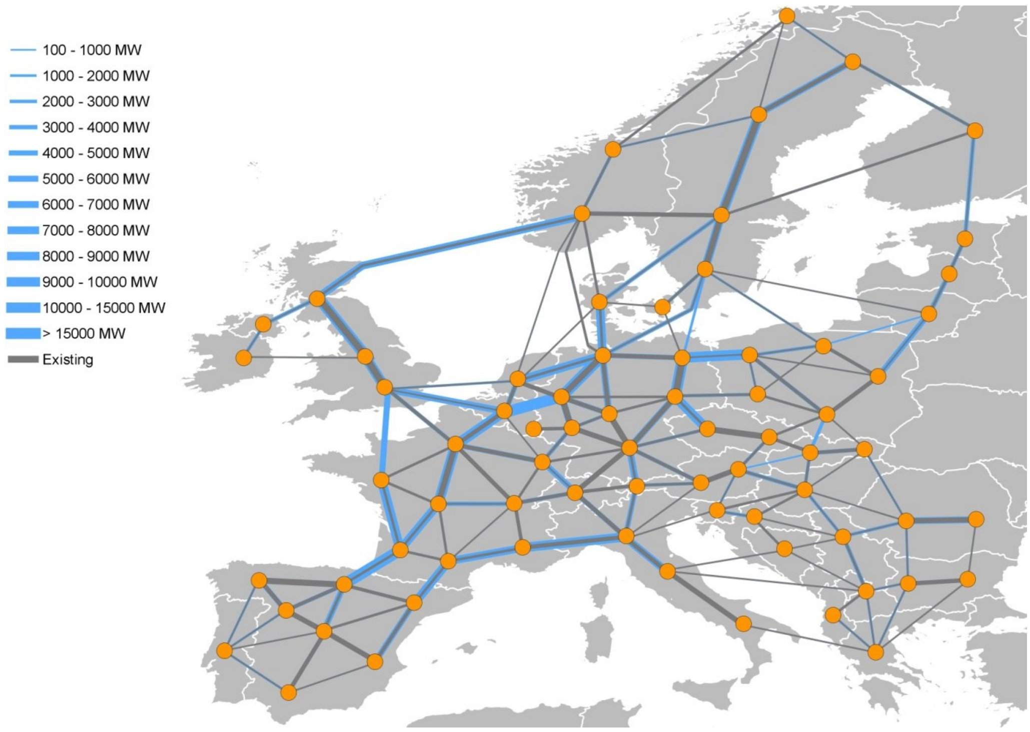


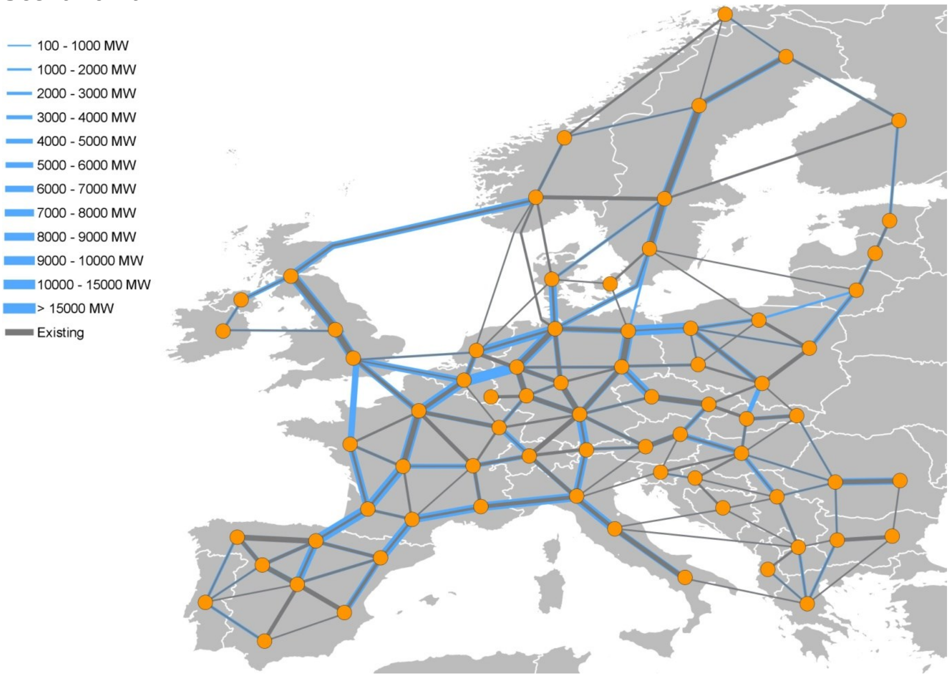
Figure 70 Existing and final transmission capacity in Scenario 1b (2030)

Figure 71 compares the optimised transmission grid in two variations of Scenario 1a with a more centralised and decentralised generation structure, i.e. Scenarios 1a and 1a-DG. Despite a similar general structure, the second variation with a higher share of decentralised generation leads to the following changes:

- A further strengthening of the transmission corridors between Spain and Italy, Spain and Great Britain, and between Northern Italy and (Northern) Germany;
- The extension of the link between Northern and Southern Italy; and
- A more limited expansion of the interconnector between Scotland and Norway.

These changes effectively result in a further strengthening of the links between the major centres of wind and solar power in (Western) Europe, whereas changes in other parts of Europe remain limited. Similar trends can also be observed for the other variations of Scenario 1, i.e. between Scenarios 1 and 1-DG as well as between Scenarios 1b and 1b-DG.

Scenario 1a



Scenario 1a-DG

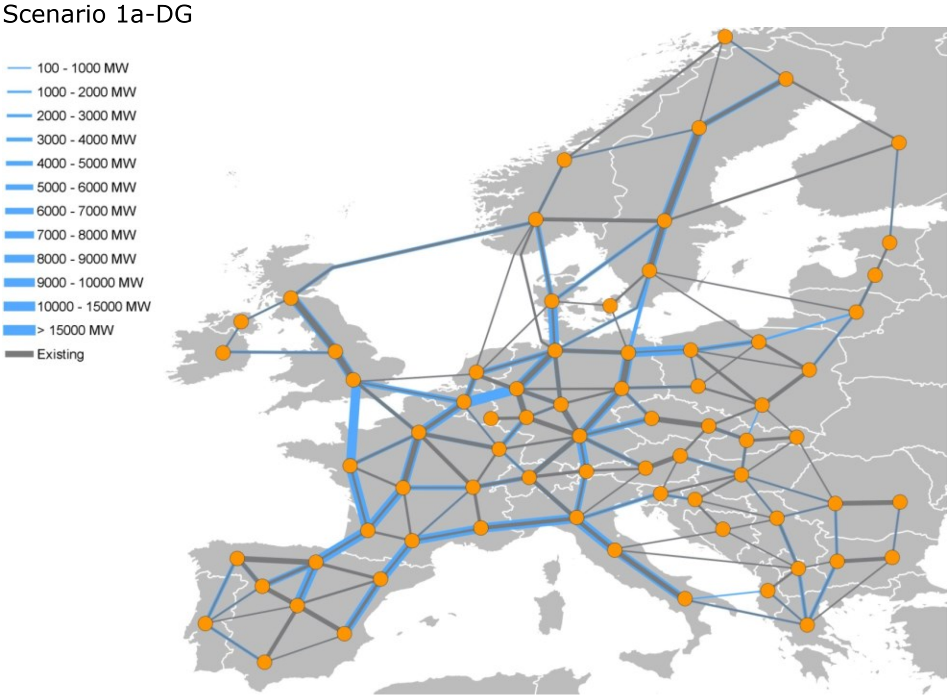


Figure 71 Existing and final transmission capacity in Scenarios 1a and 1a-DG (2030)

Figure 72 shows the results of the load-driven scenario. A comparison with Figure 67 reveals some interesting differences with the outcome of Scenario 1. Figure 72 again shows that the load-driven scenario requires less transmission expansion than the original Scenario 1 or the corresponding variation with an increased share of decentralised generation (1-DG). Secondly, most of the reduction is achieved by either avoiding or reducing expansion in certain corridors that were required in the original scenario(s). Among others, this applies to the connection between Scotland and Norway, between North-

Western Germany and the Netherlands, between Northern Germany and Italy, and between Spain and Italy. In contrast, there is hardly any need for additional transmission capacity in the load-driven scenario, except for a new connection between Italy and Albania or the reinforcement of the interconnector between Sweden and Poland. To a large extent, these changes seem to reflect the major reduction of offshore wind in more peripheral areas around the North Sea. Conversely, it appears to be much easier to integrate the additional volumes of biomass and onshore wind power in Central and Eastern Europe.

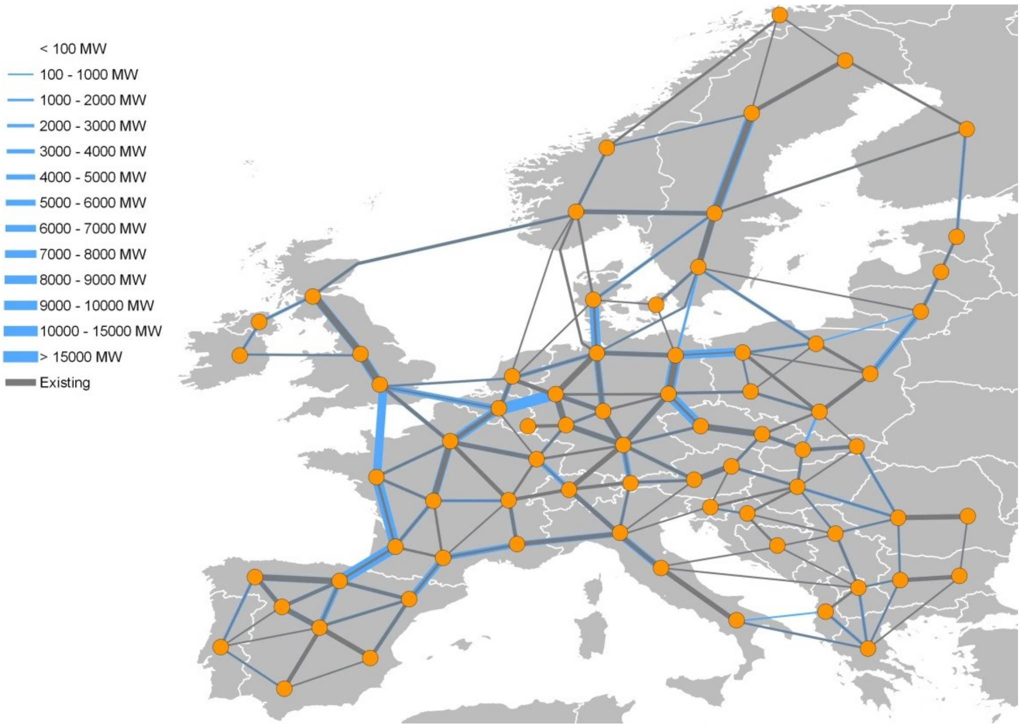


Figure 72 Existing and final transmission capacity in the load-driven sensitivity (2030)

Figure 73 presents a summary of the cumulative (annualised) costs associated with investments into the European transmission grids. The variations between the individual scenarios broadly reflect the differences in transmission expansion as presented above. Annualised cost for Scenario 1 amount to approx. € 4bn in 2030, compared with approx. € 2.8bn for Scenario 2 and € 2.2bn for Scenario 3. Similarly, annualised costs vary between less than € 4bn and almost € 5bn in the variations of Scenario 1. Depending on the scenario, cumulative investments until the year 2030 thus vary between slightly more than € 20 billion and nearly € 50 billion.

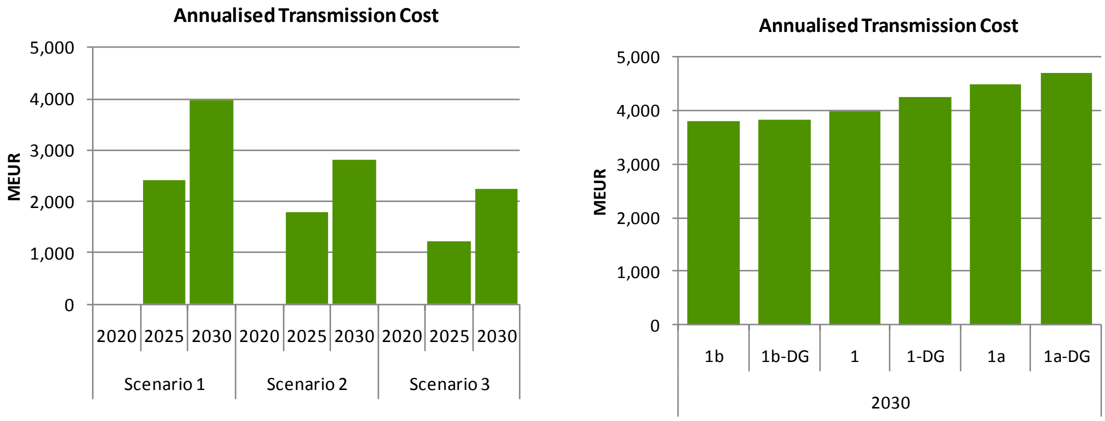


Figure 73 Annualised costs of cumulative additional transmission capacity for the main scenarios (1, 2, 3) and the variations of Scenario 1 (EU-28, in MEUR)

4.4 Investments into Distribution Networks

Based on the methodology presented in Section 2.3, we have determined the need for expansion and reinforcement of the European distribution networks in the time period until the year 2030. The expansion needs were projected for the years 2020, 2025 and 2030 and represent snapshots of these target years. This means that the resulting distribution reinforcement costs of the distribution model presented below show the cumulative investment needs compared to the initial year (2010).

Figure 74 shows the cumulative cost of distribution reinforcements in the main scenarios. In the year 2020, cumulative costs reach around € 170bn in all three scenarios. Between 2020 and 2025, they increase to some € 215bn but remain fairly stable afterwards. Moreover, it is interesting to note that the three main scenarios lead to very similar cost levels. For instance the cumulative costs of Scenario 1 exceed those of Scenario 3 by less than € 10bn, which is less than 5% of the total.

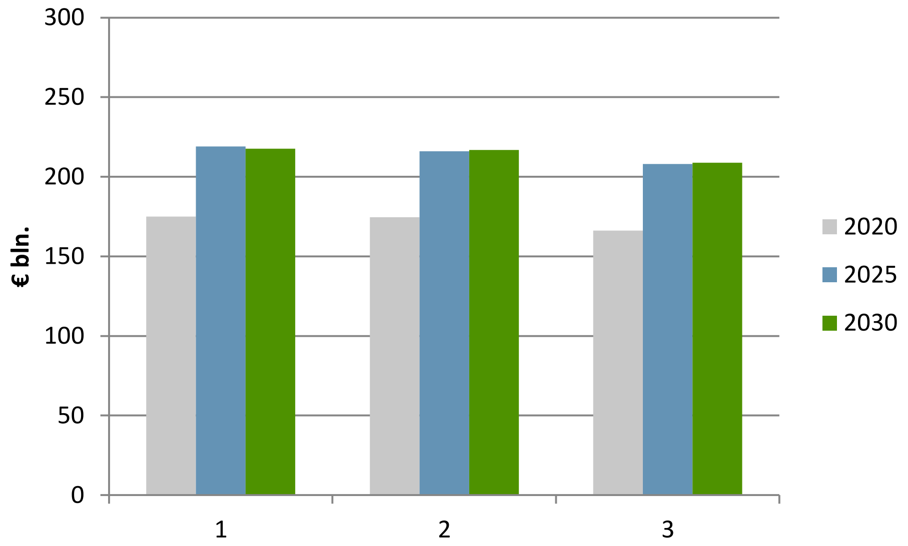


Figure 74 Cumulative distribution reinforcement costs in the main scenarios (EU-28, in EUR bn)

Figure 75 shows the cumulative costs of distribution grid enforcements for the variations of Scenario 1. The corresponding numbers show a wider range than those presented in Figure 74, with a minimum of € 80bn in 2020 and a maximum of € 270bn in the year 2030.

Figure 75 renders the following observations:

- Costs generally increase between 2020 and 2030, but remain at the same level for scenario 1b. Moreover, costs remain stable after 2025 in scenarios 1 and 1-DG, whilst they continue to increase at least in the decentralised variations of scenarios 1b and 1a.
- The largest differences can be observed between three basic variations, i.e. scenarios 1b, 1 and 1a. In contrast, differences between scenarios with and without a larger share DG tend to be smaller at least in the years 2025 and 2030.
- A larger share of DG initially helps to reduce cost in scenarios 1b and 1a, but this difference disappears in the years 2025 and 2030.
- Although scenarios with an increasing penetration of DG lead to higher costs in 2030, these differences remain marginal.

Overall, the results presented in Figure 75 remain inconclusive with regards to the impact of decentralised generation on the need for distribution reinforcements. Indeed, it appears that distribution network expansion requirements may be primarily driven by increasing load rather than by an increasing penetration of DG-RES.

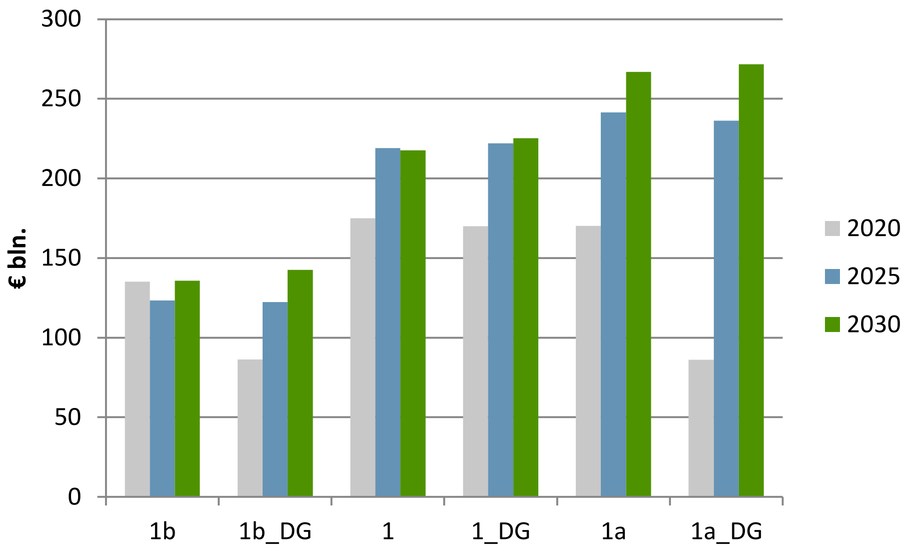


Figure 75 Estimated cumulative cost of distribution expansion in the variations of Scenario 1 (EU-28, EUR bn)

To better understand the corresponding effects, Figure 76 presents a more detailed analysis of scenarios 1 and 1-DG. More specifically, Figure 76 covers the following three cases:

- With additional DG but without any load growth from 2012 to 2030 ("no load growth");
- With load growth but without any growth of DG after 2012 ("w/o DG"); and
- With load growth and additional DG as defined for each scenario ("w DG").

To start with, Figure 76 shows that an isolated growth of either load or DG requires an expansion of existing distribution networks. In the first case, distribution expansion is driven by the need of connecting additional consumption, which increases substantially from approx. 2,800 TWh in 2010 to almost 3,250 TWh in 2025 but stagnates thereafter (compare Section 3.2.1). As the columns in the centre of Figure 76 show, load growth alone requires cumulative investments of approx. € 225bn by 2025. Similarly, an isolated growth of DG also requires network reinforcements. Although cumulative investments remain at a much lower level of approx. € 75bn by 2025, these results nevertheless confirm that installation of DG may require an expansion of existing distribution networks. However, it is interesting to note that the difference between the centralised and decentralised scenario remains very small. Moreover, when combining both effects, cumulative costs are slightly lower than without DG. This seems to indicate that DG helps to avoid load-driven distribution expansion. Overall, these results remain inconclusive with regards to the impact of DG; i.e. whilst it clearly causes additional costs in some cases, it may also have a cost-decreasing effect in other cases.

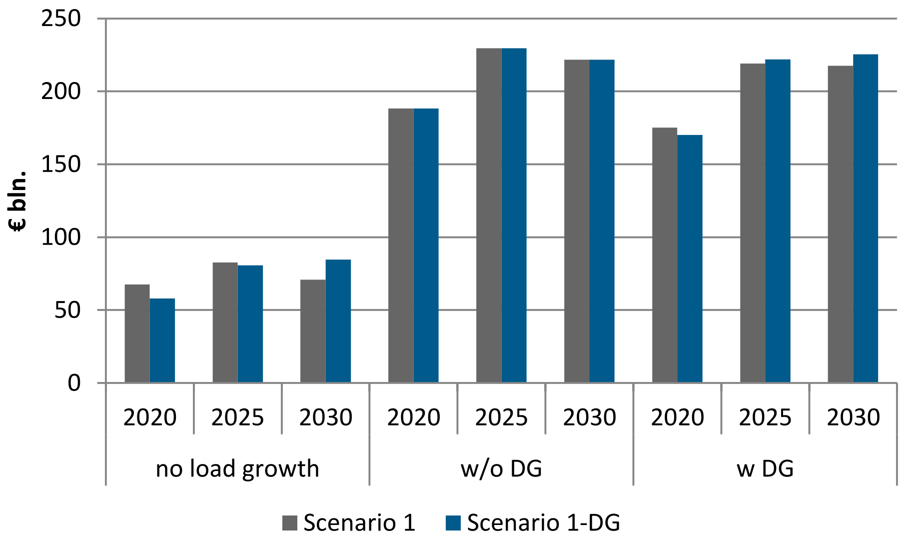


Figure 76 Exemplary comparison of DG and load-driven reinforcement costs (EU-28, cumulative, in EUR bn)

Note: "w/o DG" – scenario with load growth but without DG; "w DG" – scenario with load growth and DG

To further assess the corresponding relations, Figure 77 provides another comparison for the example of Germany. Germany represents an interesting case as it combines a high concentration of DG-RES (mainly solar PV) with ambitious energy efficiency measures, i.e. with very limited load growth until the year 2030. Figure 77 covers the following cases:

- Two scenarios without load growth but with an increasing penetration of DG; shown on the left of Figure 77;
- One scenario with load growth but without any additional DG; shown in the centre of Figure 77;
- Two scenarios with load growth and an increasing penetration of DG; shown on the right of Figure 77.

A comparison of the first two scenarios clearly illustrates that a growing penetration of DG requires increasing distribution reinforcements. Indeed, the need for distribution reinforcements grows over time, i.e. in parallel with the growing share of DG, but is also considerably higher in the second scenario with a substantially higher penetration of DG. The same effect is also visible when comparing the central scenario and the two scenarios on the right. Again, higher penetrations of DG clearly increase the need for distribution expansion. Overall, a high share of DG-RES causes additional costs of at least € 15 bn in the year 2030[42].

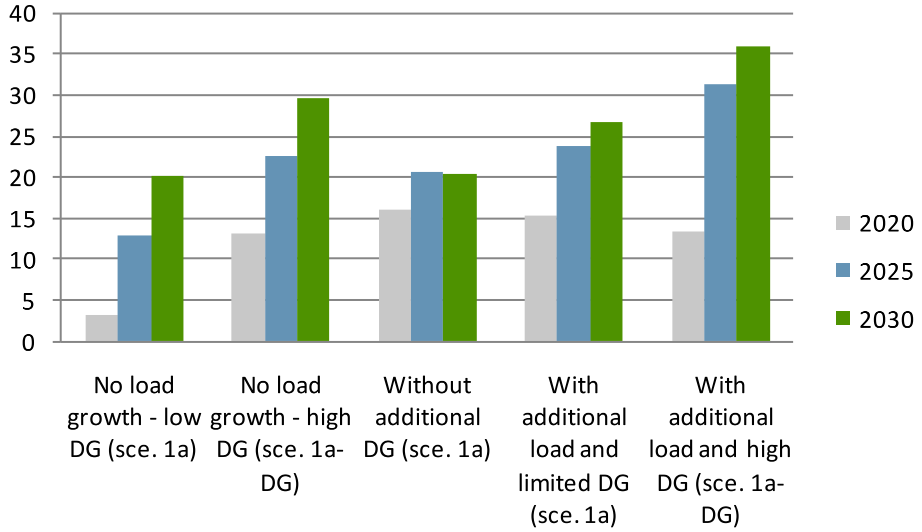


Figure 77 Impact of DG-RES and load growth on cumulative distribution reinforcement costs in Germany (EU-28, in EUR bn)

Secondly, Figure 77 again shows that a limited level of decentralised generation may initially help to reduce the need for network extensions, but that this trend reverses as the penetration of DG increases. This effect can best be seen in the year 2020 where the combination of load growth and additional DG leads to lower costs than isolated load growth in the central scenario.

Thirdly, Figure 77 also shows that it is not possible to simply sum up the impact of different effects. Indeed, the combined impact of load growth and additional DG-RES is significantly smaller than the sum of the individual values for all possible combinations shown in Figure 77. More specifically, the costs of an isolated growth of DG or load amount to approx. € 30bn and € 20bn, respectively. In contrast, the combination of both effects requires cumulative investments of approx. € 35 bn, which is 30% less than the sum of the individual amounts. This also indicates that the need for distribution always has to be seen in the context of the overall development on the supply and demand side, whilst an isolated analysis may lead to misleading interpretations.

To better understand these observations, it is useful to consider the possible interaction between demand and different types of DG:

- Ceteris paribus, DG initially replaces existing demand and thereby reduces the utilisation of the given voltage level as well as the offtake from higher voltage levels. To the extent that the production profile of DG helps to reduce local peak load in a reliable way, DG may thus increase the effective headroom of the existing network and allow delaying future network expansion, which is required in case of load growth.
- As the penetration of DG grows, this will increasingly lead to backfeed situations where production by DG exceeds local demand. This will lead to a reversal of load flows in the network since electric power starts flowing from lower voltage levels to higher voltage networks, and ultimately up to the

42 Based on the difference between the total costs of the scenario with load growth and a high share of DG on the right (€ 35 bn) and the central scenario without additional DG (approx. € 20 bn).

transmission grid. Depending on the aggregate capacity and production profile of DG, this will ultimately require an expansion of the existing grid, i.e. once reverse flows exceed the transport capability of the local network.

The point at which DG will lead to either decreasing or increasing costs depends on a number of different factors, including existing headroom in the distribution network, the load profile of local demand, as well as the production profile of DG. As further discussed on pp. 76 below, the latter aspect is furthermore strongly related to the type of DG, i.e. to which extent the DG output profile can be controlled or not.

In addition, it is worth noting that the need for distribution expansion may be caused by two different effects, namely:

- Thermal constraints, i.e. electrical energy flows in excess of the installed capacity of different types of equipment, such as lines, cables or transformers; and
- Voltage violations.

In the second case, the capability of the installed equipment is still sufficient to transport the resulting load flows. However, for instance a growing infeed by DG may lead to voltage problems, i.e. in the form of violations of the voltage limits.

Figure 78 shows the level of voltage related reinforcement cost in the main scenarios and the variations of Scenario 1. A comparison with Figure 74 and Figure 75 shows that voltage driven investments represent a substantial share of total network reinforcement needs. Moreover, the need for voltage-driven network extensions shows a similar pattern as total cost. Indeed, voltage related reinforcements account for roughly 30% of total costs at the distribution level across all scenarios and years, but are slightly lower for the high-DG scenarios in the year 2030.

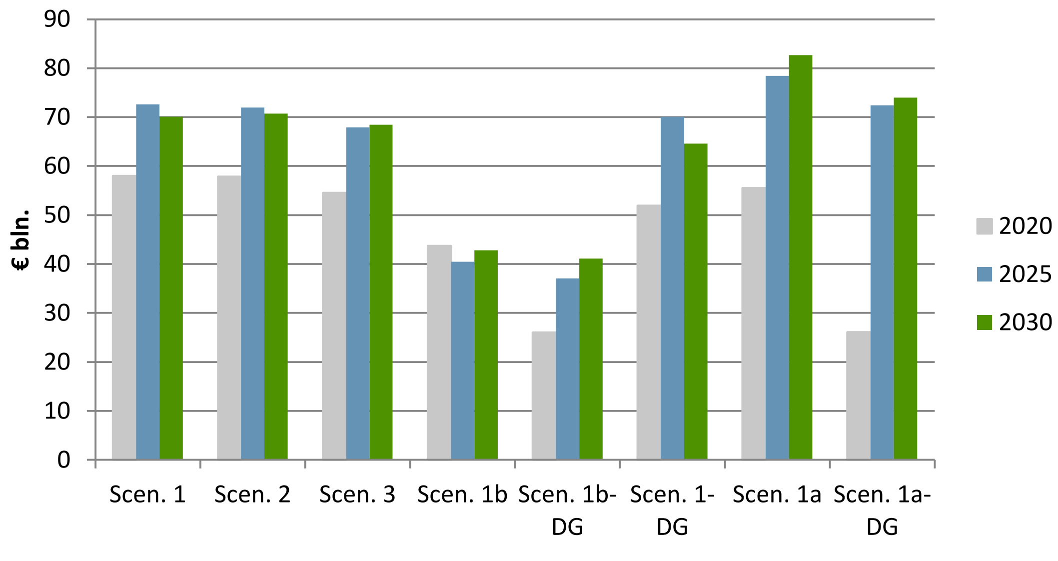


Figure 78 Voltage related reinforcement costs (EU-28, cumulative, in EUR bn)

Figure 79 takes a look at the distribution of total investment needs by voltage level for the main scenarios 1, 2 and 3. The comparison shows a common pattern regarding the distribution of costs between the voltages levels as well as common development over the years. Reinforcements at low voltage networks are the major driver of network reinforcements. For the main scenarios, they range from € 65bn to just above € 82bn, or roughly 40% of total costs. Conversely, the relative shares of reinforcements at the MV and HV levels, respectively, may vary more substantially, with less investments at the HV level especially for lower shares of DG in particular. On average, however, reinforcements at the HV level account for about one third of total cost, but MV networks for approx. one quarter.

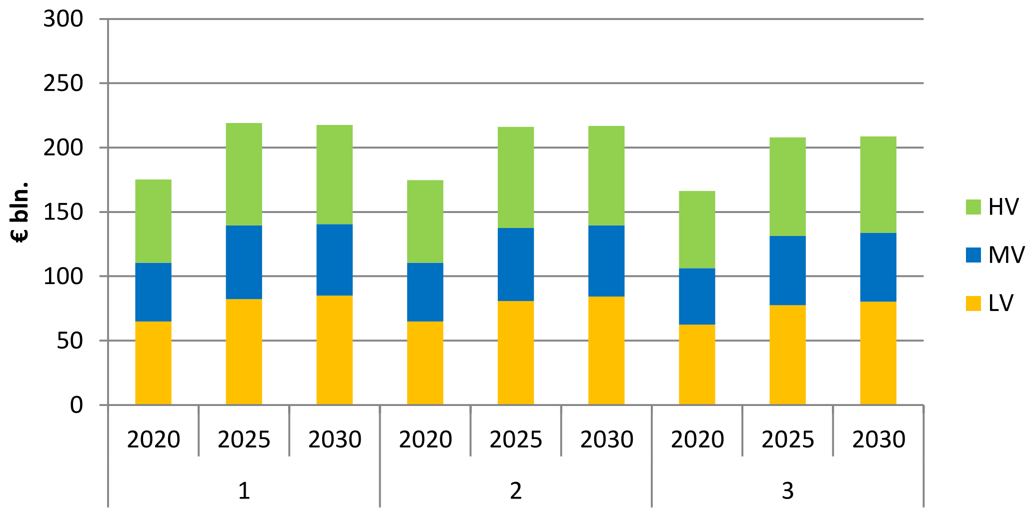


Figure 79 Cumulative distribution reinforcement cost by network level for the main scenarios (EU-28, in EUR bn)

Figure 80 breaks down voltage related reinforcement costs by voltage level. In contrast to total cost of distribution reinforcements (see Figure 79), low voltage networks account for a much larger share of voltage problems in the scenarios considered in this study. On average, about 60% of voltage-related costs occur in LV networks, compared to 40% of total costs. Conversely, voltage problems are much less prevalent in HV networks, such that they represent less than 10% of voltage-driven costs in Figure 80.

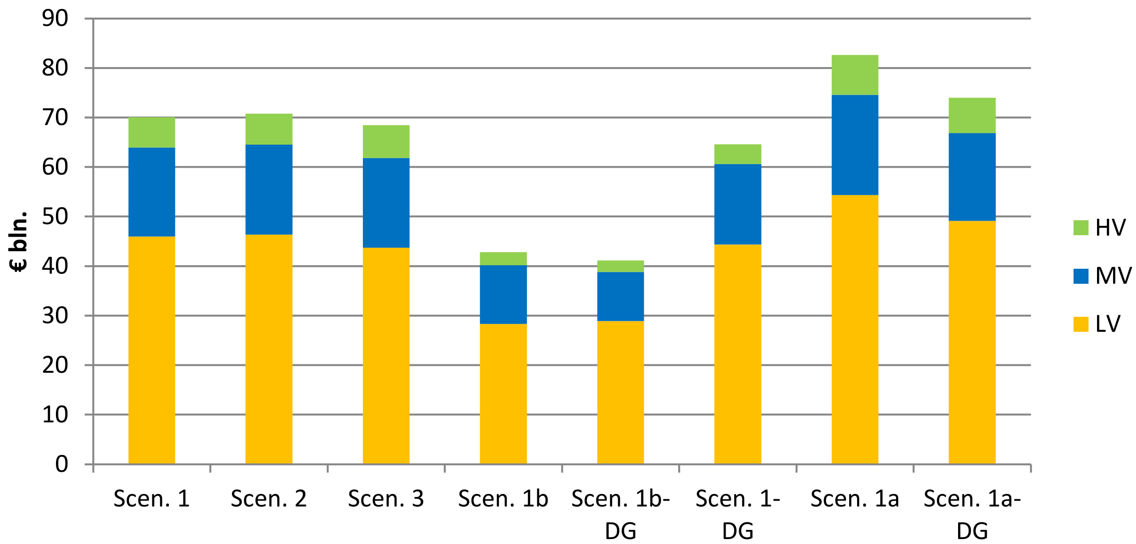


Figure 80 Cumulative voltage driven reinforcement cost by network voltage level for the main scenarios and the variations of Scenario 1 in 2030 (EU-28, in EUR bn)

These differences are important since there exist multiple ways for dealing with voltage problems (see Chapter 6), whilst thermal constraints generally require the replacement of existing assets. At the same time, it is important to note that the distribution of reinforcement needs over different voltage levels is strongly driven by the distribution of load and decentralised generation. For example, the scenarios presented in Chapter 3 generally assume that solar PV represents the main source of DG-RES, whereas we assume a limited level of onshore wind power to be connected at the distribution level. Furthermore, solar PV facilities are assumed to be mainly connected to LV networks.

Clearly, these assumptions may not always hold in practice. Among others, either the mix of DG-RES or the distribution of DG-RES across distribution voltage levels may be different from the assumptions underlying our analysis. For instance when assuming a higher share of larger PV installations that are connected to MV grids, the need for LV network expansion could be expected to be smaller than indicated by the numerical results. Although the connection of additional production facilities might require additional reinforcements of MV networks, these would probably remain limited in comparison to potential savings in LV networks. Conversely, if investment needs in LV grids were primarily driven by growing demand, the connection of solar PV to higher voltage levels could even result in the need for additional LV reinforcements. Given that load growth appears to be the main driver in most of the basic scenarios presented above, it is therefore difficult to estimate which of the two effects would be stronger. Nevertheless, these considerations clearly illustrate that the quantitative results presented in this Section are associated with considerable uncertainty. Indeed, even with the same overall share of DG, total costs as well the split of total costs by voltage level might therefore be different if different assumptions on the mix and size / connection level of DG were used.

We note that there also other aspects which may influence the need for distribution expansion. To assess the robustness of the simulation results, we have therefore tested the following sensitivities, which look at the influence of several selected aspects and input assumptions:

- Network design standards;
- Share of controllable DG;
- Distribution of DG-RES in LV networks;
- Demand response;
- Installation of heat pumps and electric vehicles.

Network Design Standards

The capability of distribution systems to absorb DG-capacity and load growth depends on these design standards. Distribution system operators design their networks based on experience and regulatory guidelines, which vary both across and partially within Member States. In our basic simulations, we have assumed that the minimum available capacity margin of existing MV/LV transformers in most countries is at least 15% of transformer capacity[43]. In a first sensitivity, we have increased this headroom to a minimum of 25%, which should make it easier for existing network to absorb additional consumption and DG.

Figure 81 shows that this sensitivity leads to an overall reduction of distribution reinforcement costs by around € 25bn or 11% of the original value. When considering reinforcements at the LV level only, total costs decrease by almost 25%. Whilst these numbers represent significant savings, they still remain

[43] We have used a higher headroom for countries like Germany and Austria, which have traditionally built in higher margins into distribution networks.

limited in comparison to total costs, confirming the general conclusions of our analysis. In addition, it is important to note that higher headroom in existing distribution networks implicitly assumes that additional investments have been made in the past. Consequently, total costs of distribution are likely to be higher than in our original assumptions.

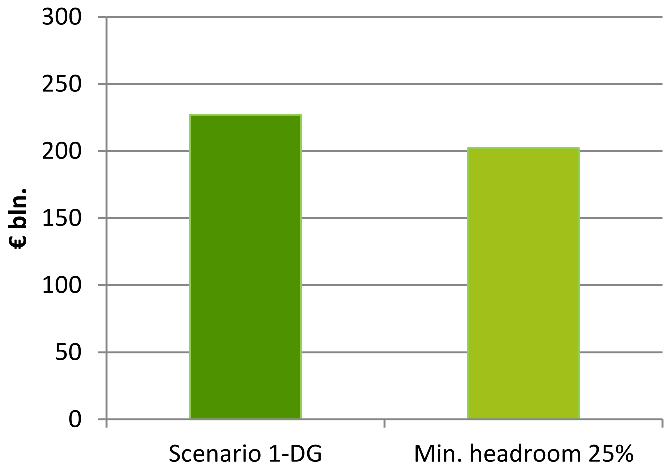


Figure 81 Comparison of cumulative distribution reinforcement cost with and without additional headroom for LV networks in 2030

Share of controllable DG

Apart from a strongly increased penetration of solar PV, the DG scenarios also include an increasing penetration of small decentralised cogeneration units, such as gas motors. In contrast to other DG technologies, small cogeneration units show a generation profile which is positively correlated with the demand profile for electricity. Moreover, small scale cogeneration can be controlled by the operator and offer firm capacity, irrespective of fluctuating weather conditions. As a result, small scale CHP may help to avoid network reinforcements.

In order to assess the effect of cogeneration units on distribution reinforcements, we have considered another sensitivity that does not include any generation by small scale CHP. Figure 82 illustrates the resulting costs of distribution reinforcement for Scenario 1, 1-DG and the sensitivity of 1-DG without small scale CHP. These results show that distribution reinforcement needs in scenario 1-DG would be significantly higher without small scale CHP, i.e. that cogeneration units have obviously helped to reduce the need for network extension. Conversely, the incremental costs of integrating fluctuating DG, such as wind and solar PV, now amount to around € 65bn in comparison with the original Scenario 1. Similarly, the integration of DG-RES without any load growth and without small scale CHPs causes additional costs of around € 85bn until the year 2030.

These findings indicate that the results discussed above may under-estimate the true cost of integrating DG-RES into European distribution networks. In addition, they highlight once again that the overall costs of distribution network reinforcements are driven by several different factors, and not the penetration of DG-RES alone.

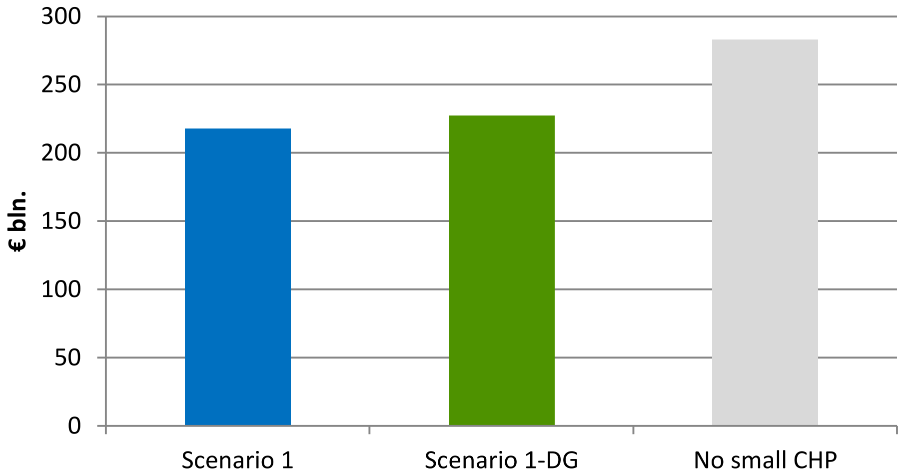


Figure 82 Impact of small scale CHP on cumulative distribution reinforcement costs in 2030 (EU-28, in EUR bn)

Distribution of DG-RES in LV Networks

Apart from design standards, the spatial distribution of DG can be expected to be another key factor for the need for distribution reinforcements. In addition to the basic scenarios, we have therefore analysed the following sensitivities with different assumptions for the distribution of solar PV capacity connected to LV networks:

1. Distribution of DG in different areas;
2. Location of solar PVs closer to the end of individual feeders (increasing density);
3. Location of solar PVs closer to the transformer at the start of individual feeders (decreasing density);
4. Varying spatial distribution of solar PV across individual feeders.

As explained in Chapter 2.3.3 we have assumed a certain distribution of DG to rural, suburban and urban areas in the different scenarios and sensitivities. Although we have not specifically varied the corresponding distributions, a comparison of the resulting need for distribution expansion in each of these areas still provides some interesting insights. For illustration, Figure 83 compares the cumulative reinforcement costs of each type of typical networks in Scenarios 1a and 1a-DG, i.e. the scenarios with the highest level of load growth and hence DG. This figure shows that the addition of DG leads to additional costs in rural areas, whereas costs are virtually unchanged in suburban areas and even decrease in urban areas. These differences indicate that it might be possible to reduce overall costs by reducing the share of DG in rural areas but shifting the corresponding capacities to urban areas[44].

[44] We acknowledge that the scope for corresponding changes may be limited for instance by the limited availability of the necessary space and/or higher costs for additional solar installations in urban areas.

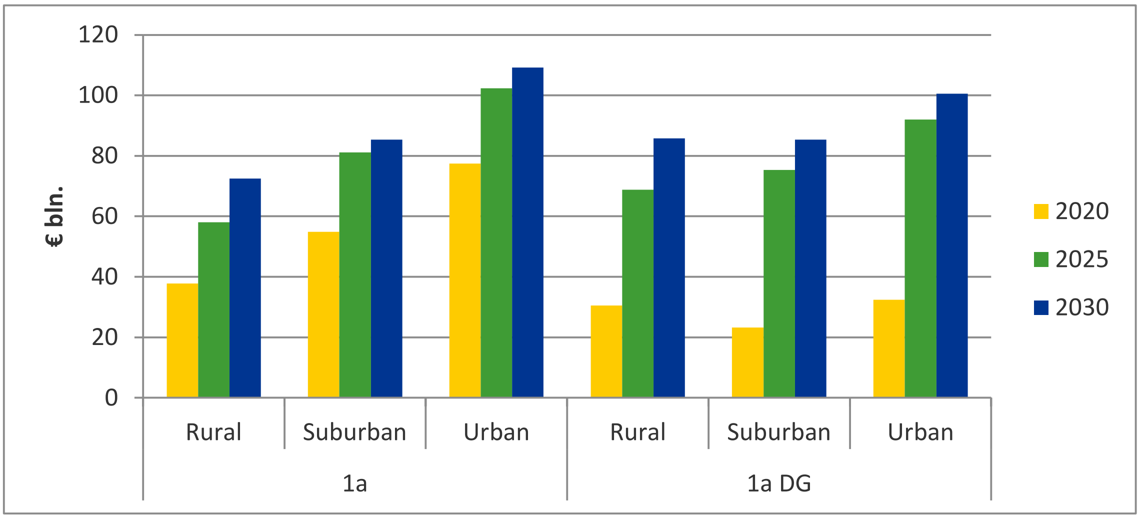


Figure 83 Cumulative reinforcement cost of each type of typical networks in Scenarios 1a and 1a-DG (EU-28, in EUR bn)

In our basic simulations, we have assumed that solar PV is more or less equally distributed over the entire length of a given feeder[45]. The first sensitivity listed above is intended to evaluate the effect of a more disadvantageous distribution of DG along the feeder from the network stability perspective, whereas the second case can be expected to lead to more favourable outcomes. In practice, we have assumed an approximately linear change in the density of solar PV from the start to the end of each feeder in these two sensitivities.

Similarly, the distribution of solar PV in LV networks in the original scenarios is correlated with demand with an approximately uniform share of DG-RES across different feeders. For the third sensitivity, this assumption was changed to a discrete distribution. More precisely, the number of feeders in each feeder category was split into three groups of equal size. For these three groups, we have then assumed a different concentration factors (150%; 100% and 50%) of the average penetration of solar PV in that feeder category. This sensitivity intends to assess the impact of a more variable spatial distribution of solar PV in real distribution networks.

Figure 84 compares the LV reinforcement costs for the sensitivity cases listed above with the results of Scenario 1-DG. As expected, the results show that an increasing concentration of solar PV capacity towards the end of individual feeders causes additional costs of LV reinforcement, whereas a location closer to the transformer results in decreasing costs. These differences are mainly related to voltage driven reinforcement costs, which increase with a higher concentration of solar PV at the end of a feeder due to reverse power flows in some cases. This additional voltage rise, which is caused by the increasing distance to the MV/LV transformer, leads to a 7% increase of reinforcement costs at the LV level, respectively 3% of total costs. In contrast, a decreasing density of solar PV along individual feeders reduces reinforcement costs at the LV level by around 5%.

In contrast, the variation of the DG-RES penetration across multiple feeders does not lead to any tangible change of reinforcement costs at the LV level. Although costs will be higher on individual feeders, it seems that this effect is basically offset by savings on other feeders with a lower penetration of DG-RES.

45 Depending on the location of existing customer connections

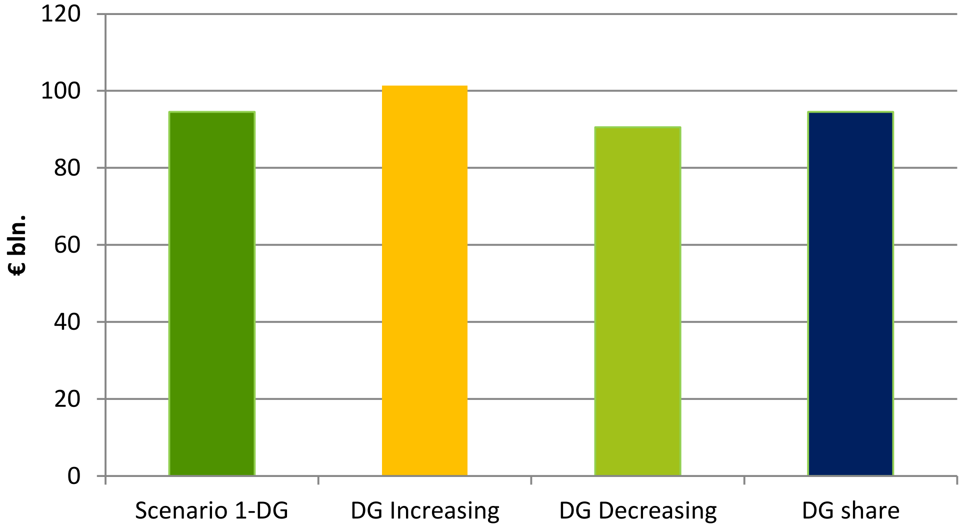


Figure 84   Cumulative cost of LV distribution reinforcements for different distributions of DG connection in 2030

Demand Response

In contrast to the transmission level, the need for distribution expansion is directly driven by load growth in general, or the development of peak demand in particular. Consequently, demand response can be expected to be very effective in reducing the need for distribution expansion. This assumption is confirmed by the left part of Figure 85, which shows that DR helps to reduce the cost of distribution expansion by roughly one third (35%).

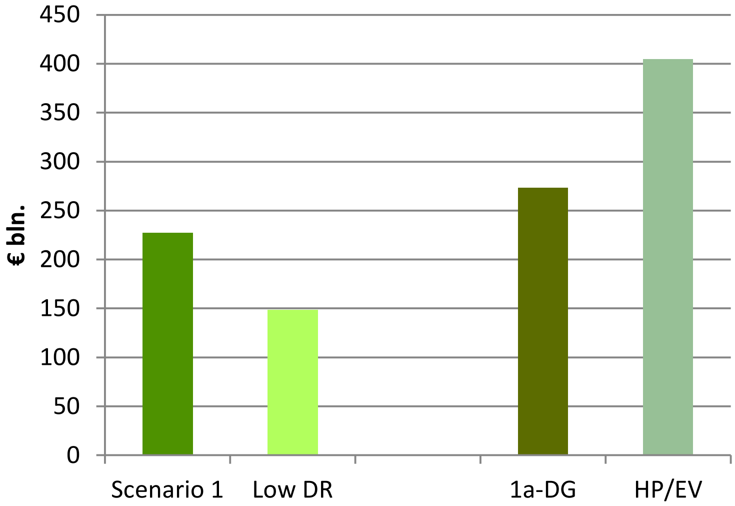


Figure 85   Impact of demand response and the additional load by HPs &EVs on cumulative reinforcement costs of distribution networks in 2030 (EU-28, in EUR bn)

Demand of Heat Pumps and Electric Vehicles

As explained in Section 3.4.3, we have also considered a sensitivity of Scenario 1a-DG with an increased penetration of heat pumps and electric vehicles. For the distribution analysis, we have furthermore assumed that both heat pumps and EVs are exclusively connected to LV networks and have updated the LV load profiles accordingly.

As Figure 85 shows this sensitivity leads to significantly higher costs of distribution reinforcements. Compared to scenario 1a-DG, this sensitivity causes additional costs of around € 130bn, which is an increase by almost 50%.

When interpreting this result, it is important to note that we have not assumed any external control and/or modification of the consumption by heat pumps and EV's in this sensitivity. Consequently, the additional costs reflect the impact of substantially increasing peak load. But in practice, an increased penetration of EVs and heat pumps is often expected to require controlled charging, and/or to support demand response. Indeed, as illustrated by the additional analysis on the value of demand response in Section 6.2.4 the inherent flexibility of heat pumps and electric vehicles principally neutralises the negative effects of the additional peak load caused by these applications.

4.5 Electricity Generation, Fuel Consumption and CO_2 Emissions

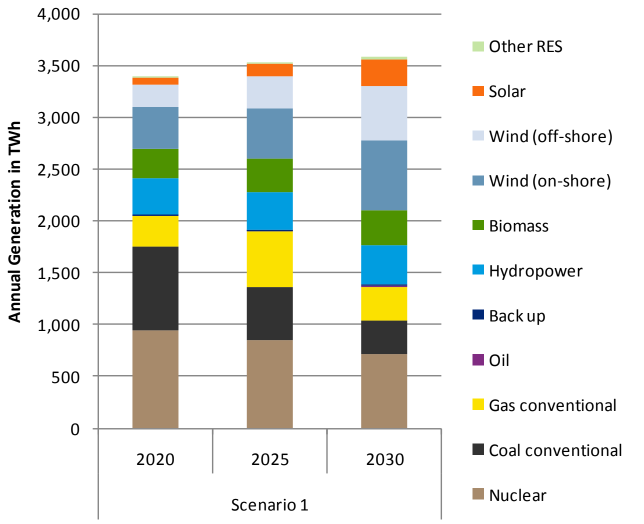
4.5.1 Electricity Generation

Based on the development of generation capacities and the underlying assumptions on electricity demand, commodity prices, etc. we have simulated the hourly dispatch of the European power system. With respect to electricity generation and RES-E curtailment we summarize the following key results for 2030:

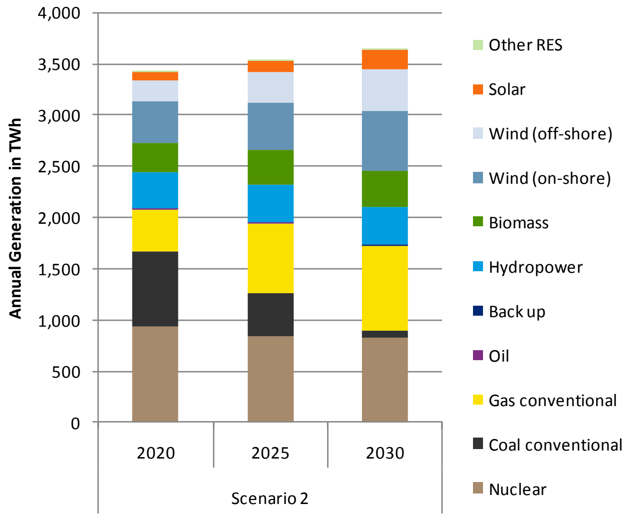
- The development of fuel and CO_2 prices has a major impact on the generation mix of conventional generation. In all scenarios we observe a switch from coal to gas production across the period 2020 to 2030, which is partly caused by the EU decarbonisation targets.
- The need for additional reserves and lack of flexibility may also decrease the ability of the system to absorb variable generation, which may require an increased curtailment of DG-RES, particularly when high outputs of renewable generation coincide with low demand.
- Overall levels of curtailment are modest in all main scenarios. However in scenarios with significant share of individual RES-E types, curtailment may increase to considerably values.

Figure 86 below presents the forecasted evolution of electricity generation in the EU-28 for the three main scenarios the period 2020 to 2030. In all scenarios we observe a fuel switch from coal to gas-fired electricity production between 2020 and 2030, which was already indicated in the results for the capacity expansion in Section 4.2. While in 2020 coal-fired generation is still expected to play a significant role in the overall generation mix, coal has a much lower contribution in 2030, particularly in Scenario 2 with relatively high CO_2 prices. Scenario 3 is the only scenario, in which coal is expected to continue to provide a significant contribution to overall electricity generation. In 2030 generation from gas-fired plants is highest in Scenario 2 with 826 GWh, which is almost twice the gas-fired generation in Scenario 3 (416 GWh) and approx. 60% higher than in Scenario 1 (332 GWh).

Scenario 1	2020	2025	2030
Nuclear	938	844	713
Coal conv.	810	514	322
Gas conv.	300	537	332
Oil	5	8	8
Back up	1	5	13
Hydro	358	367	375
Biomass	285	330	333
Wind (on)	397	477	674
Wind (off)	216	307	524
Solar	72	123	256
Other RES-E	13	16	31
Total	**3,397**	**3,529**	**3581**



Scenario 2	2020	2025	2030
Nuclear	938	842	828
Coal conv.	732	413	65
Gas conv.	408	690	826
Oil	5	2	5
Back up	1	1	7
Hydro	358	367	374
Biomass	292	339	357
Wind (on)	395	464	578
Wind (off)	216	303	412
Solar	70	107	180
Other RES-E	13	17	23
Total	**3,428**	**3,545**	**3,660**



Scenario 3	2020	2025	2030
Nuclear	931	838	804
Coal conv.	927	867	607
Gas conv.	235	359	416
Oil	2	3	4
Back up	1	2	5
Hydro	357	366	372
Biomass	282	316	326
Wind (on)	362	403	484
Wind (off)	177	230	323
Solar	67	89	129
Other RES-E	11	13	16
Total	**3,352**	**3,486**	**3,486**

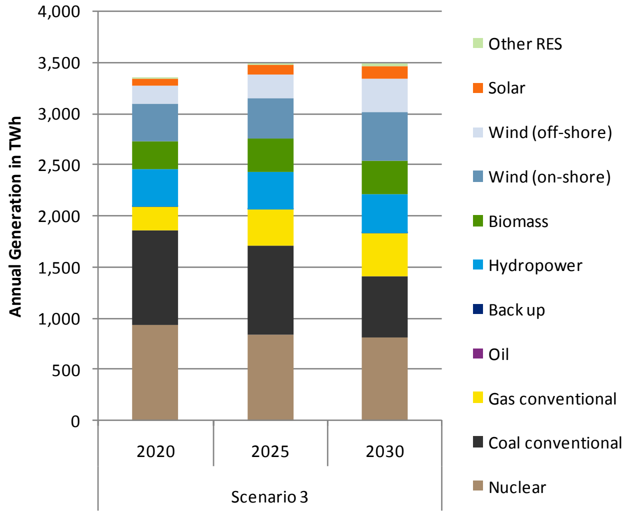
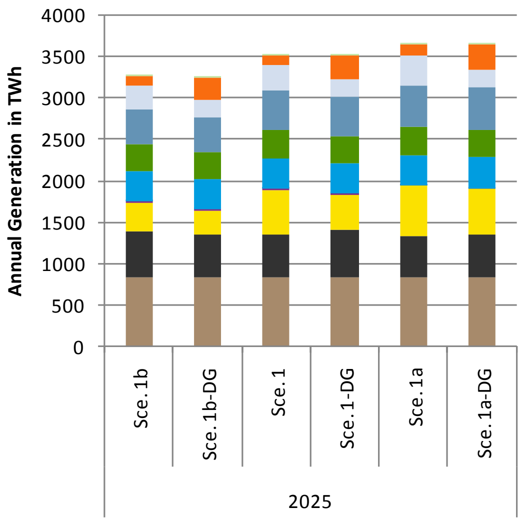


Figure 86 EU-28 electricity generation for the main scenarios (1, 2 and 3) for the period 2020 – 2030 (EU-28, in TWh)

For the sensitivities of Scenario 1 the importance of gas-fired generation decreases with decreasing load. While in Scenario 1a 377 GWh are produced in gas-fired power plants in 2030, the corresponding value for Scenario 1b is 209 GWh only, which represents a decrease by almost 45%.

2025	1b	1b-DG	1	1-DG	1a	1a-DG
Nuclear	844	844	844	843	844	843
Coal conv.	539	510	514	558	479	510
Gas conv.	356	290	537	433	615	547
Oil	5	4	8	7	7	7
Back up	2	2	5	3	3	3
Hydro	367	367	367	367	369	369
Biomass	323	323	330	330	330	330
Wind (on)	425	425	477	477	512	512
Wind (off)	286	216	307	216	346	216
Solar	118	263	123	280	146	308
Other RES-E	14	14	16	16	19	19
Total	**3,278**	**3,256**	**3,529**	**3,531**	**3,670**	**3,664**



2030	1b	1b-DG	1	1-DG	1a	1a-DG
Nuclear	713	713	713	713	713	713
Coal conv.	349	329	322	361	289	313
Gas conv.	209	196	332	279	377	335
Oil	6	9	8	10	7	9
Back up	9	9	13	15	14	16
Hydro	374	374	375	375	378	378
Biomass	334	334	333	333	355	355
Wind (on)	635	635	674	674	746	746
Wind (off)	480	286	524	307	595	346
Solar	224	417	256	473	318	567
Other RES-E	28	28	31	31	39	39
Total	**3,361**	**3,330**	**3,581**	**3,570**	**3,830**	**3,817**

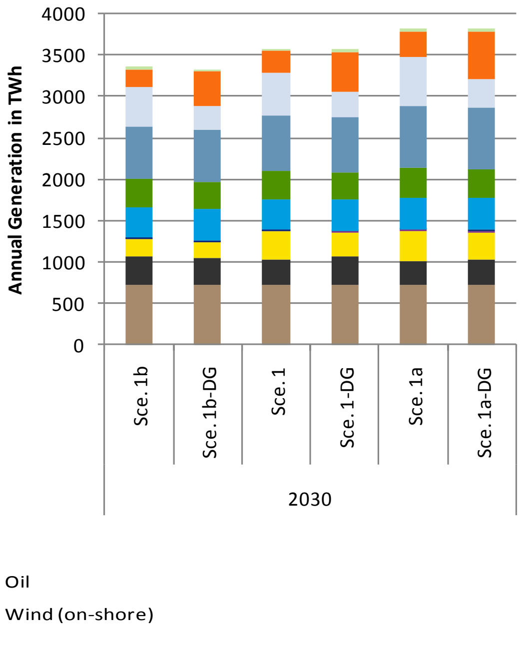


Figure 87 EU-28 electricity generation in the variations of scenario 1 (1, 1a, 1b) in the years 2025 and 2030 (EU-28, in TWh)

4.5.2 Curtailment of RES-E

Apart from generation by technology, we have also analysed the curtailment of RES-E, mainly wind and solar. Results are presented in Figure 88 and Figure 89 below, which illustrate the expected level of curtailment across the various modelling scenarios. The overall curtailment of wind and solar power remains relatively low. For instance in Scenario 1, which shows the highest level of curtailment, 23 TWh or about 1.6% of available electricity from wind and solar PV cannot be absorbed by the grid in 2030. Wind power accounts for more than 90% of total curtailment, representing about 1.8% of total wind generation. Conversely, the curtailment of solar PV remains below 2 TWh in all three main scenarios, or less than 1% of electricity available from solar PV.

Figure 88 also shows that curtailment in scenarios 2 and 3 is much lower than in scenario 1. Apart from an absolute reduction, curtailment also decreases in relative terms, i.e. it stays below 0.8% of wind generation) in both scenarios, which is approx. half of the level of curtailment in scenario 1. This indicates that the need for curtailment is positively correlated with the penetration of wind power.

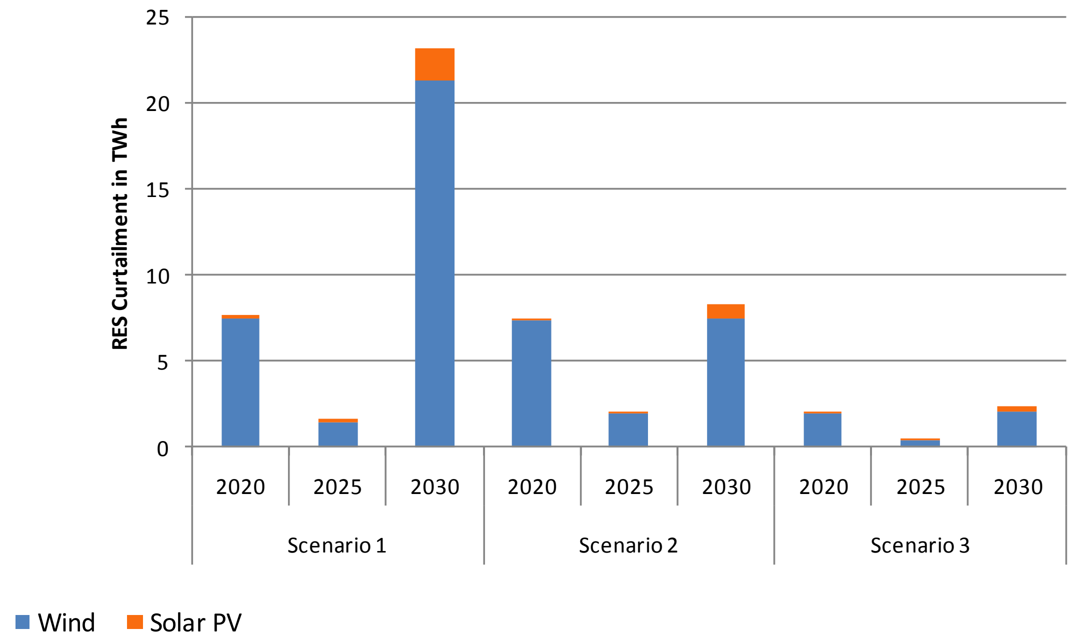


Figure 88 Curtailment of RES-E for the three main scenarios (1, 2, 3) in 2020 to 2030

Between 2025 and 2030, curtailment values increase considerably due to the increasing share of RES-E generation. The sensitivity cases of Scenario 1 show an increase in curtailment between DG and non-DG scenarios. As illustrated by Figure 89 below, curtailment of solar PV increases, while the values for wind decrease. This difference can be explained by a different composition of capacity from variable RES-E. Whilst the non-DG scenario are dominated by wind power, the DG scenarios have less wind power but a much higher penetration of solar PV.

The maximum level of curtailment is reached in Scenario 1a-DG, where curtailment of solar PV increases by 20 TWh compared to Scenario 1a, whereas curtailment of wind power decreases by about 9 TWh. Total curtailment in Scenario 1a-DG amounts to 43 TWh, or about 2.6% of total production from wind and solar power. When considering the difference in production only, these volumes correspond to a loss of more than 8% of incremental energy from solar power, but a gain of 1% of incremental energy from wind power. The marginal level of curtailment is thus considerably larger than the average values.

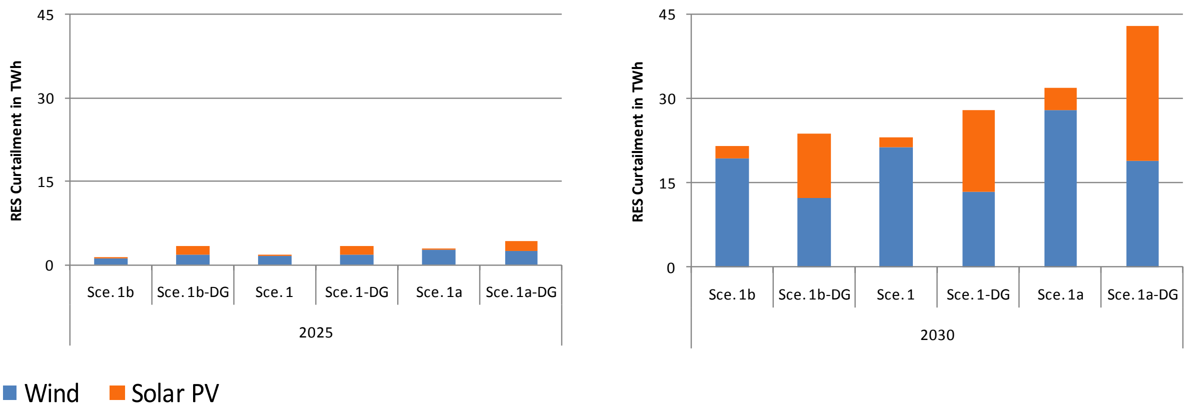


Figure 89 Curtailment of RES-E in the variations of scenario 1 in 2025 and 2030

In addition to the level of RES-E curtailment, the regional distribution of curtailment across EU 28 is of interest. As displayed by Figure 90 curtailment occurs mainly in regions that are characterised by significant amounts of variable RES-E and somewhat isolated from the rest of the European power system. Among others, this applies to the Iberian Peninsula Ireland and the United Kingdom, or Italy. In contrast, curtailment is much lower in France or Germany, which have a much higher level of connectivity with neighbouring countries, although both countries have a high share of wind and/or solar power.

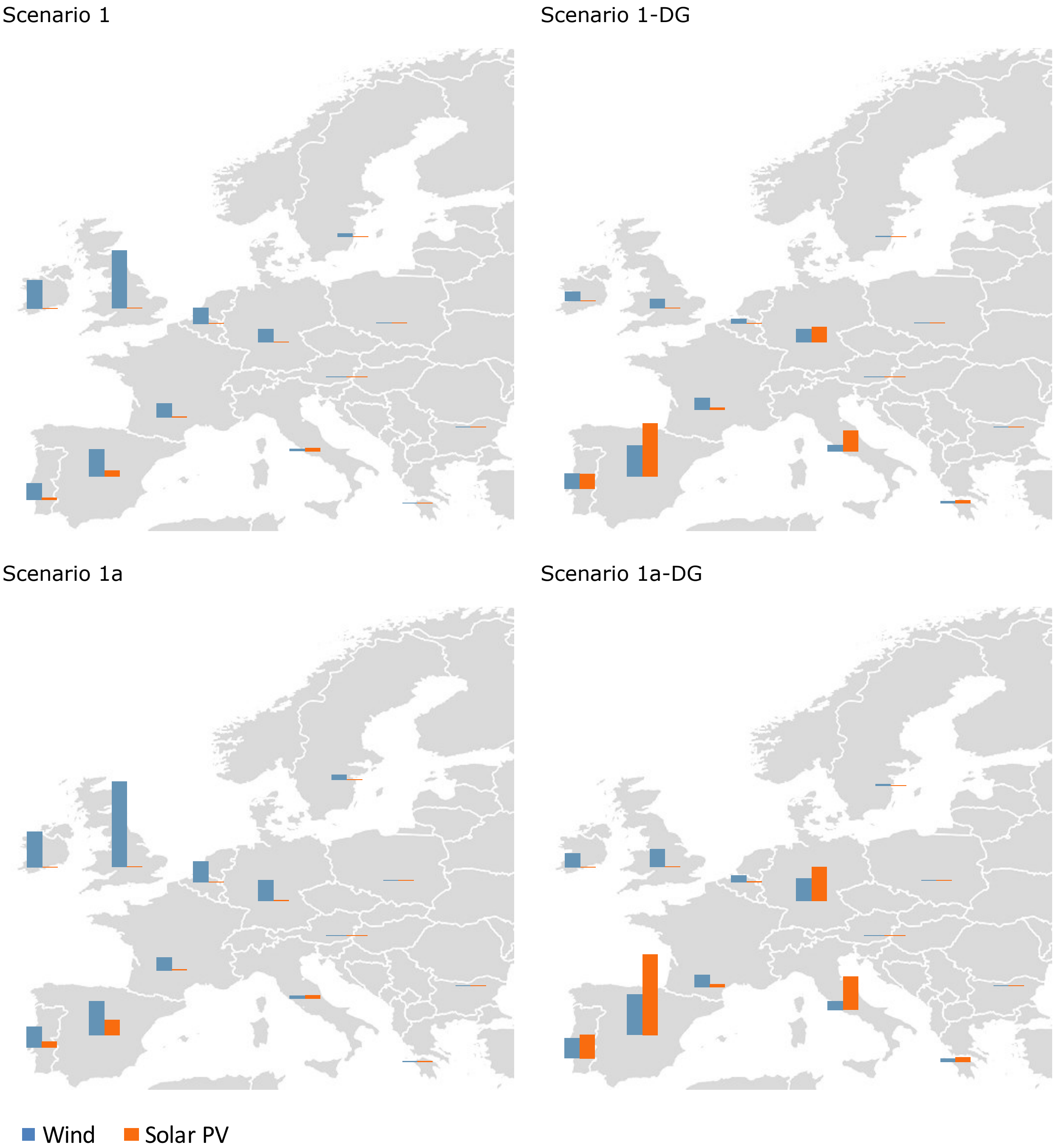


Figure 90 Regional distribution of RES-E curtailment for Scenarios 1 and 1a with and without additional DG (2030)

As shown in **Figure** 91, the development of the transmission infrastructure has a significant impact on RES-E curtailment. Curtailment of variable RES-E increases considerably in case of limited interconnector capacity, i.e. due to a reduced ability of the power system to balance fluctuating generation between different regions. As excess generation cannot be easily evacuated during times of high production, part of the output from RES-E generators has to be curtailed. In the extreme case of no additional investments in transmission infrastructure after 2020, curtailment is about four times higher than in scenario 1.

Conversely, demand response or a more distributed renewable generation make it easier for the power system to absorb additional energy from variable RES-E. This effect is particularly marked for the load-driven sensitivity where curtailment decreases to approx. 50% of its original value. Similarly, demand response helps to reduce curtailment, even if the reduction remains more limited both in absolute and relative terms.

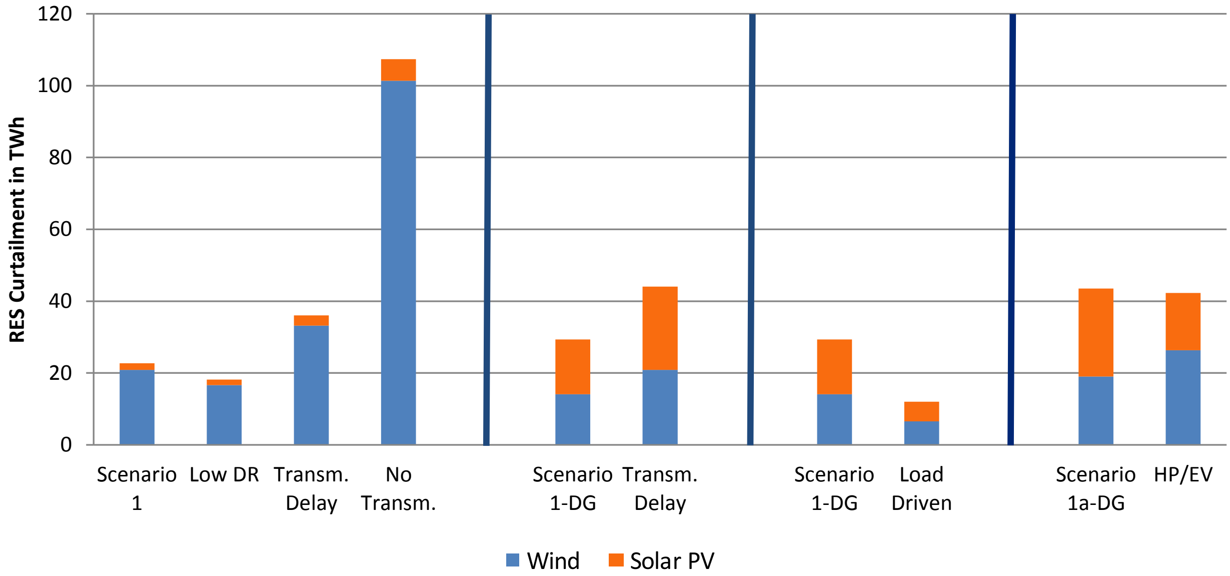


Figure 91 Curtailment of RES-E in the sensitivities of scenario 1 in 2030

4.5.3 Fuel Consumption

On the basis of the detailed dispatch modelling, we have analysed fuel consumption of conventional generation technologies, including uranium, coal, natural gas and oil. Figure 92 shows the results of our analysis for the main scenarios 1 to 3 for the EU-28. In 2020, fuel consumption is at a similar level in all scenarios, although it is slightly higher in Scenario 3 than in the other two scenarios.

Post 2020, we observe a substantial decrease in fuel consumption. The strongest decrease of about 34% can be observed in Scenario 1, which relies most heavily in RES-E. However, fuel consumption also decreases by about 16% in Scenario 3, which has the highest fuel consumption in all three scenarios. Furthermore, we observe a shift from using coal to natural gas in all three scenarios. This development is primarily driven by the decline of coal-fired capacity. In Scenario 2, this trend is further reinforced by increasing CO_2 prices, which make coal losing its competitiveness in comparison with natural gas.

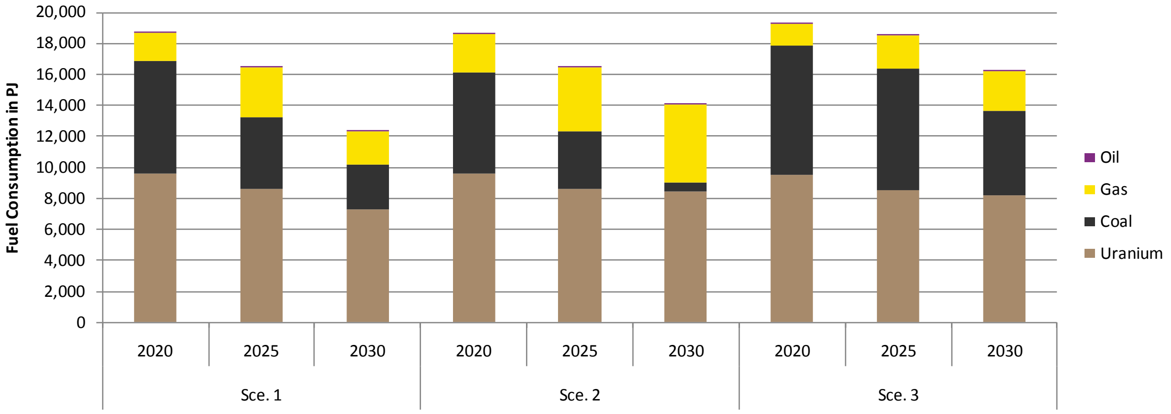


Figure 92 Fuel consumption by primary energy source of the main scenarios (1, 2 and 3) for the period 2020 – 2030 (EU-28, in PJ)

As discussed in Section 4.2 the structure of conventional power plants is very similar in the variations of Scenario 1, which are furthermore based on the same set of fuel and CO_2 prices. Consequently, it is not surprising to see that additional DG has a minor influence on fuel consumption only, although the resulting numbers still reflect different levels of consumption (see Figure 93).

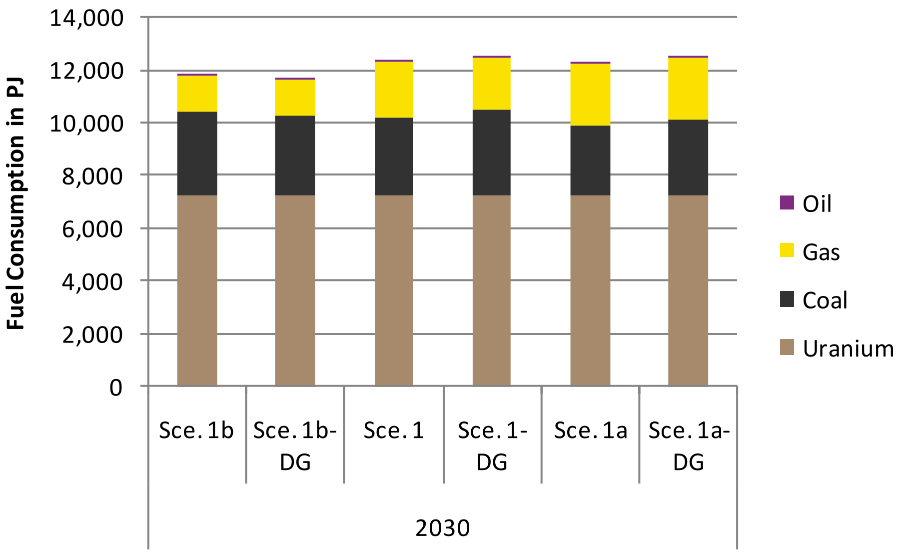


Figure 93 Fuel consumption by technology in 2030 in the variations of scenario 1 (1, 1a, 1b) in the year 2030 (EU-28, in PJ)

4.5.4 CO_2 Emissions

As illustrated in Figure 94, CO_2 emissions decrease in all main scenarios. In Scenarios 1 and 2, CO_2 emissions decrease by approximately 50% until 2030. Although Scenario 1 has a higher share of RES-E, higher CO_2 prices in Scenario 2 result in an additional shift from coal to natural gas, resulting in an additional reduction of carbon emissions by about 68 Mt due to the lower carbon content of gas compared to coal. In Scenario 3, carbon emissions decrease by around 25% from 2020 to 2030, with the reduction basically taking place after 2025. This development is a result of a lower increase of RES-E and a more limited fuel shift from coal to natural gas.

Overall, these results compare very well with the emission reduction trajectories achieved in the Energy Roadmap 2050. Although carbon emissions in our simulations are slightly higher than those reported by PRIMES in scenarios 1 and 3 in the initial years, this effect can be explained by a relatively large share of existing plants and low CO_2 prices, stimulating electricity production by coal plants. Conversely, very high CO_2 prices in Scenario 2 even lead to a further reduction of CO_2 emissions in 2030, due to a major shift from coal to natural gas.

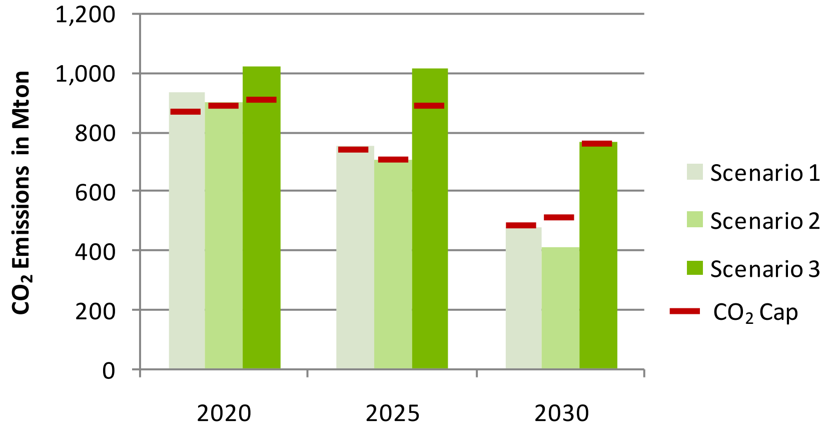


Figure 94 Annual CO_2 emissions for the three main scenarios (1, 2, 3) for the period 2020-2030 (EU-28, in Mton)

Note: CO_2 cap is based on estimated CO_2 emissions in the Energy Roadmap 2050

Figure 95 shows the results for the different sensitivities. Although demand response reduces emissions, the effect remains marginal, reflecting the limited reduction of RES-E curtailment (see Section 4.5.2 above). Conversely, reduced transmission expansion results in higher CO_2 emissions. This increase also remains marginal in case of a limited reduction of transmission expansion, but becomes substantial in the case without any transmission expansion post 2020. This effect reflects a higher utilisation of conventional thermal sources, in this case reflecting an increased curtailment of RES-E. The load-driven sensitivity results in slightly reduced emissions, which is in line with a decreasing curtailment of RES-E. Finally, emissions also decrease in the sensitivity 'HP/EV', but again by a limited amount only.

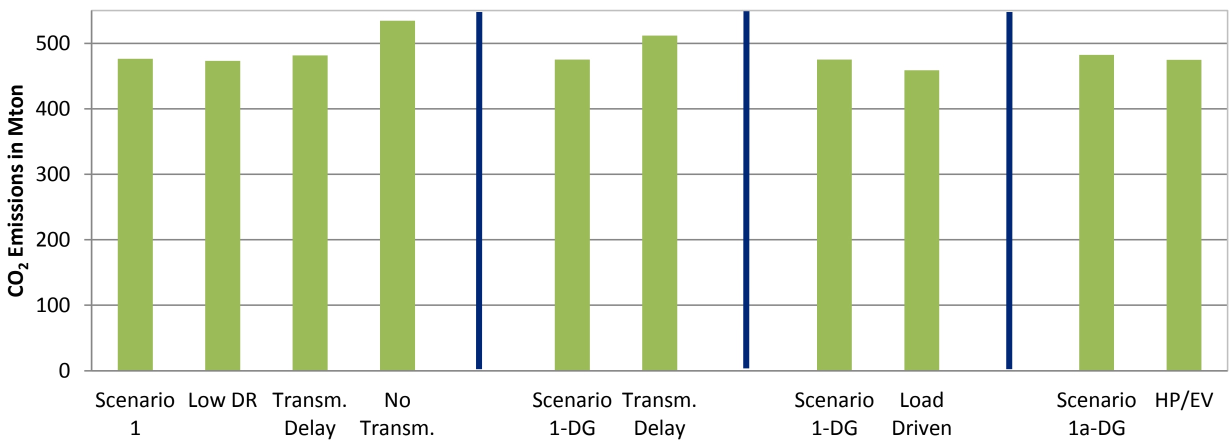


Figure 95 Annual CO_2 emissions for the sensitivities of scenario 1 in 2030

4.6 Costs of Electricity Supply

4.6.1 Costs of Investments into Additional Infrastructure Required to Integrate RES-E

Based on the infrastructure requirements presented in Sections 4.1 to 4.4, we have determined the necessary investments to be carried out until the year 2030. In this Section, we provide an overview of the cumulative capital costs which are required to facilitate the integration of RES-E. This analysis focuses on additional infrastructure that is required to integrate variable RES-E into the future generation park, including back up capacity as well as transmission and distribution reinforcements. Conversely, we do not consider any investments into generation in general, i.e. for RES-E and conventional power plants, which are considered in the context of incremental system costs in Section 4.6.2.

In the following, we provide an overview of total investments into additional infrastructure, including investments at the transmission and the distribution level. Thereafter, we specifically discuss the relation between additional transmission and back up capacity, due to the scope for partially replacing transmission capacity by additional back up capacity and vice versa.

Figure 96 summarises the annualized investment costs for additional back up, transmission and distribution infrastructure for the three main scenarios. This chart shows the following:

- The costs of additional infrastructure are increasing over time in all three scenarios and for all three types of infrastructure considered;
- Distribution reinforcements by far account for the largest share of overall costs, followed by investments into back up generation, whereas transmission expansion represents a minor share only;
- Overall costs are highest in Scenario 1, driven mainly by the costs of back up capacity and, to a lesser extent, transmission expansion.

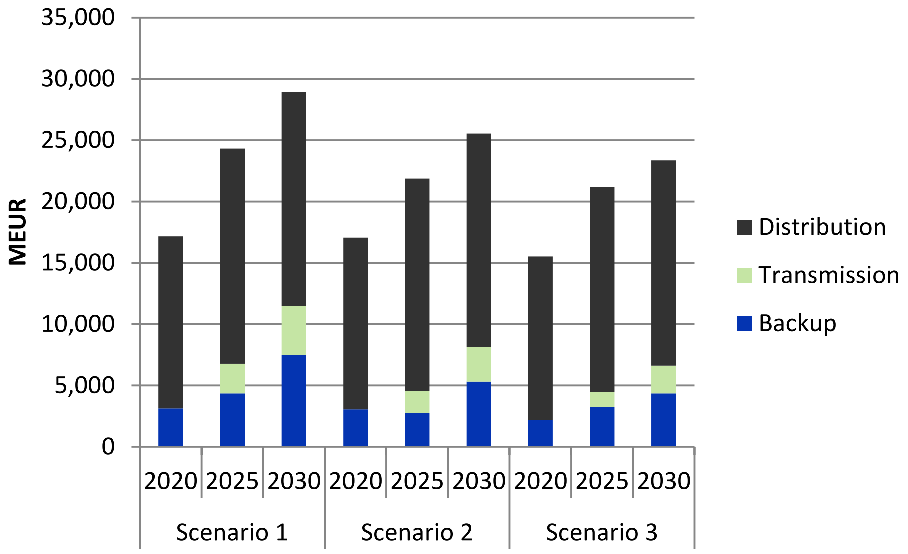


Figure 96 Annualized investment costs for the main scenarios

Figure 97 provides a similar comparison for the variations of Scenario 1. This chart principally shows very similar developments like Figure 96, such as the dominance of distribution investments and increasing costs over time. In addition, it is clearly visible that costs are lowest in Scenario 1b but highest in Scenario 1a-DG. Based on the analysis in the previous sections, it appears that this trend is partially caused by an increasing penetration of (decentralised) RES-E but also by higher consumption, i.e. we do not believe that it is possible to link the additional cost to one single driver.

In addition, Figure 97 also shows that the costs of the scenarios with a higher share of DG-RES are generally higher than those of the 'centralised' scenarios, at least in 2030. However, the resulting differences remain limited and do represent a fraction of total incremental costs only. Nevertheless, it is visible that the difference increases as the absolute penetration of DG-RES increases.

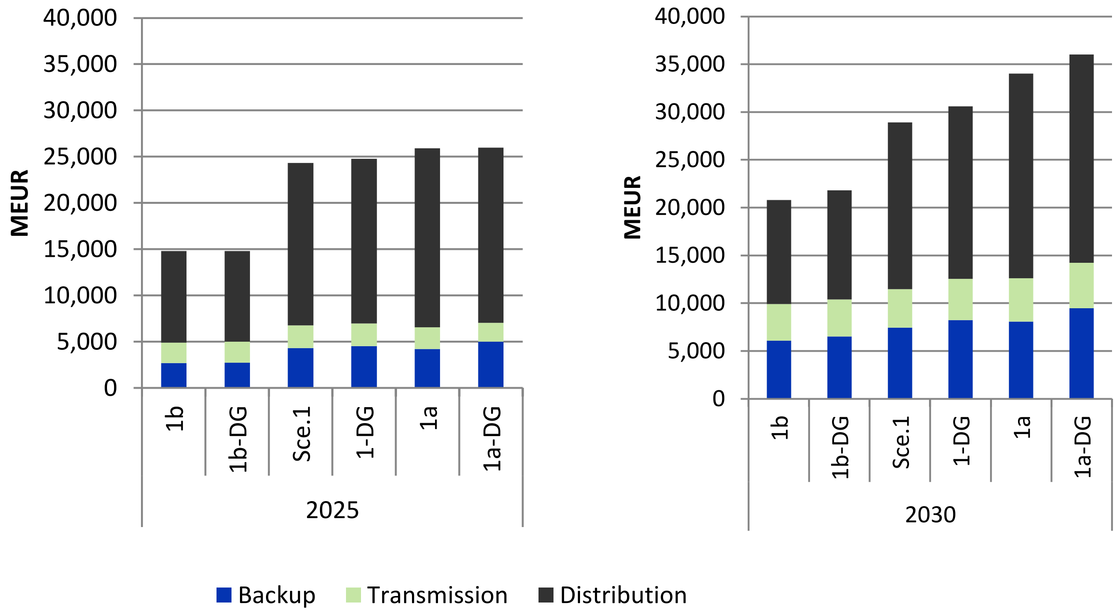


Figure 97 Summary of annualized investment costs for the variations of Scenario 1

It is also interesting to analyse the ratio between investments into new back up and transmission capacity. Whilst this ratio remains more or less constant in the three main scenarios (see Figure 96), there is a marked difference between the variations of scenario 1 with and without an increased penetration of DG (see Figure 97). More precisely, requirements for back up capacity are substantially higher in the DG scenarios, whereas one cannot observe a similar increase in transmission investments. This effect is most pronounced in isolated regions, like Great Britain or Iberia where a growing penetration of DG leads to an increase in back up capacity, whilst transmission expansion decreases. The interconnector between Great Britain and Norway represents an obvious example; here, total capacity in 2030 is significantly less in the scenario 1a-DG than in scenario 1a (compare Figure 71 on p. 67).

We assume that these effects can be explained by the substantially higher share of solar PV in the DG scenarios. Since solar PV has much lower capacity factors than other RES-E technologies, notably offshore wind, it is less economic to build additional transmission for the purpose of exporting excess electricity. In turn, this increases the need for building back up capacity since less transmission also reduces the scope for sharing reliability (i.e. back up capacity) between different regions. In this particular case, this negative effect is further aggravated by the fact that solar PV also provides a lower level of firm capacity, which also contributes to the need for additional back-up capacity.

Strictly speaking, the corresponding effects are thus the result of the RES-E technology mix but not of the choice for either centralised or decentralised generation. Indeed, it seems reasonable to assume that the outcome would have been the same if the variations of Scenario 1 in Figure 97 were based on large transmission-connected solar PV installations.

This assumption is supported by the results of the load-driven sensitivity (see Figure 98). This sensitivity has the same penetration of decentralised RES-E and solar PV as scenario 1-DG. Nevertheless, it leads to a simultaneous reduction of investments into transmission and back up capacity, even in comparison with scenario 1 with its more "centralised" mix of RES-E. A comparison of the three scenarios (1, 1-DG, load-driven) confirms that the choice between centralised and decentralised generation alone does not automatically lead to either an increase of decrease of infrastructure requirements. Instead, the need for transmission and back-up capacity is primarily driven by the mix of different RES-E technologies with different capacity factors and their regional distribution. As discussed above, an increasing share of DG-RES may thus very well lead to increasing infrastructure requirements and costs, even if it initially helps to avoid investments into network capacity.

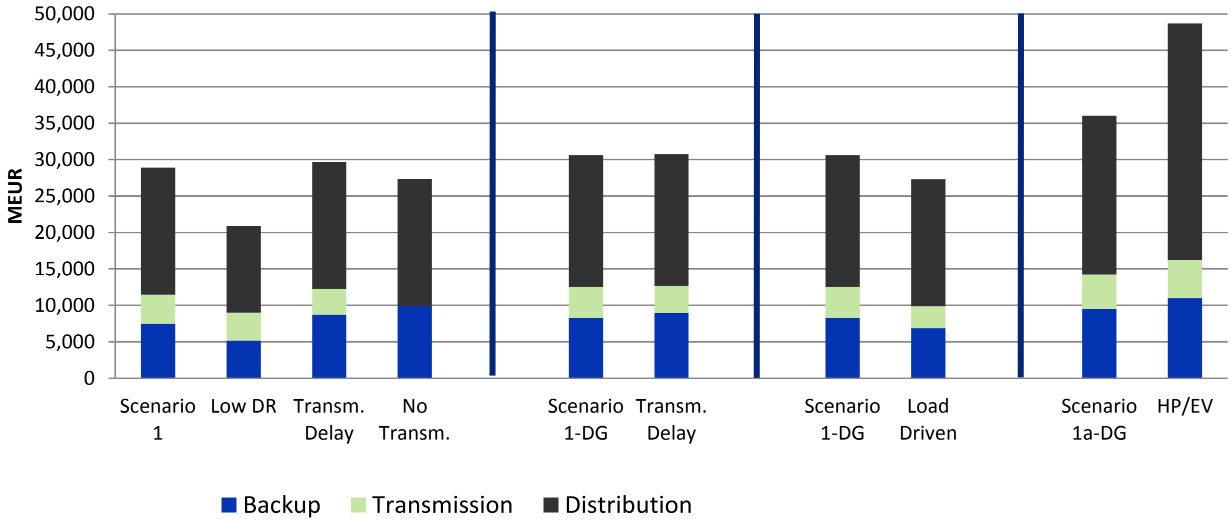


Figure 98 Summary of annualized investment costs for the sensitivities of Scenario 1

Apart from the load-riven scenario, Figure 98 also shows the impact of other sensitivities on investment needs into back up, transmission and distribution infrastructure. This comparison clearly highlights the potential benefits of demand response, which leads to the largest reduction of infrastructure rquirements across all sensitivities. It is also visible that DR leads to cost reductions in two areas simultaneously, i.e. distribution and back up capacity.

Perhaps surprisingly, reduced transmission expansion may increase as well as decrease total investments. Whilst investments decrease in the sensitivity without any transmission expansion after 2020, they are slightly higher in the sensitivity with delayed transmission for scenario 1 but remain more or less constant in scenario 1-DG. In this context, it is importanmt to bear in mind that these number do cover CAPEX only, but are exclusive of OPEX (see Section 4.6.2 below). Figure 98 also shows that reduced investments into transmission require additional investments into back up capacity in both cases, i.e. for scenarios 1 and 1-DG. In line with the previous discussion, these observations have to be seen in the context of the particular mix and regional distribution of RES-E technologies in these two scenarios.

The sensitivity 'HP/EV' finally requires significantly higher investments than the original scenario 1-DG. In is interesting to note that investment requirements increase in all three areas, i.e. for back up capacity, transmission and distribution. Nevertheless, the overall increase is mainly driven by higher costs for distribution, which account for the bulk of additional costs.

4.6.2 Incremental Costs of Electricity Supply

In Section 4.6.1, we have discussed the necessary investments into additional infrastructure that is required to integrate increasing volumes of RES-E into the European power system. Conversely, the current Section analyses the total incremental costs for electricity supply in the EU-28 in the different scenarios. This analysis covers both the fixed costs of additional infrastructure and the operational costs of both existing and new assets.

It is important to note that the fixed costs presented in this Section are therefore limited to investments into new generation capacities, including RES-E as well as conventional technologies, as well as additional transmission and distribution infrastructure. In contrast, the fixed costs of existing power plants and network infrastructure are neglected, as they are not known and represent a constant cost component for all possible future scenarios. In contrast, we do consider the operational costs of both existing and new power plants since both of them will require future expenses. Overall, these results thus represent the incremental costs of the power system in the future, whilst we do not consider the cost of investments that were carried out in the past or of replacing existing network infrastructure.

Figure 99 summarises total annualised costs of future investments for the three main scenarios. Not surprisingly, total costs increase over time as they include an increasing share of investments into new power plants that are partially replacing existing installations. Still, Figure 99 leads to the following observations:

- The overall costs of the three different scenarios follow a similar pattern and lead to comparable cost levels without significant differences.
- In all three scenarios, total incremental costs are clearly dominated by investments into RES-E and generation OPEX, which together account for some 75% of total costs. Conversely, investments into conventional generation and distribution are much smaller, whereas the costs of transmission expansion are almost negligible in perspective.
- Despite these similarities, the share of different cost components varies. In Scenario 1, investments into RES-E account for more than 50% of total incremental cost in the year 2030, whilst generation OPEX represent less than 25%. Conversely, generation OPEX account for some 45% of total incremental costs, whilst the share of RES-E is substantially lower but still significant (about 35%).
- We emphasise that these calculations are based on the costs assumptions for different types RES-E technologies as presented in section 2.1.2. When instead using the original assumptions of the Energy Roadmap 2050, incremental system costs would increase by some € 13 bn on an annual basis. This difference mainly reflects the fact that the Energy Roadmap 2050 did not anticipate the strong decrease of costs of solar PV in recent years, although this effect was partially compensated by much more optimistic assumptions on the future costs of offshore wind in the Energy Roadmap.
- Similarly, the technology assumptions of the recent 2030 Impact Assessment (2013 Reference scenario) lead to an increase of annual costs by some € 35 bn in 2030 in comparison with the assumptions used for this study. In this case, the difference is mainly caused by considerable less optimistic assumptions on the future costs of offshore wind power in the Reference Scenario, as well as some 17% and 26% higher cost estimates for onshore wind and solar PV, respectively.

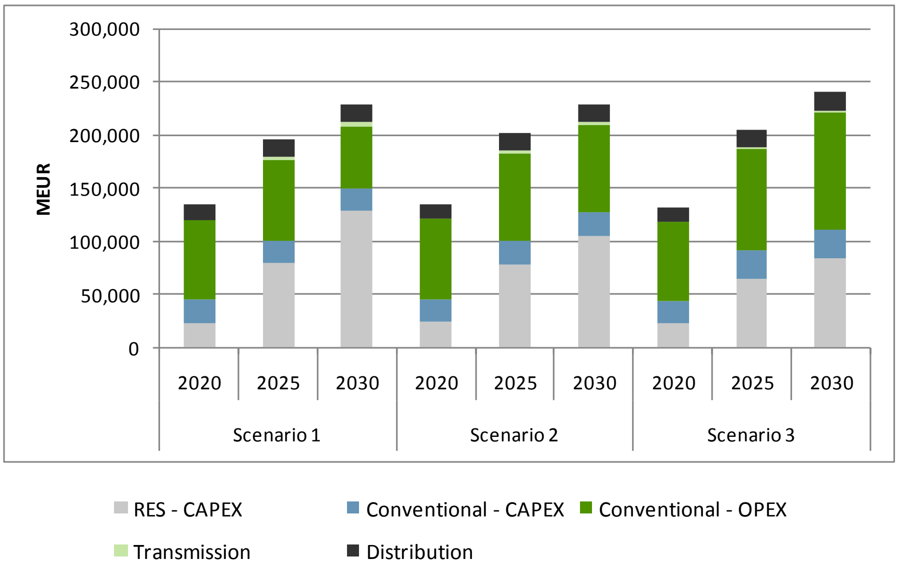


Figure 99 Incremental costs (annualised) for the main scenarios

Figure 100 presents the corresponding results for the variations of Scenario 1. Not surprisingly, overall costs are lower in Scenario 1b but higher in Scenario 1a, due to the different levels of consumption. More interestingly, the results in Figure 100 do not generally show any tangible impact of the scenarios with an increased penetration of DG-RES. Only for Scenario 1a-DG it is possible to identify a slight increase in cost in the year 2030 compared to Scenario 1a.

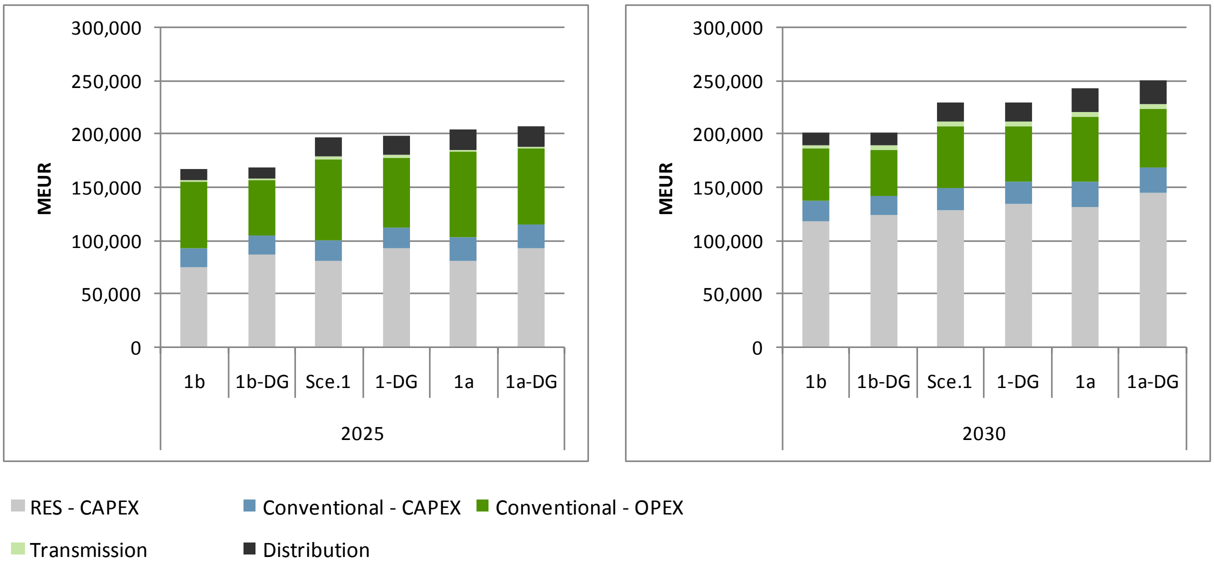


Figure 100 Incremental costs (annualised) for the variations of Scenario 1

For the sensitivities of Scenario 1 and its variations the incremental costs are presented in Figure 101. This picture again confirms the benefits of DR. In addition to savings in infrastructure (see Section Figure 98 above), DR also allows for a reduction of generation OPEX. Similarly, a slight decrease can be observed for RES-E CAPEX and transmission investments in the load-driven sensitivity. As reduced transmission expansion leads to higher conventional generation and hence higher OPEX, the total system costs of the load-driven sensitivity end up increasing the costs of Scenario 1-DG by a small amount.

Comparing the restricted transmission sensitivities, overall minor differences in the total incremental costs, apart from the 'No Transmission sensitivity', can be stated. The significantly higher total cost in the 'No Transmission' sensitivity are mainly related to high CAPEX and OPEX of conventional power plants, which need to back up and replace RES-E during periods with limited production from RES-E. This also shows that potential savings in transmission investments are more than offset by additional investments into back up capacity and higher OPEX.

A high penetration of heat pumps and EV's without controlled charging and/or operation leads to increasing costs. These are mainly caused by additional distribution reinforcement costs, which obviously reflect the additional peaks of the HP/EV profile. However, the growth of distribution costs can be mitigated by demand response as further discussed in Section 6.2.4.

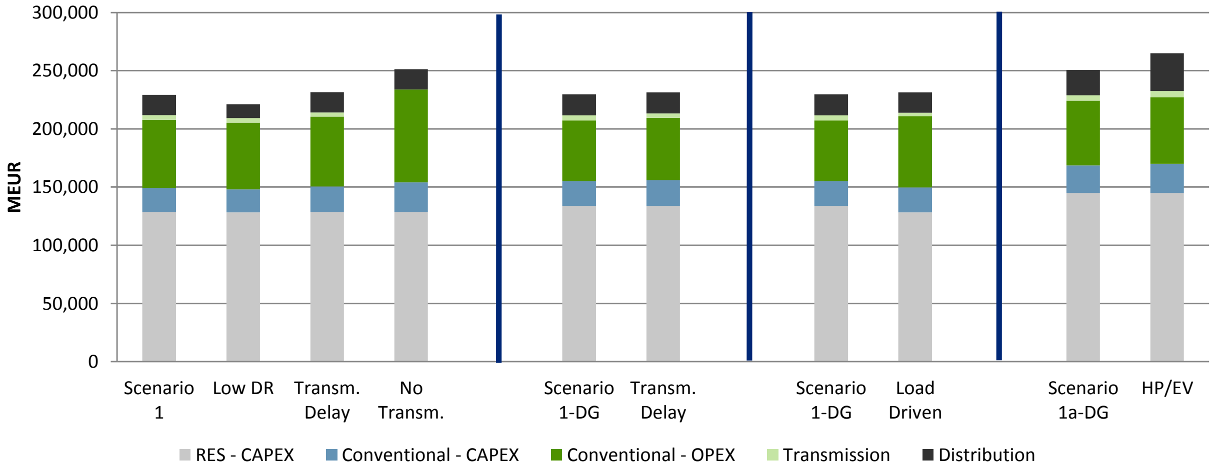


Figure 101 Incremental costs (annualised) for the sensitivities, 2030 (EU-28, in EUR bn)

4.7 Main Drivers of Infrastructure Requirements

This chapter has analysed the impact of different scenarios on the need for generation, transmission and distribution infrastructure and the capability of the power system to absorb electricity produced from RES-E. Apart from comparing the different developments, we have also tried to explain the observations made and identify the underlying reasons. Based on this background, this Section aims at describing the main factors that are driving future infrastructure requirements and the associated of integrating increasing volumes of variable RES-E into the power system. In addition, we also discuss potential technical barriers, which may limit the ability of the European power systems to accommodate further volumes of variable RES-E.

The analysis in this chapter shows that the costs of system integration are especially driven by the following factors:

- Technical characteristics of different RES-E technologies, including aspects such as the firmness of capacity, average capacity factors and daily capacity factors;
- Regional distribution of different types of variable RES-E;
- Size and connection level of individual RES-E installations;
- Relative share of variable RES-E;

- The structure and flexibility of the existing generation and network infrastructure;
- Network design standards.

Please note that the first three aspects are directly related to RES-E installations themselves, whereas the latter two represent exogenous conditions that are independent from RES-E. The relative share of variable RES-E finally depends on the relative size and development of variable RES-E, on the one side, and demand, on the other side.

With regards to technical characteristics, the results presented in this chapter clearly show that variable RES-E are unable to guarantee production (i.e. firm capacity) at all times. Even in case of a major expansion of European transmission networks, variable RES-E thus have to be backed up by conventional generation capacity, in order to ensure reliable power supply to consumers at all times. This effect is particularly pronounced for technologies that have a very low probability of being able to deliver at times of high load and/or where production is highly correlated with neighbouring regions, such as in case of solar PV in the Northern parts of Europe.

Conversely, average annual capacity factors of different RES-E technologies mainly influence the economics of transmission or, alternatively, conventional generation technologies. Whilst high capacity factors from for instance offshore wind make it economically attractive to export excess energy to other regions or to reduce the capacity of conventional plants that are capable of providing base load at reasonable costs, this is not the case for solar PV.

Similarly, the benefits of and/or need for additional transmission infrastructure are strongly influenced by the regional distribution of different types of RES-E. Among others, this is clearly illustrated by the scenarios that are predominantly based on offshore wind in North-western Europe, the decentralised scenarios with a larger penetration of solar PV in the Southern parts of Europe, and the 'load-driven' scenario with a higher contribution from RES-E located in Central and Eastern Europe. These three (groups of) scenarios lead to considerable changes in the structure of the optimal transmission infrastructure at a European level. In addition, they also change the relative share of different types of infrastructure, as well as generation OPEX, even if total costs remain very similar in our simulations.

The costs of distribution expansion are strongly driven by the connection level of RES-E, which effectively reflects the size of individual installations. Consequently, a higher level of DG-RES principally increases the need for distribution network reinforcements and thus leads to increasing costs. However, this is only true once a certain penetration of DG has been achieved, whereas more limited shares of DG may also help to defer investments. Similarly, the actual impact strongly depends on coincidence with demand and the firmness of capacity as illustrated by the cost savings due to small-scale CHPs. This highlights once more that overall infrastructure requirements depend on a multitude of factors and cannot necessarily be linked to one single driver.

Among others, this is certainly true for the relative share of variable RES-E. As a general rule, limited volumes of RES-E, whether fluctuating or not, will mainly help to reduce generation OPEX (or network losses), although may occasionally also help to avoid investments. Once a certain penetration has been reached, however, the trend reverses and additional RES-E capacity leads to increasingly higher costs. The actual impact depends strongly on the local situation, especially at the distribution level, as well as on the regional context, in particular with regards to necessary transmission reinforcements.

Similarly, the costs of integrating variable RES-E are obviously influenced by the structure and flexibility of the existing generation and network infrastructure. Consequently, we observe very limited additional infrastructure in those areas that have access to a large amount of flexibility or that are well interconnected with other countries, such as Norway or Switzerland. In contrast, the challenges of RES-E integration are highest in more peripheral regions with less flexible generation and demand, such as Ireland or the UK.

Although the distribution analysis in this project has necessarily been based on simplified assumptions, it has nevertheless shown the importance of different network design standards. Indeed, countries that have traditionally provided for substantial reserve margins in their distribution networks, such as Germany, can initially integrate a substantially larger share of DG-RES than other countries with different design standards like the UK.

These considerations illustrate how different types of infrastructure investments are influenced by different developments and needs. In particular, we note the following:

- **Transmission** investments are mainly driven by differences in the costs of available electricity (energy) at different locations. From the perspective of RES-E integration, this mainly relates to the potential for transporting cheap electricity from regions with surplus energy to other locations. As mentioned above, transmission is thus relatively more attractive for RES-E technologies with higher capacity factors, such as wind power, whereas its value is more limited for instance for solar PV. In addition, transmission also helps to share flexibility and firm capacity between different regions. However, our results indicate that this is more a 'by product' of available transmission capacity rather than a substantial driver for network reinforcements.
- The addition of **back up capacity** primarily depends on the need to ensure reliability at times of insufficient supply from variable RES-E. Back up capacity is more likely to be required in isolated regions that are relatively distant from other locations and/or in areas with a larger share of variable RES-E with low capacity factors, such as solar PV. It is thus of a more local nature. Nevertheless, as the example of France shows, the benefits of firm capacity can also be exchanged between different locations where sufficient transmission capacity is available.
- **Distribution** reinforcements finally are driven by two different, though related reasons. As the penetration of DG grows, reverse flows (i.e. from lower voltage levels to higher voltages) will eventually exceed the thermal limits of the existing network. In many cases, especially in LV networks, DG will first lead to voltage problems. Whilst a violation of thermal limits can mainly be resolved by physical reinforcements, voltage problems may also be mitigated and/or resolved through various other means (compare Chapter 6.5).

4.8 Role and Impact of DG on Infrastructure and Costs

Much of the analysis presented above confirms the findings of previous studies, including previous work done by the authors of this study or other studies carried out on behalf of the European Commission. But to date, these studies have generally been limited to the analysis of generation and transmission. In contrast, this study has specifically looked at the distribution level and the impact of DG on a European level. This section, therefore, summarises some key findings related to the role and of DG on infrastructure requirements and the costs of electricity supply.

As further explained the analysis carried out under this study leads to the following conclusions with regards to role and impact of DG:

- DG does not have any direct impact on need for transmission and back up capacity;
- DG may both cause and avoid distribution expansion, depending on:
  - Type of DG (i.e. controllable resources vs. variable RES-E and correlation with load);

- Penetration of DG;
- Vertical distribution (i.e. connection level);
- Horizontal distribution (proximity to load and transformer stations);

- Need for distribution expansion can be strongly reduced when combined with more flexible demand or decentralised storage.

Our simulations do not generally show any clear advantage for either centralised or decentralised generation in terms of the need and cost of transmission and back up capacity. A comparison of scenarios 1, 1-DG and the load-driven scenario shows that the costs of transmission may both increase or decrease. Conversely, the need for back up capacity generally increases in the DG scenarios. However, a closer analysis reveals that these impacts are mainly driven by the type and regional distribution of variable RES-E on a European level rather than the choice between centralised and decentralised generation within a given region. This finding also appears obvious if one considers that the aggregate balance of the power system in a given region will always be the same, irrespective of whether individual customers or production are connected to the local transmission or distribution networks.

In contrast, the analysis in this chapter clearly shows that DG may have a significant impact on the need, composition and costs of distribution expansion. Moreover, the analysis shows that DG may both cause and avoid distribution expansion.

Similar to the case of transmission and back up capacity, the need for distribution expansion is strongly influenced by the type of DG, i.e. the choice between controllable resources, such as thermal plants fired by fossil fuels and/or biomass or hydropower, and different types of variable RES-E, like solar PV or small-scale wind turbines. The corresponding effects furthermore depend on the penetration of each type, or DG in general, at a given voltage level. As illustrated by the schematic diagram in Figure 102 these different effects can be explained as follows:

- Controllable resources can be used to reduce peak load and may therefore avoid or at least defer distribution expansion, provided that they can be reliably called upon at times of high load.
- Conversely, the possible savings from variable DG remain highly limited as they cannot guarantee a firm supply of electricity at times of peak load. This is especially true for solar energy as the output from solar PV is minimal during times of winter peak load at higher latitudes as well as during high load hours in the evening in Southern Europe. Moreover, the variability at individual locations or within smaller areas at the distribution level is much higher than for larger regions with a well-developed transmission network.
- In both cases, the initial savings will eventually turn into a need for additional distribution capacity as the penetration of DG increases[46]. As a general principle, this negative effect can be expected to be more critical in case of variable RES than for controllable DG. This is mainly due to the limited capacity factor of variable RES-E (in particular solar PV), which require a much higher capacity to be installed to deliver the same volume of energy. Secondly, it is again easier to constrain the production of controllable resources at times of low load, thereby reducing possible reverse flows to higher voltage levels, without losing the corresponding volume of available energy.
- In the case of variable RES-E, the need for distribution expansion furthermore depends on the correlation between the production profile of a given resource and the local load profile. In this context, it is often argued that solar PV is less critical than wind power. However, it is important to

46 Or, alternatively, the production available from DG will have to remain unused, i.e. be curtailed.

bear in mind that the need for network expansion is mainly driven by the maximum amount of capacity to be transported but not the correlation between average production and consumption.

These considerations clearly indicate that there is no universal relation between the share of DG and the need of distribution expansion, but that it will strongly depend on the local situation. Consequently and as also reflected by the results of our numerical analysis, similar developments may thus lead to different outcomes under different circumstances. In this context, it is furthermore important to bear in mind that the results presented above are strongly influenced by considerable load growth assumed in the PRIMES scenarios, a generally limited penetration of solar PV until 2030, and the simultaneous addition of decentralised CHP and gas motors.

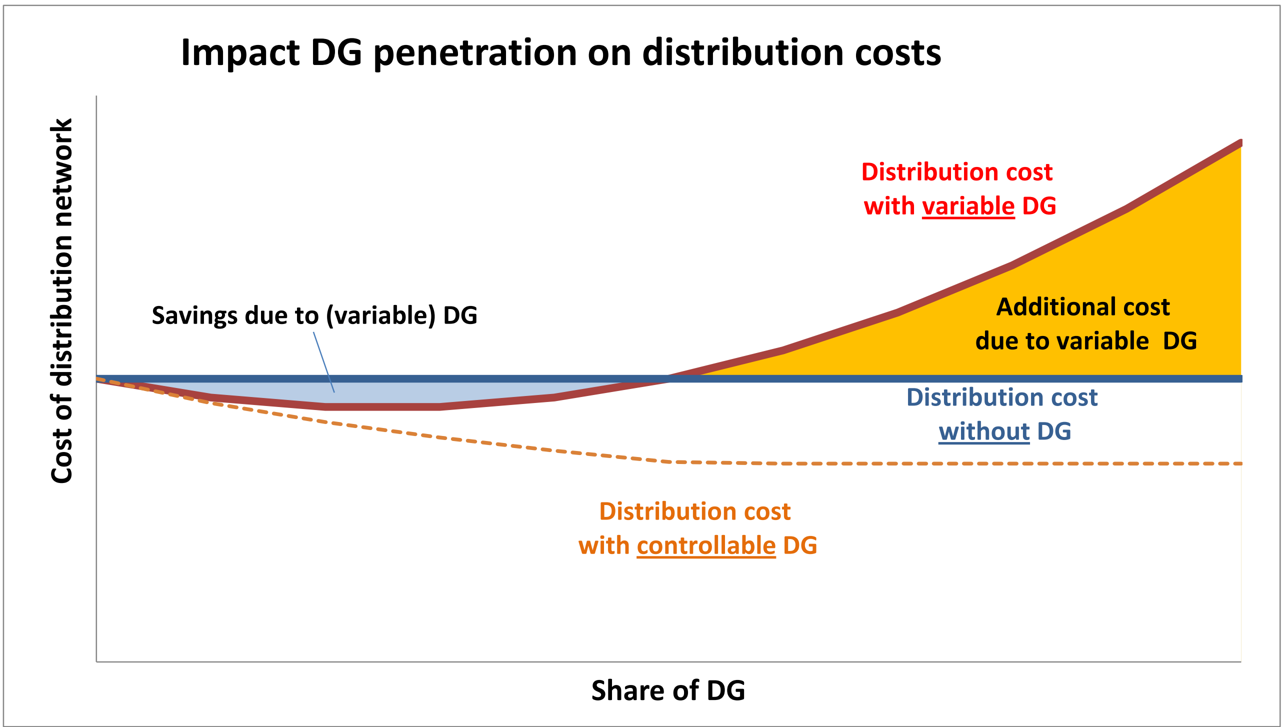


Figure 102 Impact of load and DG on cost of distribution (schematic diagram)

Besides the type and overall penetration of DG, the need for distribution expansion also depends on the vertical and horizontal distribution of DG. This effect is straightforward in case of vertical distribution, i.e. the connection level as it will generally be able to accommodate a higher absolute penetration of DG at higher voltage level. Conversely, connecting DG to higher voltage levels may also reduce the benefits of avoided or deferred network expansion, especially in case of controllable DG.

In addition, the analysis in Section 4.4 (see p. 77) has shown that the need for distribution expansion is also influenced by the horizontal distribution of DG, i.e. its proximity to load and transformer stations:

- Similar to the regional distribution of generation capacities, including variable RES-E, network investments can generally by minimised by installing production capacities close to demand. As also shown by experience to date, this implies that DG will generally be more beneficial in areas with high load, i.e. urban and suburban areas, whereas it is more likely to require additional investments in rural areas with lower load density and weaker networks.

- The distribution of DG along individual feeders also has an impact. As shown by Figure 84 on p. 79 locating (variable) DG further closer to the end of individual feeders increases costs, whilst costs can be reduced by limiting the distance closer to the transformer at the start of each feeder.

Overall, the impact of DG thus depends on a multitude of different factor. In principle, this also provides the basis for managing the need for distribution expansion, for instance by influencing the type and local distribution of (variable) DG through adequate regulatory options (see Chapter 7). Due to the potentially very large number of small DG installations in future networks, however, corresponding arrangements might trun out to be fairly complex and could involve significant transaction costs.

As an alternative, it is thus worth bearing in mind that the impact of DG also depends on the flexibility of local demand. Consequently, the potential disadvantages may at least be partially overcome by increasing local flexibility, for instance by means of more flexible demand or decentralised storage. Whilst we explore the possible benefits of storage in Section 6.2.3 below, the analysis in Section 4.4 has already illustrated that DR may help to substantially reduce the need for distribution expansion (see Figure 85 on p. 79). These results indicate that the benefits of DG will be particularly large when combined with other developments leading to more flexible local demand at the distribution level.

5 ASSESSMENT OF MARKET IMPACTS

5.1 Introduction

This chapter analyses the impact of different scenarios on the power system, the electricity market and selected generation technologies. More specifically, this chapter cover the following areas:

- Section 5.2 analyses the development of market prices in the wholesale electricity market and the ancillary services market;
- Section 5.3 assesses the impact on selected generation technologies and pump storage, both in terms of annual operating hours and gross margins; and
- Section 5.4 concludes this chapter by identifying and discussing potential barriers for investments into electricity generation and storage.

5.2 Market Prices

5.2.1 Wholesale Market Prices

The market model has been applied to project the development of wholesale electricity prices for the period 2020 - 2030 for each of the modelling scenarios. Figure 103 below summarises the development of European electricity wholesale prices in all three main scenarios (Scenario 1 - 3). Next to the demand-weighted average wholesale price for the EU-28, we provide information on the range of average annual wholesale prices of individual countries.

In general, electricity prices reflect the development of underlying commodity and CO_2 prices, subject to the evolution of the generation and transmission infrastructure. In addition, we would like to highlight the following observations:

- Whilst average wholesale prices are similar across the three main scenarios in 2020, they diverge afterwards. Moreover, whereas prices increase significantly in Scenario 2 and especially Scenario 3, they stabilise in Scenario 1 after the year 2025.
- Regional variations are substantial in the year 2020, but decrease significantly in the scenarios with optimised transmission expansion in 2025 and 2030. However, scenarios with very limited transmission expansion continue to show large price differences between regions.

In 2020, average electricity prices are similar across all three main scenarios. Scenario 1 and 2 have only minor differences in the underlying generation mix and are based on the same commodity price assumptions. Despite higher coal prices, Scenario 3 shows slightly lower electricity prices, which are caused by significantly lower carbon prices. Towards the end of the modelling horizon, the three main scenarios reveal greater differences in terms of supply structure and underlying commodity prices. As an effect of the high share of RES-E generation with low variable costs, Scenario 1 has the lowest electricity wholesale prices. In contrast, Scenario 3 has the highest electricity prices due to the continued reliance on thermal generation technologies in combination with increasing commodity prices.

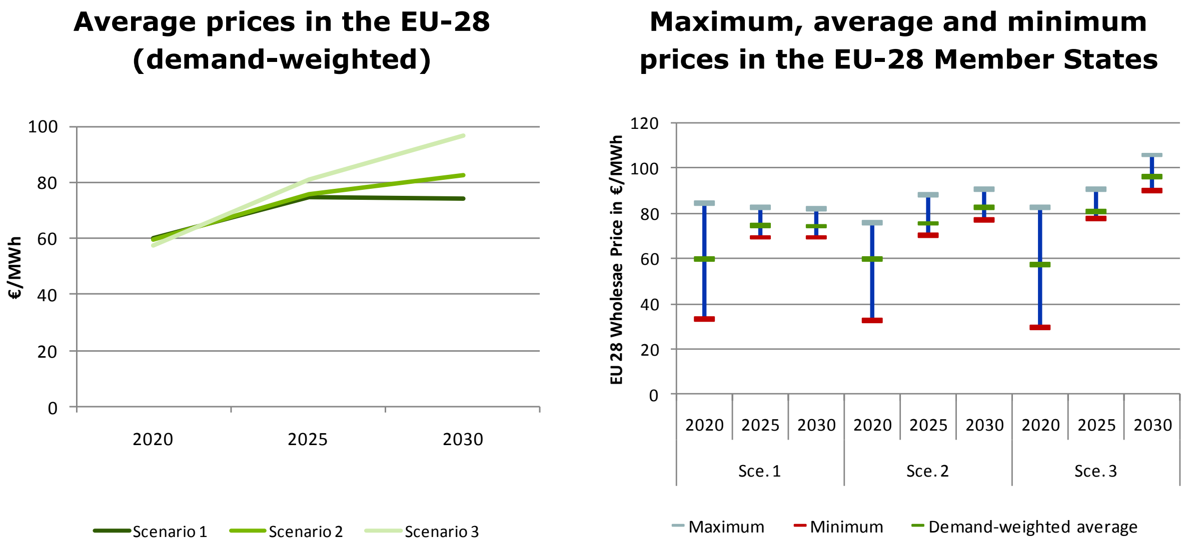


Figure 103 Development of annual wholesale electricity prices in the EU-28

Figure 104 shows the evolution of the ratio between peak and offpeak prices in the EU-28 from 2020 to 2030. This ratio remains fairly stable in Scenarios 1 and 2, but is slightly higher in Scenario 1 than in Scenario 2. In contrast, the peak / offpeak spread strongly declines in Scenario 3, i.e. whilst it is the highest in 2020 it is the lowest in 2030. This development can be explained by a decreasing spark spread in this scenario.

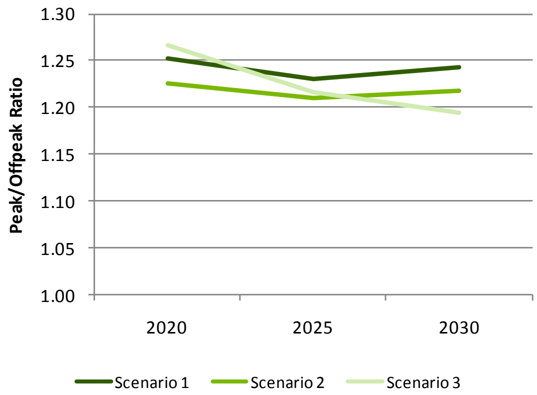


Figure 104 Development of peak / offpeak price ratio for the three main scenarios

When analysing the range of annual average prices across the individual Member States, we observe a trend towards market integration as a result of increasing interconnector capacity between individual countries. The effect is illustrated in Figure 105, which shows annual average electricity prices in the period 2020 – 2030 for six selected countries, i.e. Germany, Spain, Sweden, Greece, Italy and the UK. Due to a limited degree of interconnection, price differences remain significant in 2020. In 2030, most of the prices converge to a European price level, although Spain and Portugal show slightly lower prices, whereas prices in Italy and Greece still remain above those in Central and Northern Europe.

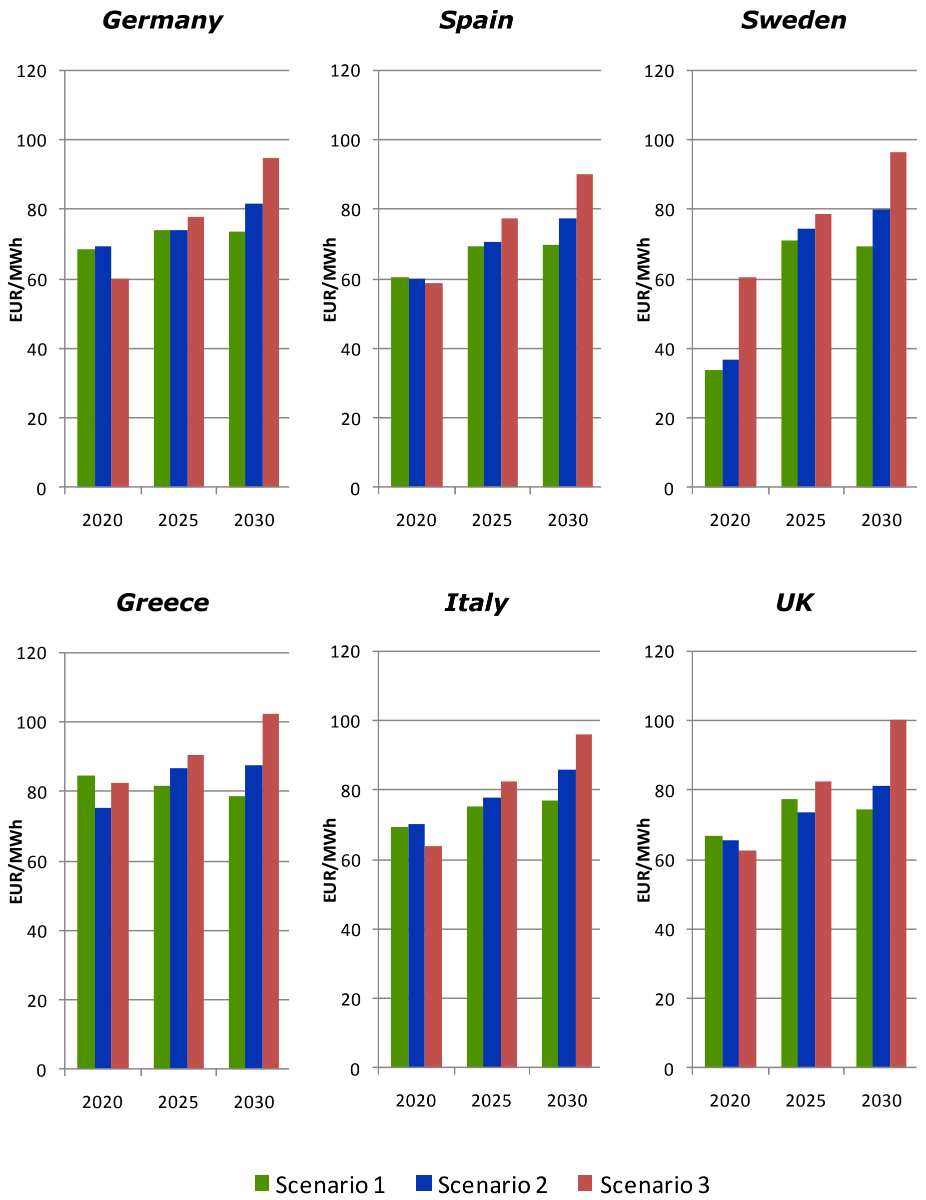
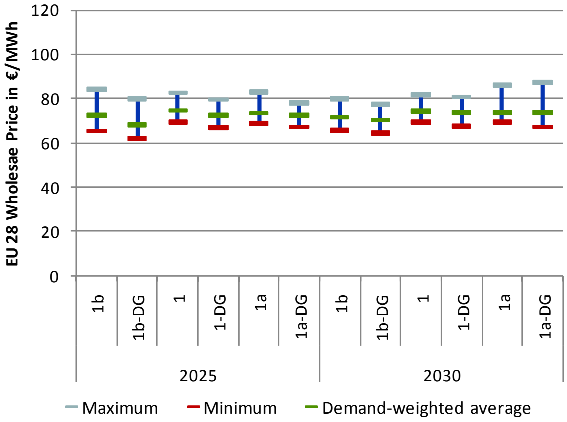


Figure 105 Selected national wholesale prices (demand-weighted average) for scenarios 1, 2 and 3 for years 2020, 2025 and 2030.

Figure 106 depicts the development of average annual wholesale prices and peak / offpeak ratios in the EU-28 for the variations of Scenario 1. This chart shows that average European prices do not show any significant variations across the variations of Scenario 1. However, decentralized generation in the DG sensitivities seems to exercise a limited downward pressure on wholesale market prices. The effect of DG is even more pronounced in case of peak / offpeak spreads, which are substantially lower in the DG scenarios, reflecting the much larger contribution from solar PV feeding it during the daily peak period.



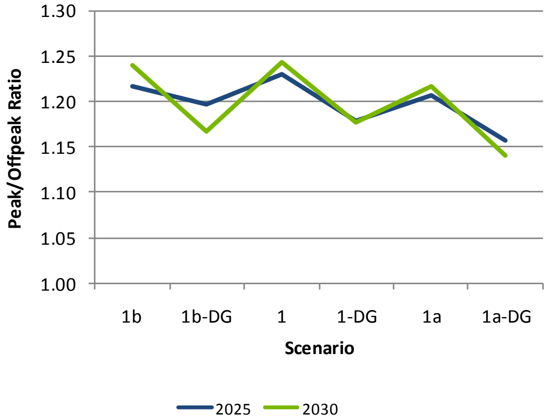
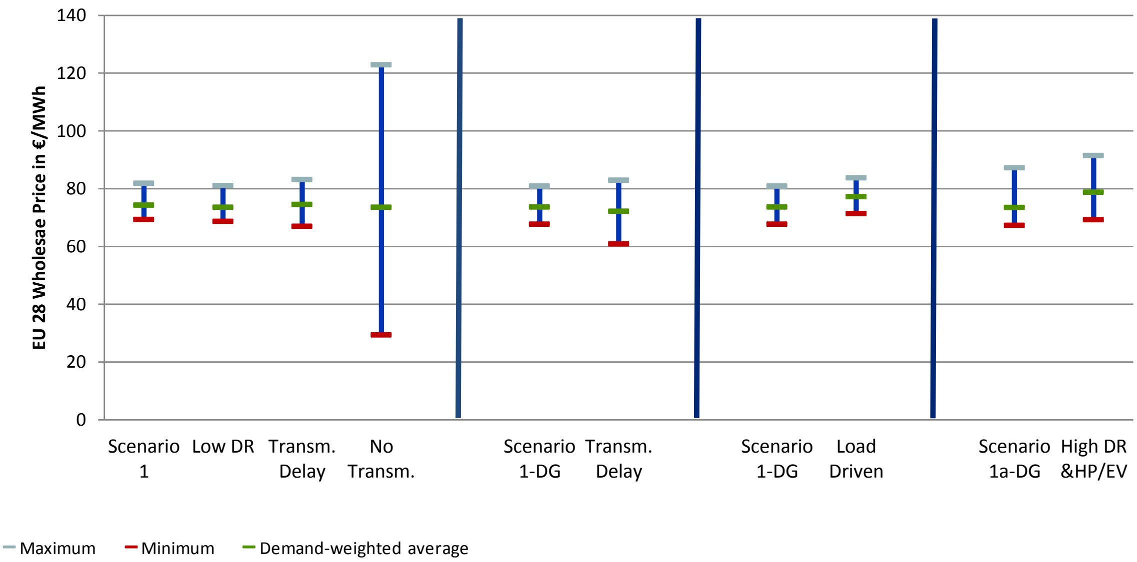


Figure 106 Average wholesale prices and peak / offpeak ratios in the EU-28 in the variations of Scenario 1

Figure 107 shows wholesale prices and price spreads for the sensitivities of scenario 1. While average prices are comparable for most scenarios on a European level, considerable differences in national electricity prices can be observed for the sensitivity without transmission expansion after 2020. Simultaneously, the peak / offpeak ratio substantially increases in this sensitivity, most likely caused by an increasing frequency of periods with either excess power or a need to rely on back up capacity in regions with a large share of variable RES-E. In contrast, the sensitivity with delayed transmission in scenario 1-DG results in a further decline of the peak / offpeak ratio. This effect, which appears surprising on first sight, reflects an increasing impact of solar PV on power prices during the day in regions with a high penetration of solar PV.

In addition, it is interesting to note the different development of average spreads in the two sensitivities with demand response and a high penetration of HPs/EVs. Demand response leads to declining spreads, indicating a reduction of situations with either very high or low prices. Conversely, the addition of HPs/EPS, without demand response, results in increasing volatility and an increasing spread.



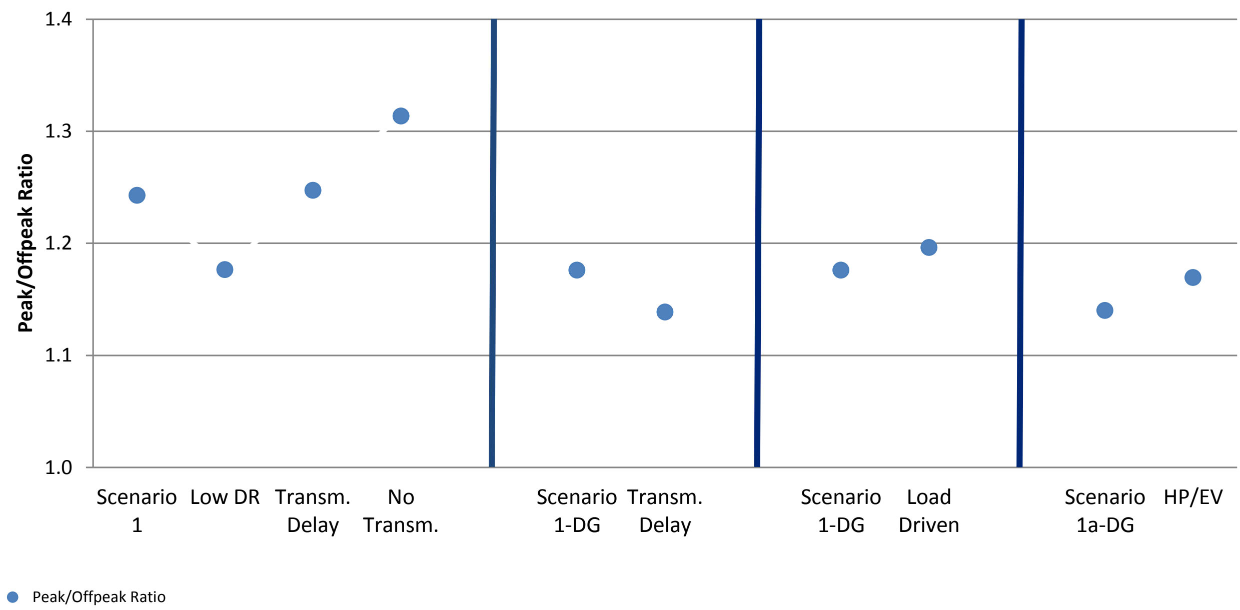


Figure 107 Average wholesale prices (upper) and peak / offpeak ratios (lower) in the sensitivities of Scenario 1 (EU-28, in EUR/MWh and in %)

Figure 108 shows the evolution of the annual price duration curve in three selected markets (Germany, Spain, and Great Britain) in the three target years 2020, 2025 and 2030, based on Scenario 1. All three countries show two similar trends, i.e. a general increase of market prices over a large part of the year as well as a general "flattening" of the price duration curve. The former observation can be explained by the general increase of fuel and CO_2 prices as already mentioned above. Conversely, the latter trend reflects an increasing homogeneity of the conventional plant structure as the existing generation fleet is increasingly replaced by two types of power plants (CCGTs and coal fired steam turbines), with no major changes in plant efficiency assumed over time.

The "flattening" of the price duration curves shows that an optimal level of transmission seems to allow large parts of the European power system functioning as a "copper plate" for many hours during the year, despite a rapid growth of variable RES-E. One can clearly observe that the number of hours with either extremely low prices (excess production from RES-E) or very high prices (reliance on back up capacity) remains very limited in all three countries. At the same time, Figure 108 arguably illustrates that extreme situations seem to occur more often in the two peripheral markets but are less common in Germany, which is more centrally located and well connected with many other markets.

This observation highlights that transmission expansion represents a very effective instrument for dealing with the challenges of variable production by RES-E, and that it may in particular help to stabilise hourly wholesale price and reduce volatility.

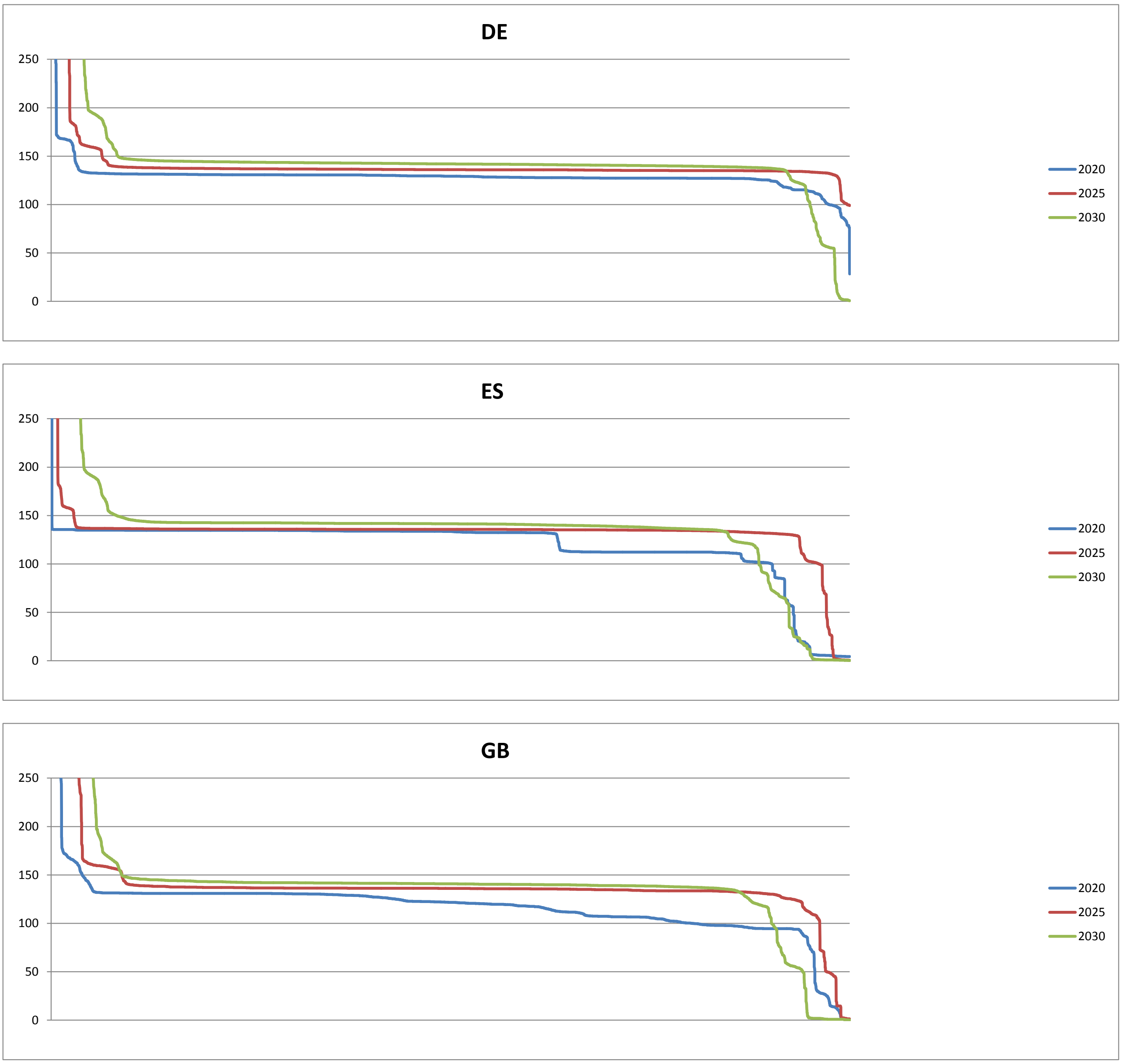


Figure 108 Price duration curves in selected markets from 2020 to 2030 (scenario 1)

Clearly, an unconstrained expansion of European transmission grids represents a rather strong assumption, which, based on experiences to date, appears to be rather unlikely to hold in practice. Figure 109 therefore compares the price duration curves of the same countries in the year 2030 for three different levels of interconnection, i.e. unconstrained (Scenario 1), reduced ("Less Transmission"), and without any transmission expansion post 2020 ("No Transmission"). This comparison leads to two interesting observations:

- First, Figure 109 clearly shows a rapidly growing share of either very high or low prices especially in Spain and Great Britain in the sensitivity without transmission expansion. This observation highlights the importance of transmission expansion in terms of avoiding not only an excessive volatility of wholesale market prices, but also a quickly growing curtailment of variable RES-E[47].
- Secondly, it appears that these effects do only occur at substantially reduced levels of interconnection. Conversely, a limited reduction of transmission expansion has a much more limited impact on market prices, and hence the ability of the system to utilise production available from variable RES-E. This indicates that the relation between transmission expansion and the curtailment of variable RES-E is not linear, and that an effective and efficient integration of variable RES-E may already be possible with transmission expansion that remains substantially below "optimal" levels.

Overall, Figure 109 thus provides two different messages. First, it partially supports the view sometimes quoted in the public debate that successful integration of variable RES-E may not necessarily require a full expansion of European transmission grids, at least not to the levels reported as optimal by this (and other) studies, or at least that the negative consequences of a reduced network expansion may be limited. But at the same time, it also supports the view that sufficient interconnection capacity is an essential precondition for reaching a very high penetration of variable RES-E.

47 Please note that price levels clsoe to zero indicate hours in which at least some variable RES-E have tob e curtailed.

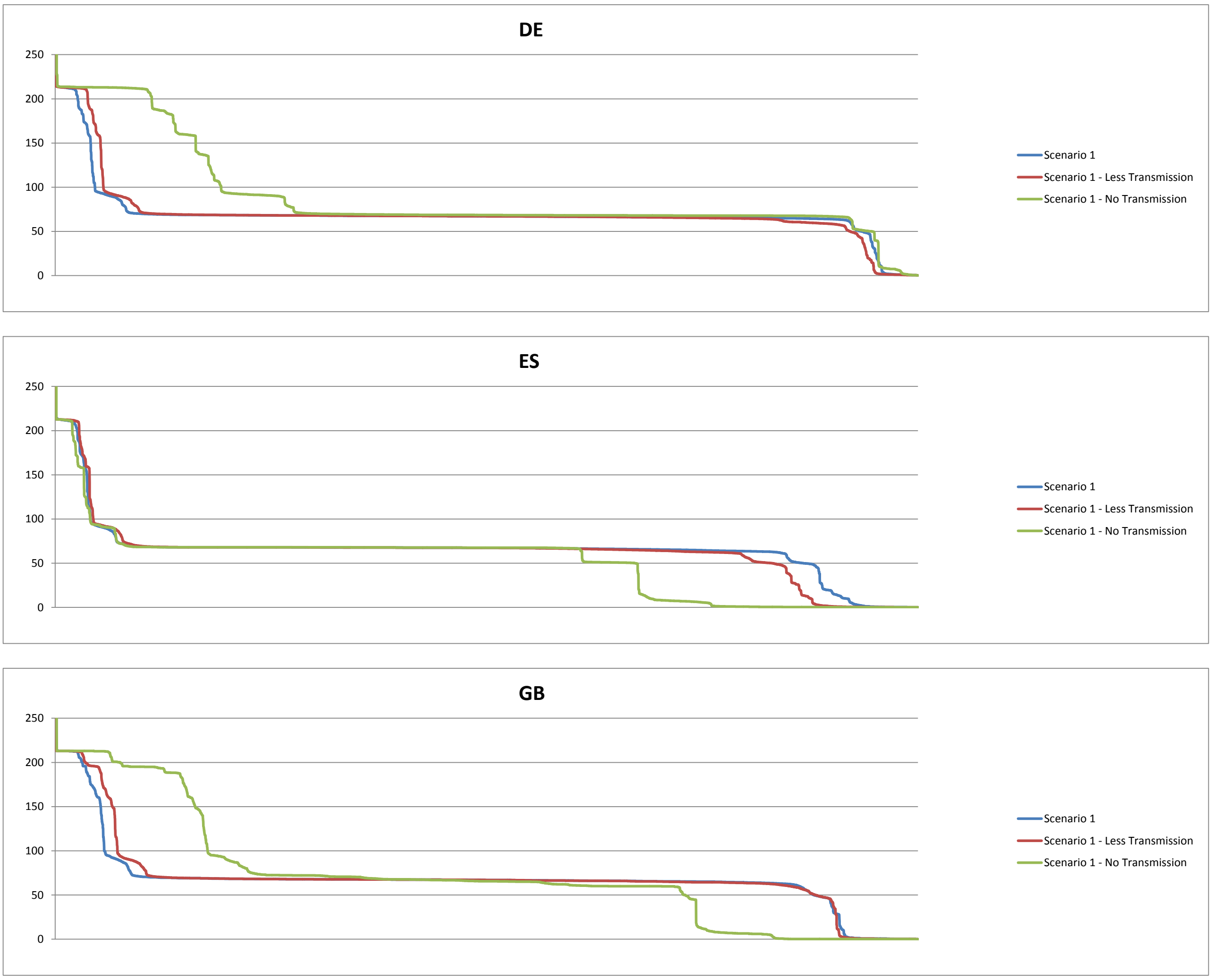


Figure 109 Price duration curves in selected markets for different levels of interconnection (2030)

5.2.2 Ancillary Services

The allocation of reserves to individual generating units has been determined in the wholesale market model by means of co-optimization of energy and reserves. We have used this result to calculate the marginal prices for different types of ancillary services in each hour, based on the ancillary services prices which have been derived on the basis of a market-based approach that takes the perspective of a producer. A producer has to decide whether to offer generation capacity as operational reserves to the system or, alternatively, use it for selling energy to the wholesale market. From a market perspective, a producer should therefore be neutral to either of these options when the income from reserve provision is equal to the expected income from the wholesale market. In a simplified way, the offers, at which a producer is willing to provide reserves, can be determined by taking into account the following cost items:

- Opportunity costs;
- Must-run obligations; and
- Additional wear and tear.

Please note that this market-based assessment excludes any fixed annual costs, but considers the incremental costs of providing reserves, including opportunity costs.

The simulations in the transmission and market model consider three types of ancillary services, i.e. automatically activated frequency containment and frequency restoration reserves (denoted as "Response (R1/R2)")[48], manually activated frequency restoration reserves ("Reserve (R3)") and replacement reserves with an activation time of several hours ("Back up"). Within the basic scenarios, all three products are exclusively provided by conventional generators, including hydropower and biomass. In contrast, the results presented below do not consider the potential provision of these services by variable RES-E and/or different types of demand response; this option is further discussion in Chapter 6. Nevertheless, it should be noted that the reserve and back up products are limited to the provision of additional outputs, whereas we have not considered the need for similar services for reducing production. Although the latter become increasingly important in power systems with a growing penetration of variable RES-E, these services can be easily provided by for instance wind and solar power at very limited costs.

Figure 110 provides a summary of the resulting prices of each product for the three main scenarios. This figure shows substantial variations between different scenarios and years, but especially between the first product and the other two services. The first product has the highest technical requirements that cannot be provided equally well by all technologies. Moreover, its provision is limited to spinning reserves, i.e. to units that are synchronised with the system and that operate at or above minimum stable level. Consequently, the first product is especially sensitive to must-run costs, i.e. when certain units have to continue and/or increase operation during periods of low prices. It is therefore not surprising to see that prices and volatility are the highest for this product. Indeed, a comparison with Figure 104 on p. on page 101 above reveals a certain correlation between average peak/offpeak spread in the wholesale market and average holding prices for this reserve product. This observation suggests that the high prices of this product, as well as the large volatility between different scenarios and years, are substantially driven by must-run costs.

Conversely, prices for the other two products are generally lower and show less variation in absolute terms. This observation is not surprising since these two products can be easily provided by both spinning and non-spinning units that are able to provide additional active power within the given time scales. At the same time, most scenarios are characterised by increasing production from RES-E, which displaces generation by other units, including flexible conventional plants. In combination with an increasing share of back-up capacities, this increases the availability of flexible resources and limits the costs of the corresponding services, especially for the third product. Nevertheless, prices may reach much higher levels during situations with tight margins and high wholesale prices, i.e. when back-up capacities are activated in the market.

48 Although these two products have different technical characteristics, we have combined them to simplify the analysis.

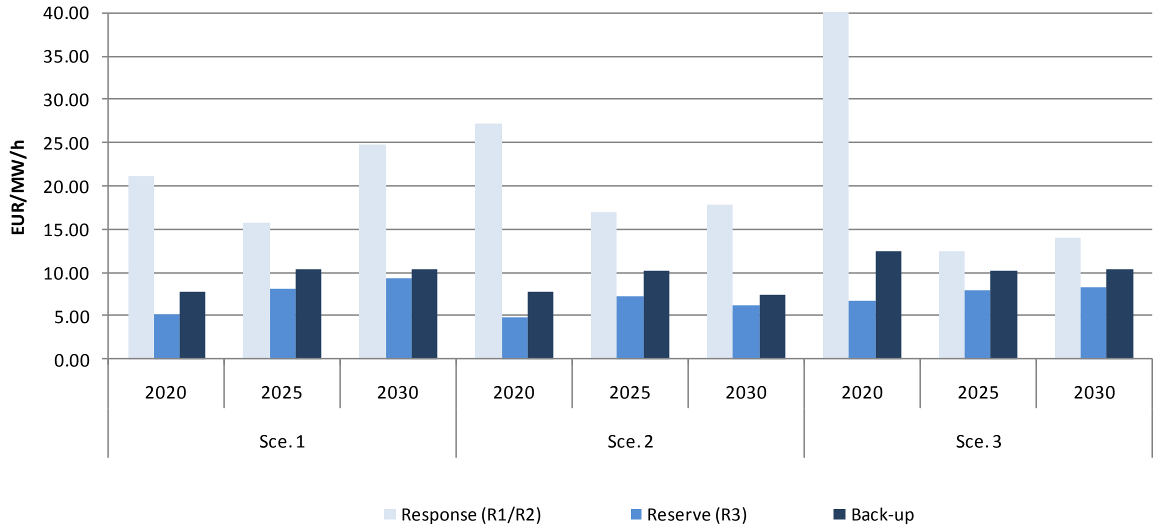


Figure 110 Average prices for operational reserves in the main scenarios

Figure 111 shows the corresponding results for the variations of Scenario 1. Again, prices for fast-acting spinning reserves are significantly higher than for the other two types of ancillary services. In contrast to the main scenarios, the results in Figure 111 furthermore show a clear trend towards increasing prices from 2025 to 2030, especially for fast-acting spinning reserves. Furthermore, we observe that prices for fast-acting spinning reserves are generally higher in the DG scenarios, at least in the year 2030.

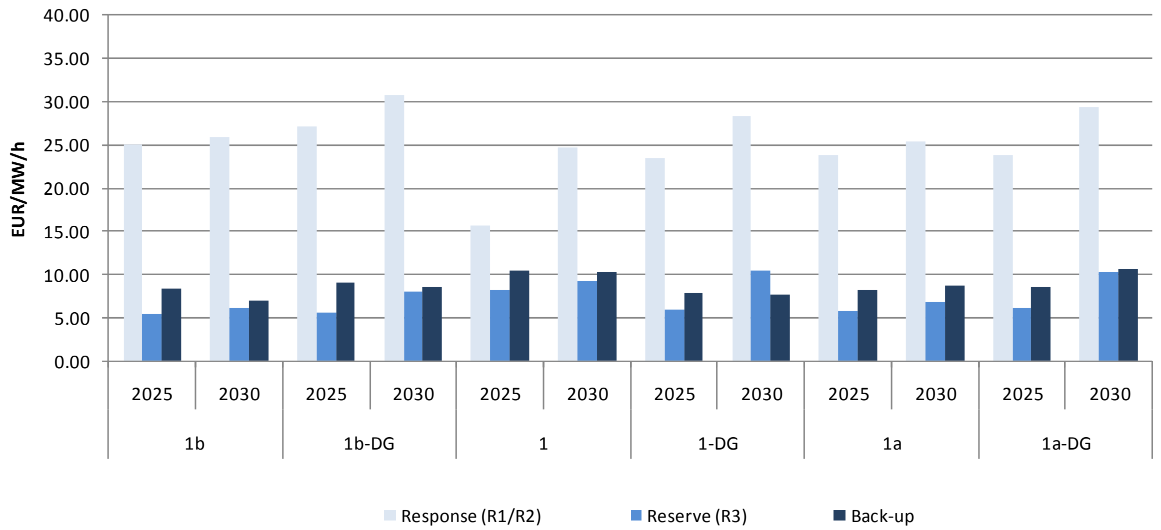


Figure 111 Average prices for operational reserves in the variations of scenario 1

5.3 Impact on Selected Generation Technologies

5.3.1 Operating Hours

Figure 112 below presents the modelled operating hours of conventional coal and gas-fired technologies as well as back-up and pumped storage across the three main scenarios. The figure shows capacity weighted average operating hours for both existing (old) and new gas and coal-fired generation. The figure shows that:

- Across all scenarios new coal and gas-fired plants tend to operate for more hours than the existing plants that we assume are less efficient and are therefore lower in the merit order;
- In Scenario 1, old coal and gas fired plants both operate at high mid-merit capacity factors, while new plants operate at baseload capacity factors. Towards 2030, operating hours for coal fired plants tend to increase, whereas operating hours for gas decrease for existing plants, but are relatively stable for new plants;
- In Scenario 2, coal and gas fired plants switch position in the merit-order due to the higher CO_2 prices, which reduces operating hours for coal and increases operating hours for gas;
- In Scenario 3, gas fired generators' operating hours increase across the modelling period, whereas coal fired generators' operating hours fall over time;
- Across all scenarios, back-up plants operate at very low capacity factors of less than 1% on average; and
- Pumped storage plants operate for between 200 and 1000 hours per annum, including the hours spent pumping and generating electricity. However, pumped storage plants tend to run more frequently towards 2030, as higher penetration of RES-E increases peak/off-peak spreads (see Section 5.2).

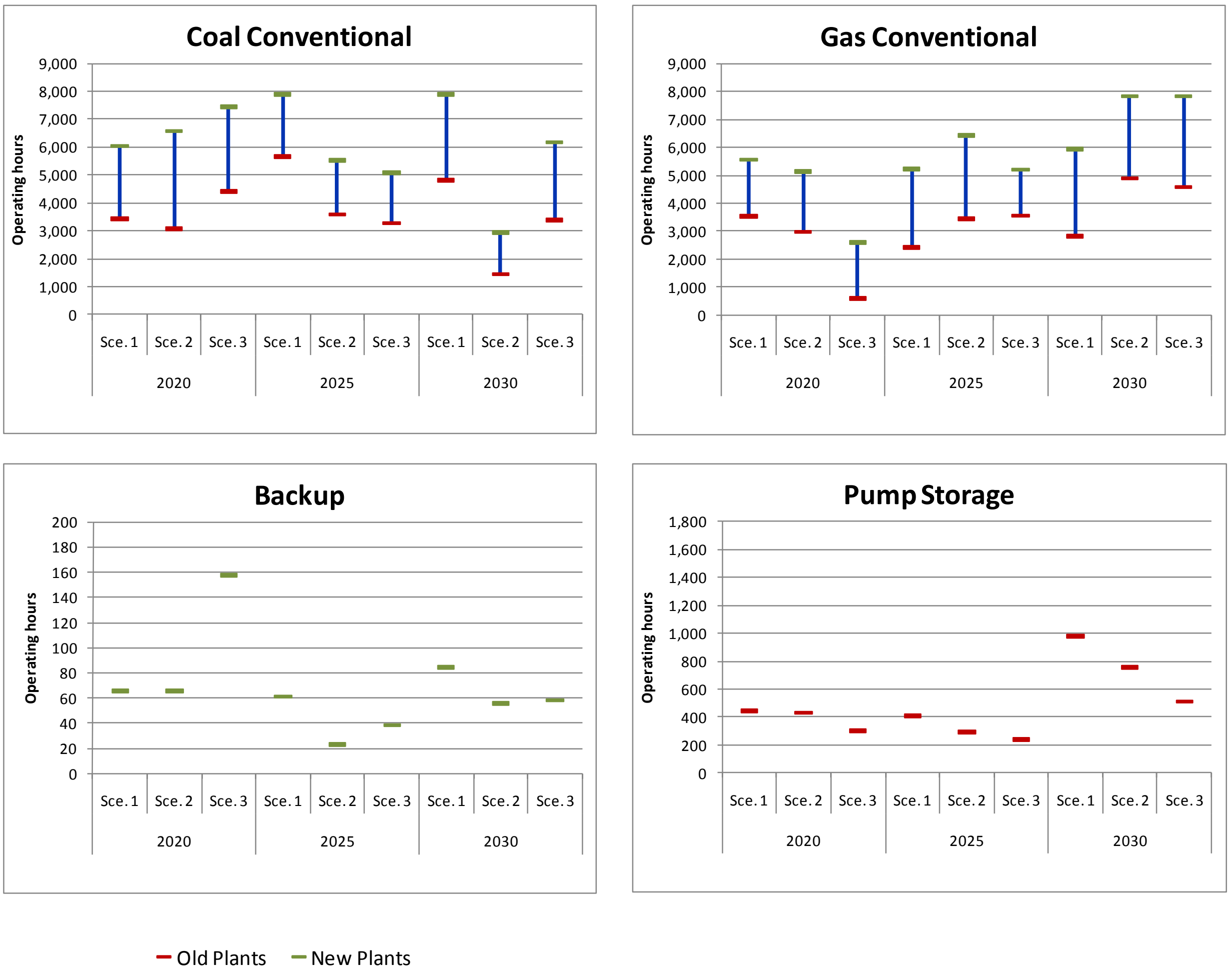


Figure 112 Capacity weighted operating hours for conventional plants in the main scenarios

As Figure 113 shows, we observe similar operating hours for coal plants across almost all the variations of Scenario 1. Conversely, we see more variation in the operating hours of gas-fired plants across the scenarios. As already noted above, coal plants generally run at higher capacity factors than gas-fired plants. As expected, back-up plants operate at relatively low operating hours across the modelling horizon, albeit increasing slightly in 2030. As described above, operating hours of pumped storage plants increase in 2030, particularly in the DG scenarios; but they still remain at very low levels.

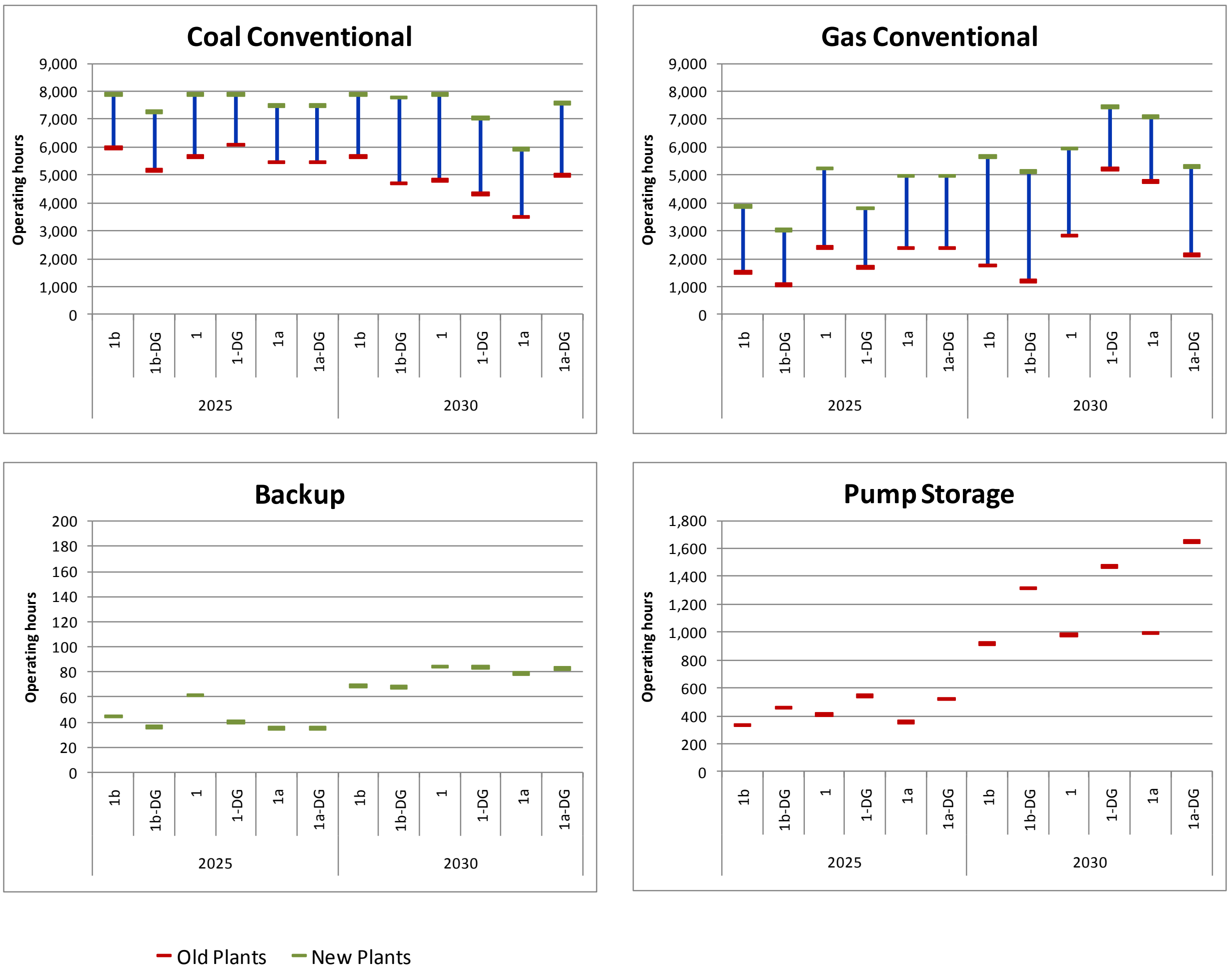


Figure 113 Capacity weighted operating hours for conventional plants in the variations of Scenario 1

5.3.2 Profitability

A key characteristic of a competitive market equilibrium is that the decisions taken by all market participants must be "incentive compatible". Essentially, this means that no market participant should be able to increase its profitability by deviating from the market equilibrium. For example, if new entrants come onto the system, then the market prices consistent with this outcome should provide the new entrant with sufficient revenues to cover both their variable and fixed costs, including a return on capital employed. Similarly, equilibrium market prices should not be high enough to allow more capacity to come online than the model suggests is efficient. Hence, the margins earned by new entrants should be just high enough to cover their assumed cost of capital.

A similar logic applies to existing plants. If existing plants cannot earn sufficient margins from market prices to recover their ongoing fixed O&M costs, then in a competitive equilibrium they should close down. Also, existing plants' upfront capital costs are sunk, so there is no reason that they must necessarily earn sufficient margins to cover the cost of capital on their historic capital expenditure.

As described in more detail in Section 5.2, the modelling framework employed provides an estimate of market prices resulting from a cost minimisation algorithm. Based on these price estimates and the generation dispatch determined by the market model, we have analysed the profitability of different generation technologies, taking into account the income from both the wholesale and ancillary services markets. As already explained in Section 2.4 it is important to bear in mind, however, that the modelling results are subject to certain limitations, mainly due to the interaction between different models and the necessary use of simplified assumptions. Moreover, the construction and dispatch of conventional generators, i.e. in particular coal plants and CCGTs, is also influenced by the assumed development of cogeneration, which may require certain plants to be built and/or operated even if they do not earn sufficient margins in the wholesale market. Consequently, the market prices presented in Section 5.2 above, as well as the modelled profitability of generators presented below, should therefore only be interpreted as broadly illustrative of market trends and may not be fully representative of how prices and generator profitability will develop over time.

5.3.2.1 Conventional generators

In order to assess the profitability of both new and existing plants, we estimate generation gross margins from the difference between revenue earned from modelled power prices[49] and the assumed fuel, CO_2 and variable O&M costs of each plant. As our detailed market simulations are limited to three target years, we compare gross margins against fixed O&M costs and – for the case of new plants - annualised capital costs. In a first step, we do only consider revenues from the energy market, whilst we comment on additional income from the provision of ancillary services below.

Figure 114 provides an overview of the resulting gross margin for coal plants and CCGTs in the three main scenarios. This depiction reveals considerable variability with regards to the distribution of annual gross margins across different years and scenarios for both technologies. In addition, it shows the following general trends:

- Both technologies are generally able to recover at least their fixed O&M costs across the entire time horizon. Consequently, there seem to be sufficient incentives for existing plants to remain in operation, although some plants may face problems especially in the year 2020.
- On average, gross margins of coal plants remain too low to recover the capital cost of new plants. Moreover, they remain roughly constant in scenarios 2 and 3, whereas they increase significantly from 2020 to 2025 in scenario 1.
- In contrast, CCGTs are benefitting from a marked increase of gross margins in all three scenarios. Consequently, whilst the average CCGT is clearly unable to recover its capital costs of new capacity in 2020, average margins seem to justify investments into new capacity in 2030.

These results, which reflect the underlying assumptions on the development of fuel and CO2 prices and thus different from the current situation in Europe[50], indicate that existing plants seem to be able to operate profitably in all scenarios. Nevertheless, they also seem to contradict the development of the generation structure as presented in Section 4.2 above. For instance Figure 59 on p. 55 has shown that, when neglecting OCGTs, incremental investments are dominated by CCGTs in scenarios 1 and 2 but by coal plants in scenario 3. Similarly, it may appear surprising that coal plants seem to earn the highest margins in Scenario 1, which has the highest share of RES-E.

In this context, it is important to note that the generation expansion model considers the entire time horizon until the year 2050, whereas the results of the market model reflect current fuel and CO_2 prices in each year. As a consequence, market outcomes and generator profitability may deviate from long-

49 Please note that hourly market prices have been capped to a value of € 10,000/MWh in the analysis below.

50 As already mentioned in Section 4.5.1 all three scenarios are characterised by increasing CO_2 prices, which lead to a fuel shift from coal to natural gas as well as higher operating hours and increasing income for gas-fired plants.

term trends in the short term.[51] For the case of relative high margins of coal plants in scenario 1, for example, this perceived contradiction mainly reflects the development of fuel and CO_2 prices in the PRIMES scenarios (compare Section 3.5). Scenario 1 has relatively low coal and CO_2 prices in the period until 2030, but high natural prices. As already pointed out when analysing operating hours in Section 5.3.1 above this improves the competitiveness and leads to an increased use of coal plants in the time horizon until 2030. At the same time, the decarbonisation scenarios 1 and 2 are characterised by drastically increasing CO_2 prices post 2030, which makes coal a much more expensive option than CCGTs in the long term. Consequently, it is still economic to invest into CCGTs but to temporarily increase the use mainly of existing coal plants until 2030.

Similarly, natural gas gets substantially more expensive than coal post 2030 in scenario 3 („Current Policy Initiatives"), whereas the increase of CO_2 prices remains limited. Investments into coal plants are hence a preferred option in the long term in scenario 3, although they appear to be less competitive in the short term.

51 The modelling framework in this project is based on the notion of perfect foresight, i.e. investment decisions into new coal plants and CCGTs are taken under perfect knowledge of the future development over the entire lifetime of a given plant.

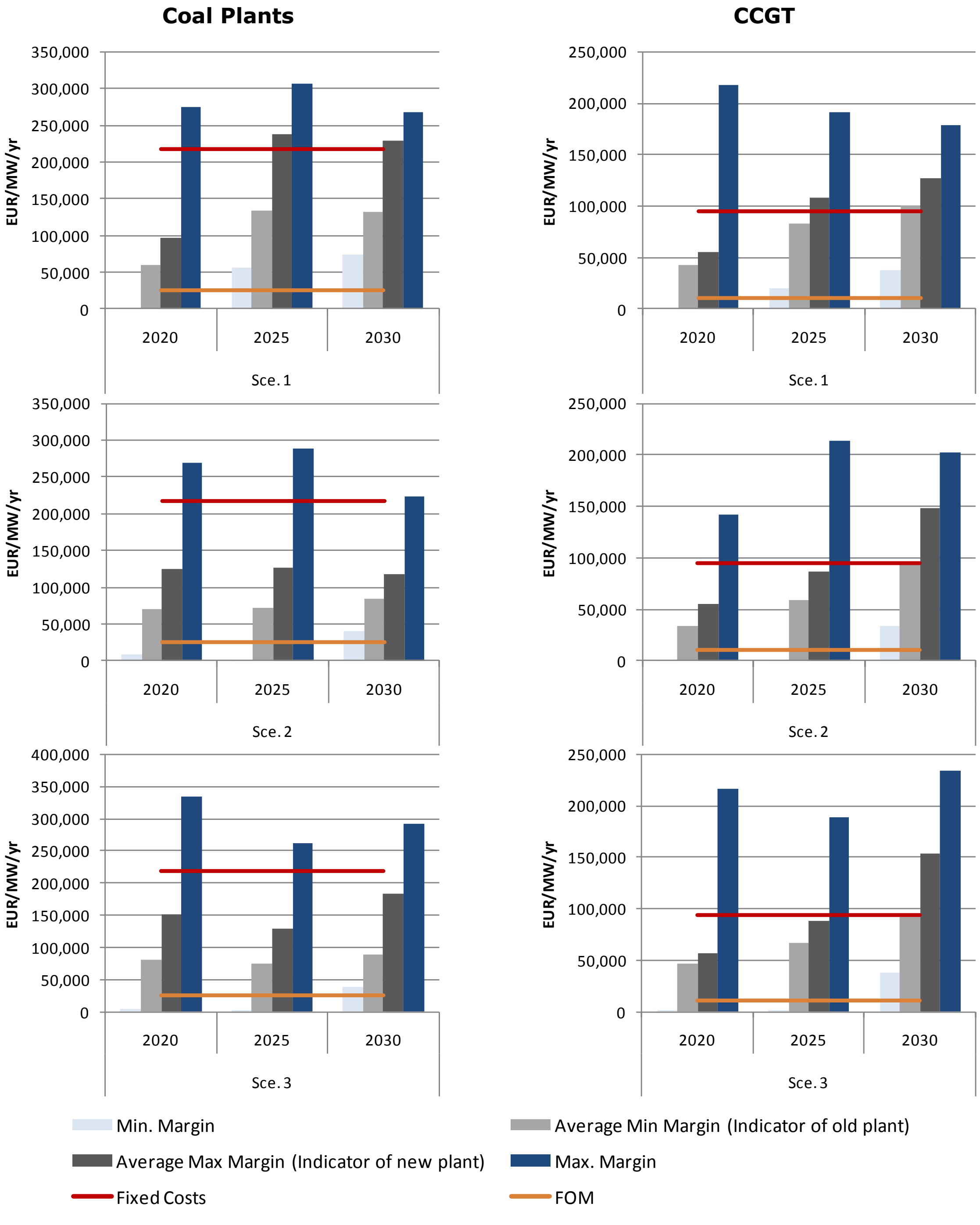


Figure 114 Gross margins from wholesale market revenues of coal- and gas-fired plants in the main scenarios

Although these results thus seem to be broadly consistent with the longer term evolution of the European electricity supply sector until the year 2050, the results presented so far reflect "snapshots" of individual years only and do not differentiate between existing and new plants in detail. We have therefore analysed the profitability of new conventional plants using scenario 1 as an example. To do this, we retrieve data from the model on the gross margins earned by generation technologies that the model has the option to build: coal generation, CCGTs, and OCGTs. As the modelling focuses on sample years, we calculate annual gross margins between 2025 and 2030 by linearly interpolating modelled gross margins between these years, but assume constant margins thereafter until each plant has reached the end of its economic lifetime. This analysis examines the profitability of only those plants that the model chooses to build, in the locations where it chooses to build them, so the realised rates of return on investment that we present should (in a market equilibrium) equal the WACC.

Figure 115 contains histograms representing the distributions of modelled internal rates of return (IRRs) for new coal plants and CCGTs. It shows that as compared to the target of 10%, there is a very wide distribution of modelled returns for both technologies. Moreover, whilst CCGTs achieve an average rate of return that is close to the target of 10%, the average return of coal plants is less than 50% of the target rate. To some extent, this may be due to the fact that the results shown in Figure 114 do not take into account the development post 2030 but are based on a simple extrapolation of the situation in the period from 2025 to 2030. Consequently, these results may still be consistent with the investment decisions, i.e. although the corresponding plants are not immediately profitable in the period until 2030.

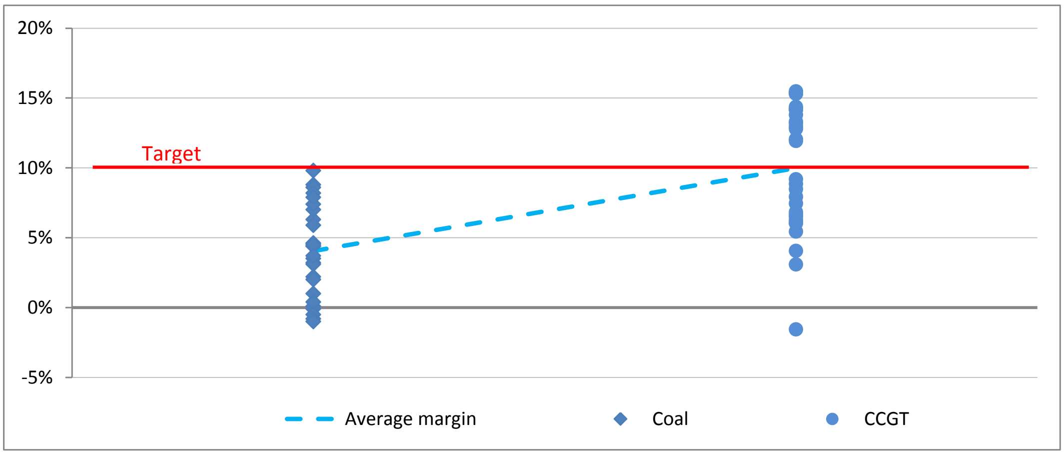


Figure 115 Modelled rates of return for new coal plants and CCGTs in scenario 1

Nevertheless, the results shown in Figure 114 clearly are not consistent with the theoretical prediction that all new entrant technologies should earn returns equal to their cost of capital. We therefore believe that these differences do also reflect the limitations stemming from the necessary simplifications and interfaces between different models in the analytical framework we have used. As already mentioned in Section 2.4, the market prices presented in Section 5.2 above, as well as the modelled profitability of generators, should therefore only be interpreted as broadly illustrative of market trends and may not be fully representative of how prices and generator profitability will develop over time.

These limitations should also be taken into account when interpreting the gross margins of OCGTs and pump storage plants that are shown by Figure 116. This figure shows that, on average, OCGTs (back up capacity) are able to recover their fixed O&M costs but that they fail to recover their capital costs. Although the situation improves towards the year 2030, average margins still remain the annualised costs of new plants. Moreover, a more detailed analysis of individual plants reveals an extremely wide distribution, with some plants earning much more but others far less than their fixed costs.

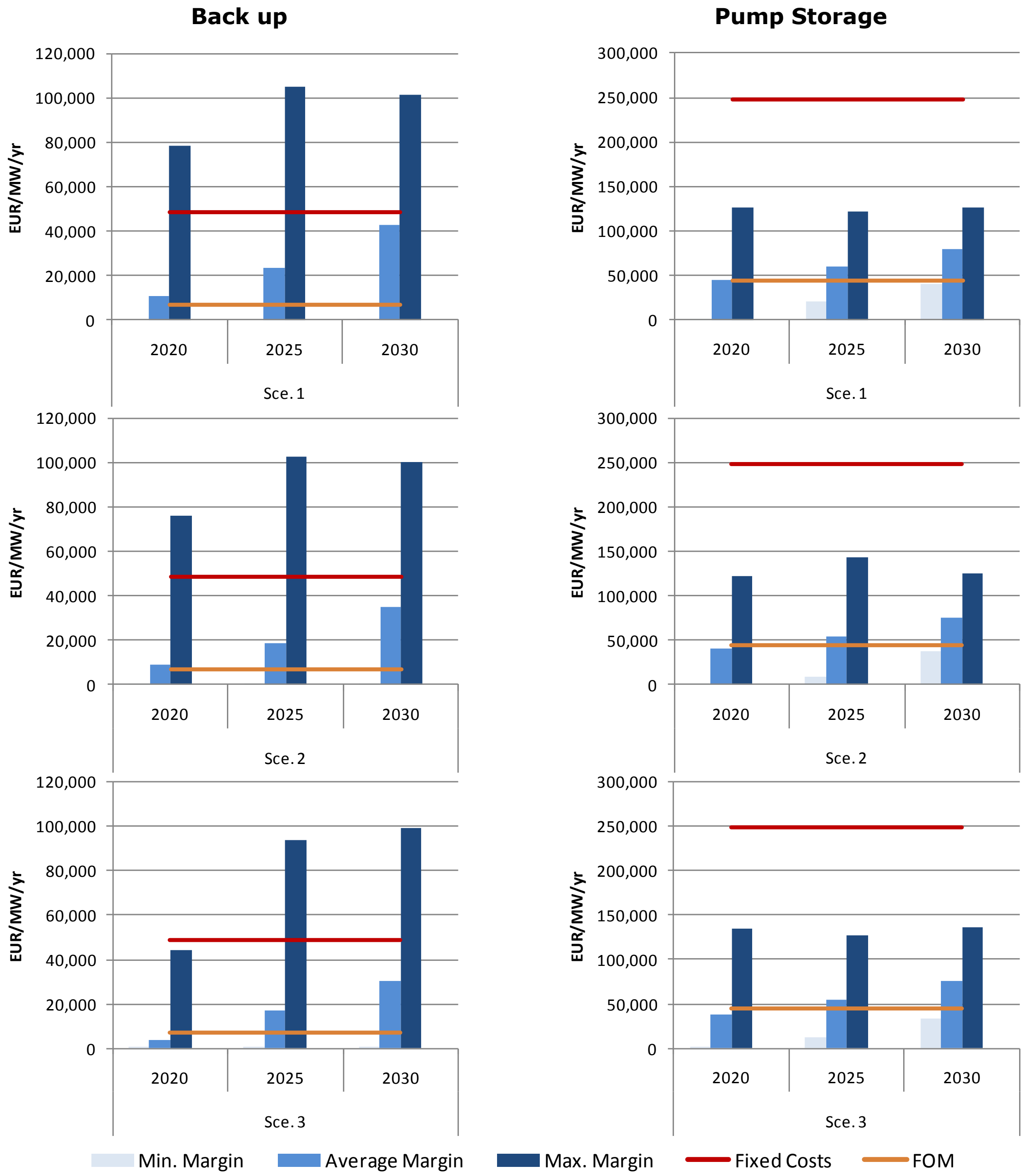


Figure 116 Gross margins from wholesale market revenues of back up and pump storage plants in the main scenarios

Conversely, Figure 116 clearly shows that achievable margins of pump storage plants clearly remain below the fixed costs of new plants, although they suffice to compensate for fixed O&M costs. In general, this observation indicates that investments into new pump storage plants do not seem to be commercially justified within the scenarios and time horizon considered by this study, whereas existing plants appear to operate profitably.

Our framework also allows us to derive prices for ancillary services from modelled energy prices. Again, in a competitive power market equilibrium, we would expect generation capacity to be allocated efficiently (i.e. to achieve a least-cost outcome) between the production of energy and the provision of ancillary services. In such an equilibrium where an optimal allocation between these markets is achieved, we would expect the marginal value of energy in the two markets to be the same. As explained in Section 5.2.2, we can derive prices of ancillary services on the assumption that they remunerate generators for the opportunity cost of using their capacity to provide energy, i.e. the margin they would have obtained from the energy market had they not been providing ancillary services.

Based on the ancillary services prices so determined and the allocation of operational reserves to different generators, we have also estimated the potential income from the provision of ancillary services. Figure 117 provides an overview of the results for coal plants, CCGTs and OCGTs in the three main scenarios, whereas Figure 118 provides the same results for the variations of Scenario 1.

Similar to gross margins earned from the wholesale market, both figures show that annual revenues from ancillary services vary widely for various technologies, scenarios and years. Again, these differences reflect considerable variations in market prices and the provision of ancillary services by different technologies in different parts of Europe.

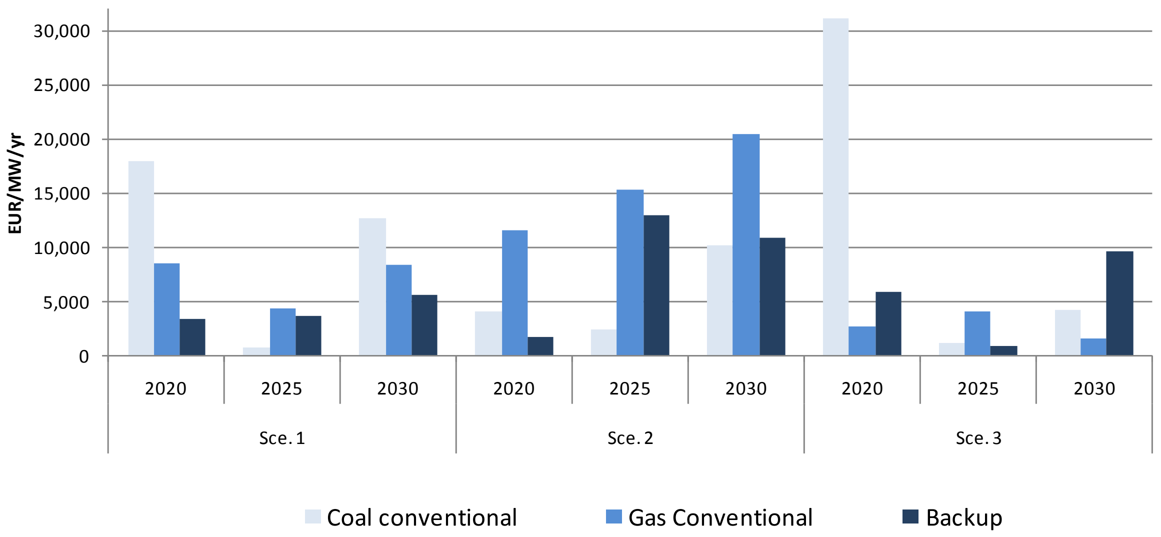


Figure 117 Average gross margins from ancillary services (Scenarios 1, 2, 3)

Secondly, Figure 117 and Figure 118 also show that all three technologies may obtain significant additional margins from participation in the ancillary services markets. However, compared to gross margins from the wholesale market, additional revenues are relatively small. Consequently, whilst the provision of ancillary services may help improving the profitability of conventional generators, sufficient income from the wholesale market will be decisive especially for coal plants and CCGTs.

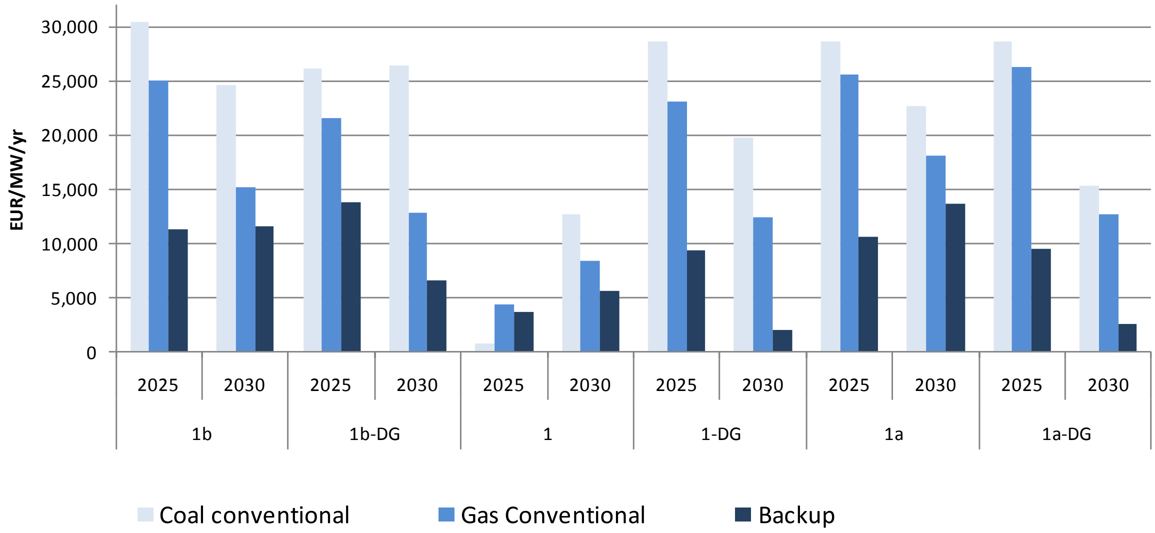


Figure 118 Average margins from ancillary services for the variations of Scenario 1

5.3.2.2 Renewable generation capacity

Despite the caveats associated with the modelled power prices cited above, it is still possible to make an approximate assessment of whether the overall levels of modelled power prices, which primarily depend on the assumed levels of fuel and CO_2 prices, are high enough to cover the costs of various RES-E technologies.

Figure 119 compares the gross margins calculated from our modelling results to the fixed O&M and annualised capital costs for onshore and offshore wind and solar PV, with two different scenarios (optimistic and pessimistic) on solar PV costs. The figure shows that:

- Onshore wind power plants in many market zones seem to be able to recover their fixed costs in the market, even without subsidies, in both 2025 and 2030. However, in reality the profitability of individual plants depends on local variation in costs and wind yields, so some plants in more remote locations that are costly to access, or areas with relatively low wind speeds might not be profitable without subsidy;
- In most scenarios and in most market zones, the cost of offshore wind remains higher than the market value of its production. This suggests that most offshore wind projects will continue to require subsidy over the period to 2030. However, in Scenario 3, which has a limited share of RES-E and relatively high fuel and CO_2 prices, the market value of its output approaches its fixed costs in some market zones by 2030; and
- The fixed costs of solar PV remain higher than our assumed fixed costs across the modelling period. However, if we assume faster reductions in PV investment costs (the “optimistic” case shown by the dashed line), by 2030 modelled market prices allow solar PV developers in a number of market zones to cover their costs in scenarios 2 and 3. As for wind plants, however, the profitability of individual plants depends on local costs and solar yields.

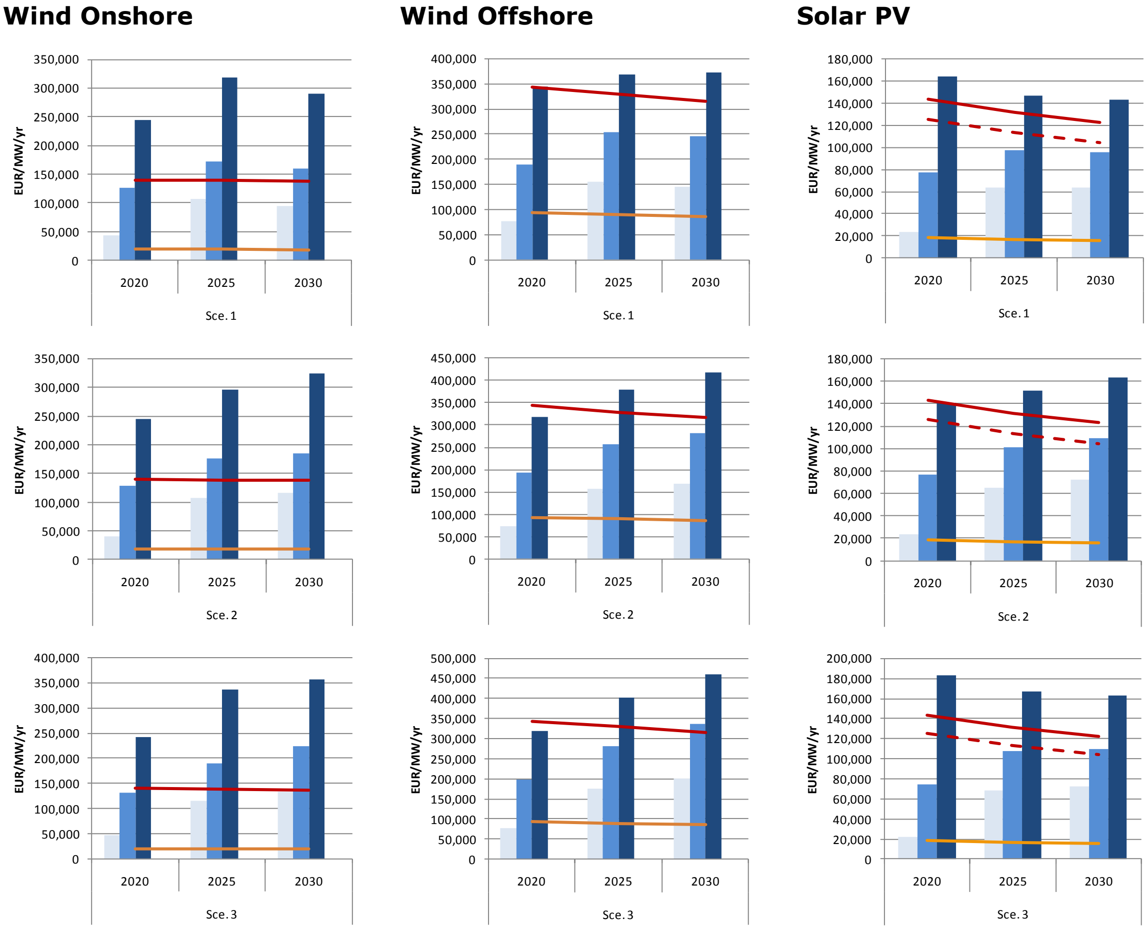


Figure 119 Gross margins of selected RES-E technologies in the main scenarios

Results charts for the variations of Scenario 1 are provided in Figure 122, which shows similar results to the figures shown here. However, in the decentralized variations, average margins for PV are lower compared to scenario 1, as significantly higher shares of PV are installed in these cases which supresses prices during daylight hours when PV is producing.

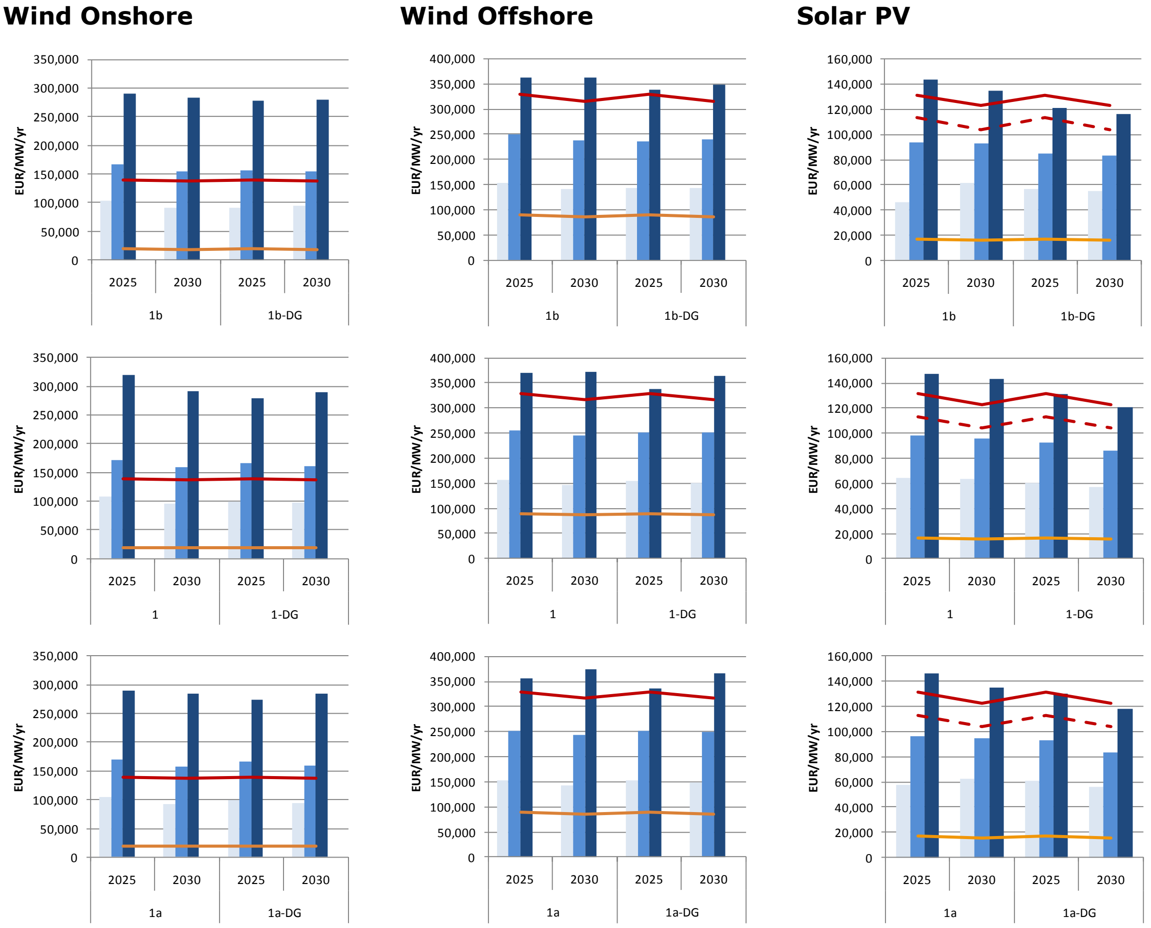


Figure 120 Gross margins of selected RES-E plants in the variations of scenario 1

5.4 Potential Barriers for Investments into Electricity Generation and Storage

This Section discusses some important issues and relevant drivers influencing the scope for sufficient investments in generation infrastructure and assesses potential barriers for necessary investments.

As the penetration of renewable power generation increases, the role of conventional power generation capacity will change, running fewer operating hours as they are pushed down the merit order, their periods of running will be less predictable, and they will become more dependent on peak energy prices to earn the margins required to cover their fixed operating and investment costs. Increasing reliance on short-lived price spikes in periods of scarcity might increase the risk profile of generation investments, which will ultimately affect the financing costs they face. Increasing price volatility created by the variability of RES-E may also reward more flexible generation, which is able to react more quickly to changing market conditions.

As discussed in Section 5.3.2, we have undertaken a detailed profitability analysis of conventional and renewable generation technologies.

Our analysis indicates that all existing technologies are able to recover their fixed O&M costs across the whole modelling range. Moreover, our results indicate that certain investments into new conventional plants may be profitable, although some plants seem to find it difficult to recover their investment costs. However, the time horizon between 2020 and 2030 is characterised by a situation where existing capacity margins from conventional plants are gradually reduced in response to the strong growth of RES-E, whilst very limited new capacity is required. Moreover, the profitability analysis is limited to snapshots of the years 2020, 2025 and 2030, whereas generation expansion considers the full time horizon until the year 2050. Consequently, it would not be safe to draw strong conclusions on the extent to which conventional generation technologies are able to recover their fixed O&M and construction costs due to the complications associated with robustly forecasting power prices.

Therefore, any suggestion from the modelling results that prices do not remunerate investment in new capacity should not lead to the conclusion that the energy market will not remunerate investment in the generation capacity required to integrate RES-E into the EU power system efficiently. While is it true that some inefficiencies in energy markets may undermine the efficiency of investments taken by participants in the energy market, these inefficiencies have not been modelled within our framework, which fundamentally assumes a well-functioning energy market.

Despite the difficulties of forecasting energy prices, our analysis does suggest that the profitability improves for renewable technologies towards 2030. Still, the overall level of power prices over the period to 2030 will remain too low, given our assumed fuel and CO_2 prices to remunerate investments in most RES-E technologies. This suggests that subsidies will continue to be required to support the scale of RES-E development assumed in this study.

6 ASSESSMENT OF POSSIBLE TECHNICAL MEASURES

6.1 Introduction

In the previous sections, we have already referred to a number of potential technical and/or regulatory measures, which may help to support the successful integration of large amounts of (decentralised) generation from RES-E into the power system and market. In this chapter, we present and discuss a number of technical measures that may be considered, in order to facilitate the integration of RES-E and/or to reduce the associated costs.

In summary, we consider the following measures in this chapter:

- Measures related to generation, storage and load:
  - Enhanced operational characteristics of conventional generators;
  - Design of RES-E plants;
  - Centralised and decentralised storage;
  - Demand response;
- Operational measures for dealing with the variability of RES-E:
  - Improved forecast accuracy of variable RES-E;
  - Regional sharing of reserves and balancing services;
  - Provision of ancillary services by RES-E;
- Measures related to transmission:
  - Use of alternative transmission technologies;
  - Improved network monitoring and control;
  - Construction of overlay grids;
- Measures related to distribution:
  - Reverse operation of distribution circuits;
  - Active distribution grids / Smart grids;
  - Restricted operation and curtailment of decentralised RES-E.

For some of these measures, we have carried out additional simulations of one or more of the scenarios described. The corresponding assumptions and results are always presented and discussed in the context of the corresponding measure.

6.2 Generation, Storage and Load

6.2.1 Enhanced operational characteristics of conventional generators

More flexible conventional generation

With an increasing penetration of renewable technologies, characterized by variable generation profiles, the role of conventional generators will change considerably. As renewable generators have relatively low variable costs, such plants will be dispatched ahead of conventional thermal generation capacities (notwithstanding rules for priority dispatch, etc.). At the same time, conventional generation capacities will continue to play a role in the future power systems at least in the time horizon considered by this study. Apart from the provision of firm back up capacity, conventional power generators will still be required to supply residual load, which is not yet covered by RES-E. Nevertheless, conventional units will be required to adjust their output depending on generation from non-controllable renewable generators to instantaneously meet residual electricity demand. As fluctuations in renewable generation can be high in terms of size (MW) and speed (MW/min.) of variation, conventional plant will be required to operate with a high degree of flexibility in order to effectively accommodate the increasing requirements.

Compared to operational characteristics of the current fossil generation portfolio, improvements in the following areas might be required to ensure system security, while integrating large amounts of RES-E:

- Part load operation:
  - Most of the currently installed conventional generation infrastructure has been designed for full load generation. At this operating point, power plants have the highest operational efficiency. With increasing penetration of fluctuating renewables however, conventional generators will be required to more often operate in part-load mode to compensate for short-term variations in renewable generation (i.e. in times of high RES-E output). Running plants at even lower output levels for short periods of time compared to today, may prove economic compared to the alternative of shutting down and re-starting the plants. At the same time part load efficiencies need to be sufficiently high to reduce part load emissions and ensure profitable operation at low output ranges.
- Load changes:
  - In fossil fuel dominated power systems, the requirements for load changes of generators due to changes of electricity demand are modest. However, in power systems with high shares of variable RES-E, the need for fast response to considerable changes in RES-E generation requires conventional plants to adjust output levels in short periods of time. High ramp rates of conventional steam and CCGT plants are therefore essential to enable such technologies to follow residual demand in a fast and effective manner. In addition, it needs to be ensured that high ramp rates for both increase and decrease of production can be maintained across the while output range.
- Start-ups / shutdowns:
  - Frequent unit start-ups and shutdowns increase operational costs and have a negative impact on plant lifetime, particularly if the plant has not been designed for such behaviour. Instead of running units at minimum stable output levels for an extended period of time, shutting down a unit and restarting the same at a later point of time might be more economic. In order to perform such operational strategy, however, start times need to be small to ensure technical

feasibility. Furthermore start costs for both O&M as well as starting fuel, need to be low to ensure economic viability.

- Minimum up and minimum down times:
  - Conventional power plants require certain minimum up times (after unit start) as well as minimum down times (after unit shutdown) to reduce fatigue behaviour of plant cycling. Similar to staring behaviour discussed above, frequent cycling has a negative impact on maintenance costs and plant lifetime. However, in systems with high penetration of fluctuating resources, frequent start-ups and shutdowns may be required by individual generators. Relaxing technical restrictions on minimum up and down times will improve load following behaviour of the generation portfolio by allowing generation resources to be utilized more economically. Instead of operating several units at minimum stable level for an extended period of time, some units might be switched off and re-started. Such operation of the production portfolio if technically feasible will help reducing the requirements for part-load operation at lower operational efficiency and therefore reducing fuel consumption and carbon emissions.

Provision of spinning reserves from pump storage plants

Due to their high operational flexibility, pump storage plants are generally well suited for the provision of ancillary services such as spinning reserves, including primary, secondary and tertiary control. Pump storage plants offer a very valuable source for such reserves, as they are able to quickly adjust their output, enabling a very high regulation quality. For this reason they are usually ideal candidates especially for the provision of secondary and tertiary control as both products require high scales of power adjustments and ramp rates. However, traditional pump storage are generally able to provide these services in the production model but not whilst pumping.

In a system dominated by large amounts of fluctuating generation, such as wind and solar power, the need for flexibility for system balancing is likely to increase. Pump storage plants might therefore be a valuable source to meet these increasing requirements. In this context, however, it is important to note that pump storage plants have traditionally been equipped with constant speed control, meaning that these machines are not able to adjust their pumping load on a continuous basis, but rather in discrete steps. Consequently, the ability of such plant to provide spinning reserves whilst in pumping mode is limited. The market however, has realized the importance of variable speed pump storage plants and several new or retrofitted pump storage plants are equipped with such technology.

Next to this important limitation of operational flexibility, it is important to further mention some general limiting factors for the provision of spinning reserves from pump storage plants. In general, pump storage plants without natural inflow have smaller hydro reservoirs compared to conventional storage plants. Pump storage plants are therefore usually used for short-term activities (within a day or week). For such plants, the reservoir size sets the operational limit (i.e. the duration for operation – generation or pumping - at full capacity). Operation is furthermore constrained by the need to pump water back into the upper reservoir, which means that it does not usually allow for continued production for an unlimited period of time, or only at the expense of not being able to use some or all of its pumping capabilities during that time.

Overall, whilst pump storage plants are technically well suited to the provision of spinning reserves, operational constraints imply that the utilisation of these capabilities is normally limited to a few hours per day. In the following we comment on the ability of pump storage plants to provide certain types spinning reserves:

Primary and Secondary Frequency Control

Pump storage plants offer a very good source for primary and particularly secondary frequency control as they are able to quickly adjust their output, enabling a very high regulation quality. However, as we noted above, these two services are normally only available in the generation mode, and to some extent also in pumping operation for variable speed pump-turbines.

When we take the operational constraints mentioned above into account, this implies that pump storage plants are typically not used to provide these services throughout the whole day. Furthermore, it is important to note that PS plants with a small reservoir also face energy constraints. Whilst this is not relevant for the provision of primary frequency control, it may become important if a significant (net) volume of secondary frequency control has to be provided over an extended period of time, i.e. several hours. which may create severe restrictions on the provision of secondary frequency control from pump storage plants.

Most importantly, however, both primary and secondary frequency control can only be provided when the plant is synchronised with the system. As a result, a pump storage plant may face opportunity costs of having to sell its output below peak prices not only for the volume of reserves provided, but also for the minimum level of production ("minimum stable level"), which may significantly increase the (opportunity) costs of reserve provision. Similar opportunity costs issues arise for reversible pump-turbines when providing such reserves in pumping operation.

Tertiary Reserves

Many of the considerations mentioned for the case of primary and secondary frequency control principally also apply to the provision of tertiary reserves. However, this is subject to some important variations. Again, the dynamic flexibility of these plants makes them a very suitable source of fast-acting reserves. Moreover, tertiary reserves may also be provided in the pumping mode for variable speed pump-turbines (spinning reserves), or in form of their whole capability to start pumping (non-spinning reserves), which basically extends the availability of this reserve to the entire day. However, traditional pump-turbines with constant speed can usually only be operated at a few discrete levels of capacity. As a result, these pump storage plants are usually not able to offer flexible volumes of reserves and balancing energy in the pumping mode, except they are equipped with variable speed machines.

Similar to the case of secondary frequency control, pump storage plants with a daily reservoir face energy constraints when providing tertiary reserves. But in this case, these restrictions are likely to be more critical as the probability of tertiary reserves which are being activated for an extended period of time may be much higher than for secondary frequency control.

Due to the typical daily operating cycle of a pump storage plant, negative reserves (i.e. a reduction of output) may be provided at no (or only very limited) cost during hours with high electricity prices (peak hours), and positive reserves (i.e. an increase of generation) during offpeak hours with low prices. In contrast, the provision of positive reserves during those peak hours where the pump storage plant normally operates, results in certain opportunity costs (depending on the pattern of the daily price profile in the wholesale market). The same holds true for the provision of negative reserves during night / offpeak hours, in this case further aggravated by the pumping losses. Overall, the provision of spinning reserves from pump storage plants may be highly economic during certain hours, whereas it may result in excessive costs during other hours.

6.2.2 Technology improvements of RES-E plants

Apart from the design of conventional plants, the integration of variable RES-E may also be facilitated by technology improvements and changes to the design of RES-E plants. As further discussed below (compare Sections 6.3.3 and 6.5.2), RES-E may themselves contribute to system security, either in the form of an explicit provision of ancillary services or by complying with stricter connection requirements, requiring enhanced fault ride-through capabilities or active and reactive power control.

In addition, further benefits may also be achieved due to other improvements in the basic design of modern wind and solar plants. For illustration, Figure 121 shows the development of average capacity factors for wind turbines over the past decade. Besides a substantial increase of capacity factors over time this Figure 121 also reveals the emergence of a new class of wind turbines that have been specifically designed for areas with lower wind speeds. Although low-wind turbines are typically more expensive than other turbines designed for high-wind-speed sites, they enable the use of locations with less favourable wind conditions.

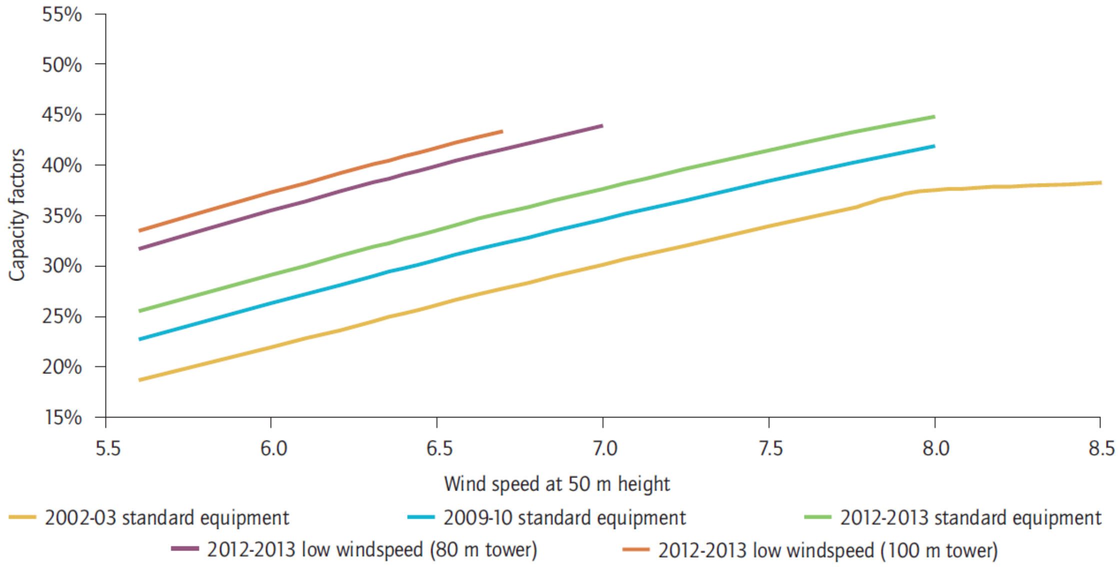


Figure 121 Capacity factors of selected turbine types

Source: IEA[52]

From the perspective of system integration, increasing capacity factors and the use of low-wind-speed turbines offer a number of important advantages:

- Increasing capacity factors improve the ratio between available output and installed capacity. It is thus possible to reach the same level of production with less capacity. This in turn reduces peak production. Ceteris paribus, this will increase the feasibility of exporting excess production to other regions and reduce the residual curtailment of wind power.
- At the same time, these effects will also lead to an increased utilisation of transmission capacity for exporting excess power. This again may help to reduce the need for incremental transmission capacity.
- Depending on the frequency distribution and utilisation of periods with lower wind speeds at different locations, higher capacity factors may furthermore increase the share of firm capacity that can be

52 IEA. Wind Power Technology Roadmap 2013 Edition. Paris. 2013

provided by RES-E. Ideally, this should also allow decreasing the volume of conventional back up capacity.

- Low-wind-speed turbines facilitate the construction of wind turbines at inland locations that are closer to demand but which often have less favourable wind conditions. As illustrated by the load-driven scenario (compare Chapters 3.4.1 and 4), locating RES-E closer to demand centres may offer significant savings in terms of infrastructure requirements and operating costs.

Overall, these considerations clearly show that further technology improvements for RES-E may lead to significant benefits not only for the owners and operators of the corresponding plants, but equally for the whole power system.

6.2.3 Centralised and decentralised storage

One of the technical options to meet the need for more flexibility of the electricity system is the use of energy storage. Principally, a set of basic technical parameters determines the functions storage technologies can perform:

- Power rating [kW/MW]: (maximum) power supply of a storage facility;
- Energy rating [kWh/MWh]: (maximum) energy a storage facility can store;
- Response rate [Seconds/Minutes]: reaction time of a storage facility when dispatched;
- Technical efficiency [%]: ratio between the energy input and output of a storage technology.

Both power and energy rating of storage facilities give rise to a notion of size: Whereas the power rating essentially determines the voltage level in the network on which it will be connected (and the corresponding functions in the system), the energy rating determines the type of storage cycle it can be employed for. A quick response time is needed for storages employed as a balancing reserve; technical efficiency is the crucially measure for operational cost. Table 22 gives an overview of different functions energy storages can fulfil in the electricity system and available storage technologies. Storages are classified according to their power rating and storage cycles. Short storage cycles refer to ancillary services storage can provide, such as frequency control and secondary reserves. Hourly storage cycles correspond both to classical peak shaving and integration of variable RES-E (by offsetting imbalances arising from smaller errors of weather forecasts). Additional storage functions arise from temporary or seasonal weather conditions: The former refers to weekly cycles for extraordinary weather conditions, such as prolonged sunny periods leading to excessive solar power generation, the latter to the seasonal differences in wind and solar power supply due to differences in wind speed and sun radiation.

From a technical viewpoint the challenges for system stability arising from the cyclical imbalances of electricity feed-in described above can be met on all voltage levels: Small scale community storage, corresponding to the distribution network, can be used, for example, to off-set differences of solar feed-in over 24 h. Similarly, utility scale storage can be used, e.g., for off-setting unpredicted changes in wind generation. Traditional pump storage and other types of centralised storage finally can provide different functions.

Table 22 Different types of electricity storage and their functions

Cycle	Function	Community scale storage	Utility scale storage	Bulk storage
		0,25 - 100 kW	**0,25 - 10 MW**	**50 - 1.000 MW**
Days/ Weeks	Saisonal storage for balancing weather-based over- and undersupply of RES-E based electricity feed-in			*Power-to-Hydrogen, Power-to-Gas*
	Balancing extraordinary weather situations (4-7 Days)			*Power-to-Hydrogen, Power-to-Gas*
Hours / Days	Load shifting / Peak shaving (4-8 h) RES-E integration (15-60 min)	Batteries	Batteries	Pump storage, CAES
Minutes / Hours	Balancing Reserve Capacity (<15 Minutes)	Batteries	Batteries Fly-Wheels	Pump storage, CAES
Seconds / Minutes	Saisonal storage for balancing weather-based over- and undersupply of RES-E based electricity feed-in			*Power-to-Hydrogen, Power-to-Gas*

Note: Pre-commercial technologies in italics

Today, energy storage in the electricity system is mainly based on pump storage technology. Pump storage can be categorized as centralised storage and is usually marketed both in wholesale and balancing markets. Traditionally, the function of hydro based storage is peak shaving: cheap offpeak electricity, generated by nuclear or coal plants, is transformed into valuable peak load electricity, typically on a daily basis. As discussed in the Section 6.2.26.2.1 pump storage plants are furthermore well suited to deliver ancillary services. Pump storage plants are mainly connected to transmission or subtransmission networks.

Today, only compressed air energy storage (CAES) can approximately match its functions in the system. In Europe, there is currently one non-adiabatic CAES plant operational, with a number of pilot-projects exploring innovative and efficient adiabatic plants.

In addition, a number of technologies are on the brink of market maturity; others are currently developed and tested in pilot-facilities. Many battery technologies (as well as flywheels) count among the former; future cost digression as well as increasing prices in balancing markets could possibly lead to their mass deployment.

Traditionally, electricity storage has been limited to hourly and daily storage. In order to provide weekly and seasonal storage, two technologies are currently being explored in pilot projects: Power-to-Hydrogen and Power-to-Gas (with “gas” referring to methane). In the case of the former, power is transformed into hydrogen via electrolysis; however, transport and storage of hydrogen remain technically challenging and expensive. Therefore, experts have brought forward the idea of a further transformation of hydrogen to methane (natural gas). The existing energy infrastructure is a clear advantage for the Power-to-Gas technology; however, the low efficiency of the transformation process from electricity to gas makes the process more costly prices.

Storage costs vary considerably: from technology to technology, but also from storage plant to storage plant – in particular in the case of pump storage and CAES, installation cost depend to a large extent on the geographic conditions on site of construction. Note that there are different measures of specific cost for storage, relating to the different notions of size of storage, i.e. power and energy rating.

Table 23 gives an overview over ranges of power and energy cost of different technological options for storage, as well as information on market maturity and deployment. The figures give an indication of the variation across technologies; however, they have to be interpreted with care: Prior to market maturity, cost estimations remain vague, and in the case of mature, but hardly deployed technologies mass deployment can be expected to reduce cost considerably.

Table 23 Assumptions on cost of electricity storage

	Power cost [€/kW]	Energy cost [€/kWh]	Maturity	Deployment
Pump Storage	500-3600	60-150	Mature	Widespread
CAES	400-1150	10-120	Mature	Limited
P-2-H	550-1600	1-15	On-going research	Limited
Flywheel	100-300	1000-3500	Mature	
Supercapacitor	100-400	300-4000	On-going research	Widespread (small scale)
Lead-acid	200-650	50-300	Available	Widespread
NiCd	350-1000	200-1000	Available	Limited
Li-ion	700-3000	200-1800	Available	Growing for small scale application
NaS	700-2000	200-900	Pilot projects	Deployment for Japan
ZEBRA	100-200	70-150	Currently commercialised	
Vanadium Redox Flow	2500	100-1000	Early commercialisation	

* Source: Vasconcelos, J. et al. 2012[53]

It is often argued that electric storage represents an important precondition for the integration of large volumes of RES-E into the power system. More precisely, electric storage facilitates the balancing of fluctuating production from RES-E as well as variable consumption. As a result, storage may allow for a more efficient use of other production technologies and/or to reduce the need for peak production capacity as well as network expansion at the transmission and distribution level. At the same time, investments into new storage plants have so far remained limited, with the exception of additional pump storage capacity.

It is beyond the scope of this project to carry out a detailed analysis of different storage technologies. Moreover, the possible effects and benefits basically depend on a limited number of key technical properties, which may be considered similar for different technologies. In our analysis we have therefore focussed on a limited set of storage combinations, which are characterised by the ratio between their power and energy rating, the round-cycle efficiency, and their connection level (i.e. transmission vs. distribution). We have furthermore analysed (novel) storage technologies, which may potentially make significant additional storage capacity and volumes available, whilst we will pay less attention to an incremental increase of traditional hydropower plants. More specifically, we have considered the following cases:

- **Centralised storage**: Electric storage that is typically connected to transmission and high voltage grids and which has similar characteristics as traditional pump storage, i.e. with an efficiency of approx. 75% and a discharge duration of several hours (e.g. 8 h); noting that this group is also broadly representative of several battery technologies and compressed air electric storage (CAES);
- **Decentralised storage**: 'Novel' applications of electricity storage that are used at the distribution level and which have similar technical characteristics as centralised storage, such as batteries; and
- **Power-to-hydrogen ("P-2-H")**: Electric storage with an intermediate efficiency (e.g. 50%) and large storage volumes (e.g. allowing for more than 1 month of uninterrupted use of peak capacity), such as the use of hydrolysis in combination with the injection of hydrogen into the natural gas network.

53 Vasconcelos, J. et al. (2012) "Electricity Storage: How to Facilitate its Deployment and Operation in the EU", Final Report in the EU THINK project

The first two cases are broadly equivalent to each other, except for the voltage level at which they are connected. In line with the construction of the different generation scenarios, we have assessed the application of centralised storage in the basic scenario 1, but have combined the application of decentralised storage with an increased penetration of DG in scenario 1-DG. In both cases, we have added additional pump storage plants to specific locations in the generation and transmission model. The geographical distribution of additional storage capacity has been derived from an analysis of wholesale market prices and incremental infrastructure requirements (transmission and back up generation) in the basic scenario, both with unconstrained and delayed transmission expansion.

A similar approach has been chosen for the P-2-H option. In contrast to the two other cases, however, we have not added storage capacity to the model. Instead, we have represented P-2-H by means of adding interruptible demand to the model. The operational parameters of this interruptible demand are set such that load will be increased at low prices, but be interrupted when the cost of hydrogen are higher than the alternative use of natural gas[54].

Table 24 below provides a summary of the total number, capacity and storage volume of the additional storages, which we assume in the three different sensitivities. The corresponding assumptions have been derived as follows[55]:

- For 'Centralised storage', we have assumed that storage plants with a capacity of 23.8 GW, representing 50% of currently installed pumps storage capacity in the Member States, will be added to the system by 2030. Additional storages are installed in regions that show high volatility in electricity prices[56]. The total capacity is allocated to individual regions in proportion to final electricity demand.
- For 'Decentralised storage', we have assumed that 10% of all solar PV installations connected to the low voltage grid (60% of total installed PV capacity or 377 GW) will be equipped with battery storage. On this basis we have assumed an installed storage capacity of 22.5 GW with round-cycle efficiency of 90% and a storage capacity equivalent to four full operating hours.
- For ‘P-2-G’, we have assumed the same amount of installed capacity as for 'Centralised storage'. We furthermore assume that this technology is only used in selected regions (i.e. 11 regions in Germany, Great Britain, Ireland & Spain) that are characterised by at least 1,000 hours with excess supply in the sensitivity 'Delayed transmission expansion'. The total storage capacity is distributed to these regions in proportion to the aggregated wind and PV capacity.

Table 24 Assumptions for storage sensitivities in the EU-28

Sensitivity	Number of plants / regions	Installed capacity (GW)	Storage capacity (GWh)	Round-cycle efficiency
Centralised storage	43	23.8	190	75%
Decentralised storage	64	22.5	90	90%
Power-to-Hydrogen	11	23.8	N/A	N/A

54 The costs of hydrogen are equivalent to the current wholesale electricity prices divided by the efficiency of hydrolysis. Conversely, the alternative corresponds to the price of natural gas (in €/MWh), plus the cost of CO_2 released due to the production of electricity from electricity. For instance for scenario 1, this results in a 'strike price' of approx. 35 €/MWh for electricity.

55 These assumptions have been chosen with a view to assume sufficiently large variations from the basic scenario. We emphasise that these assumptions are not intended to represent an expected development and that they may indeed by considered overly optimistic with regards to the penetration and efficiency of new storages.

56 Based on a ranking of the total annual income of according to 3h daily electricity price spreads, two-thirds of the most profitable regions were identified.

Figure 122 below presents the physical infrastructure development of the analysed storage sensitivities compared to the corresponding reference scenarios. These results indicate that savings in transmission grid expansion due to application of storage technologies are small.

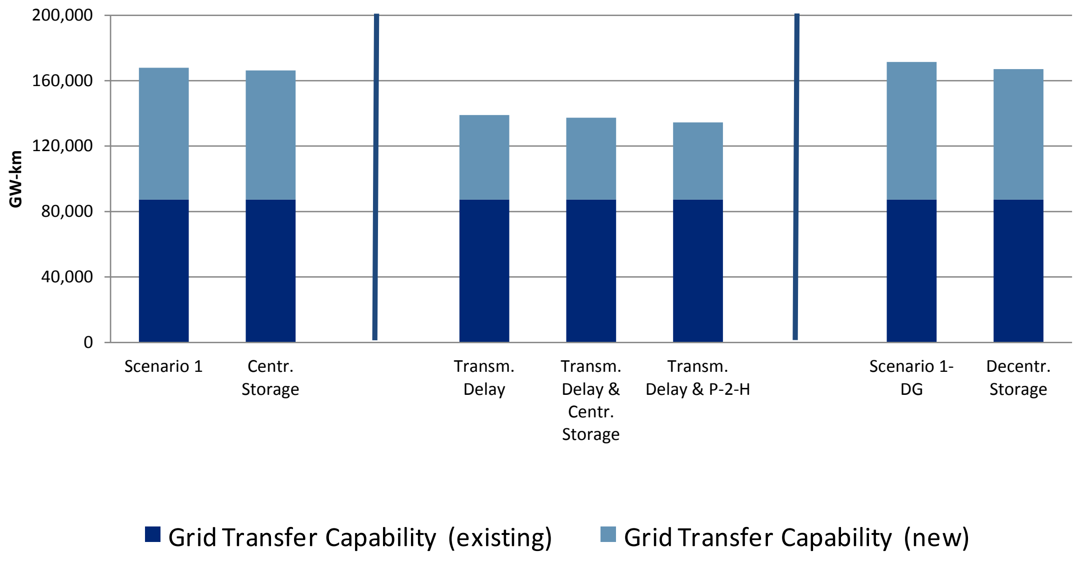


Figure 122 Development of Grid Transfer Capability for the storage sensitivities in 2030

However, a notable reduction of renewable curtailment can be identified across all modelling scenarios, particularly in sensitivities with delayed transmission development, see Figure 123. The analysis shows that storage of electricity on the basis of longer cycles via power-to-hydrogen is an effective measure to reduce renewable curtailment. In this context it should be noted, that any storage technology incurs conversion losses in the process of storing and releasing electrical energy as presented in Table 24 above[57]. These conversion losses basically need to be accounted for, when calculating the effective curtailment of renewables, as presented in Figure 123. In most cases, conversion losses remain much lower than the reduction in RES-E curtailment, however, such that the overall net benefit is positive.

57 For P-2-H we assume a conversion efficiency of 90% for the production of hydrogen and an average efficiency of 58% for reconversion into electricity in CCGT plants, resulting in overall losses of approximately 48%.

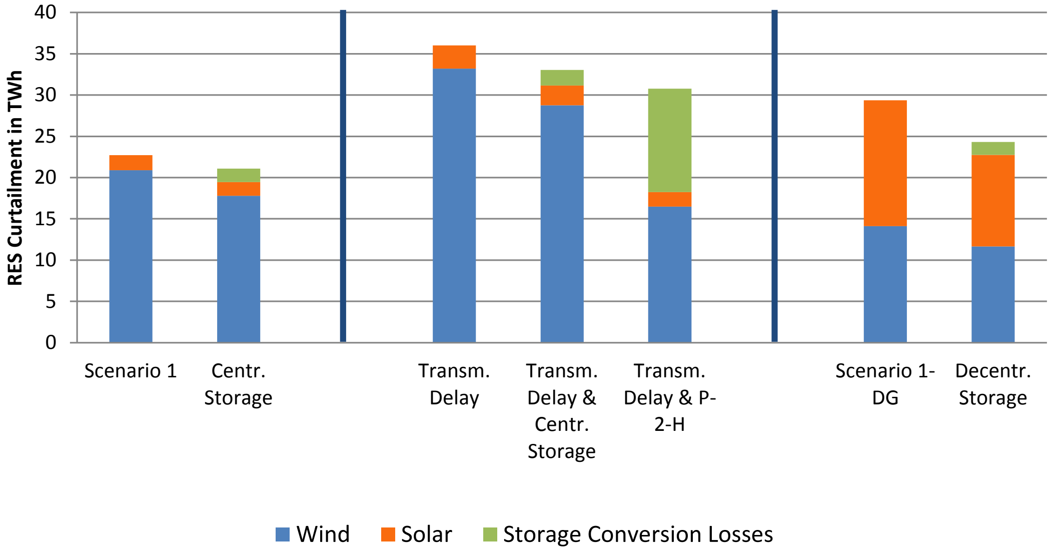


Figure 123 Curtailment of RES-E for storage sensitivities in 2030 (EU-28, in TWh)

While the impact of storage technologies on average wholesale prices is limited, electricity peak/offpeak ratios decrease in sensitivities with centralized and decentralized storage as presented in Figure 124. This effect is mainly caused by increasing consumption in low demand periods and consequently higher electricity prices, while storage production in high price periods generally reduces high electricity peak prices. However, P-2-H has a less notable effect on price ratios. The process consumes conversion electricity in low price periods and consequently increases electricity prices. However, as the converted hydrogen is mainly used in existing gas fired plants, no additional generation capacity compared to the reference case is available to replace expensive generation (e.g. in gas fired GTs). Consequently peak prices remain at the same level as in the reference case, while offpeak prices increase in the regions with P-2-H only.

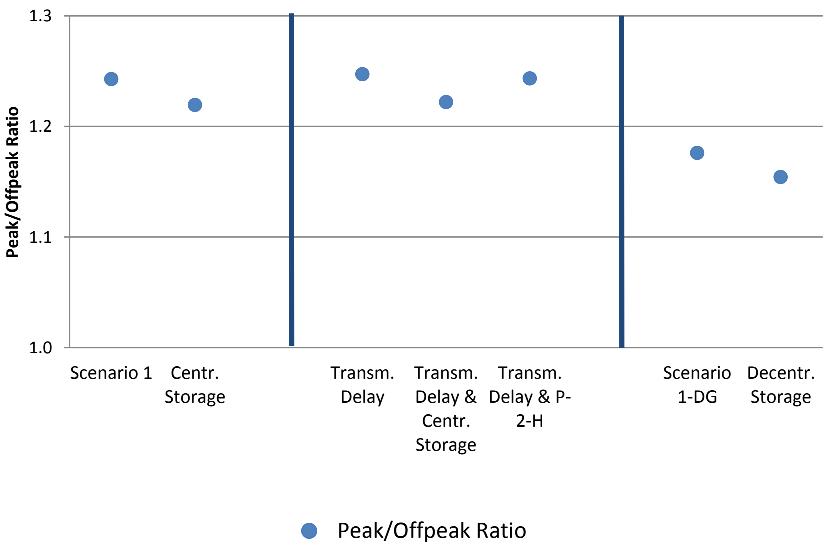


Figure 124 Peak/offpeak ratios for the storage sensitivities in 2030

Modelling results indicate that some savings in back up capacity can be achieved by adding centralized and decentralized storage capacity to the system, while savings in transmission infrastructure are limited. The additional capacity from storages is effectively able to partially replace back up capacity and to contribute to system security. However, the requirements for back up in the P-2-H sensitivity increase as P-2-H is not adding capacity to the system, whereas the economics of exporting from the corresponding areas decrease such that less transmission is being built.

As centralised storage does not impact the necessary distribution reinforcement, distribution costs for the sensitivities including central storage remain on a constant level. In case of decentralised storage, which was assumed to be installed depending on the concentration of solar PV per region, costs of distribution network reinforcement are decreasing by around € 3bn This substantial cost reduction is related to the additional benefit of the storage devices which are capable not only to eliminate overload caused by backflows during high infeed of DG-RES, but also by storing electricity for peak demand hours.

More interestingly, modelling results presented in Figure 125 indicate that storage contributes to reducing overall system costs in case of low investment costs. Based on the cost figures presented in Table 23 above, we have calculated aggregated costs including back up, transmission, distribution, generation OPEX components as well as cost ranges for investment costs for storage technologies (based on the values presented in Table 23). If we assume an optimistic development of centralized storage costs (e.g. by retrofitting of existing pump storage plants), storage tends to reduce overall system costs. A more conservative or even pessimistic cost development however, is likely to increase overall costs above the level of the reference case.

For decentralized storage technologies, we can identify a decrease in overall system costs even for a moderate development of storage investment costs. Our analysis shows that P-2-H technologies increase overall system costs, even considering an optimistic development of investment costs assumptions.

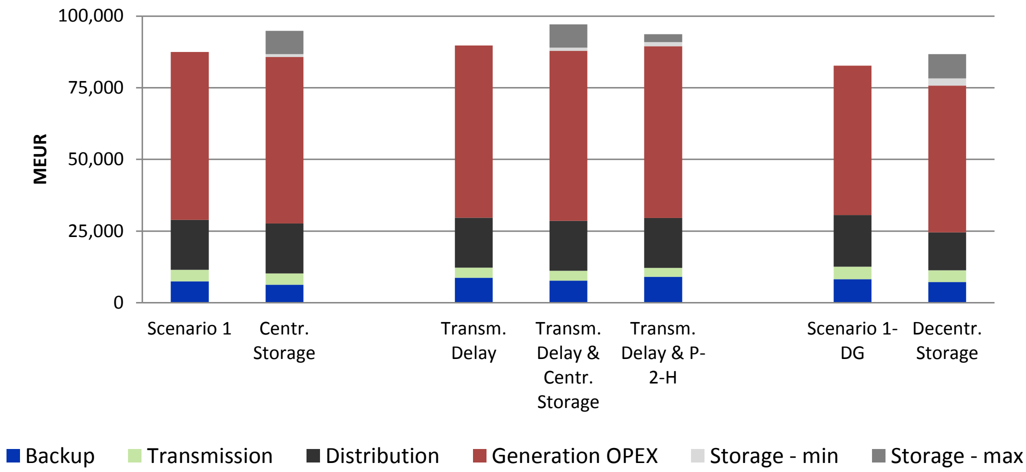


Figure 125 Summary of selected annualized investment and operational costs for the storage sensitivities in 2030 (EU-28, in MEUR)

Investment costs in EUR/kW (min / max): Centralized (400 / 3600); Decentralized (700 / 3000); P-2-H (550 / 1600)

6.2.4 Demand Response

Demand response (DR) represents another potentially important source of flexibility in the power system. DR generally allows for a short-term shift of electricity demand only. Any decrease or increase in consumption will usually have to be compensated in several hours, whilst it is not normally possible to shift demand over a longer time. In a way, DR is thus similar to traditional pump storage, but with a much higher round-cycle efficiency of close to 100%.

In practice, DR offers different functionalities:

- Load reduction;
- Load shift;
- Load increase;
- Ancillary services.

The first option, reduction of load, represents a temporary load reduction not causing another load increase. This case is characteristic for industrial consumers with a high capacity factor reaching a level of close to one. By reducing the energy consumption during a certain period, the production process is reduced or stopped for a certain period. After this period production continues as before which means that the electricity consumption reaches the level of the period before. In this case no additional consumption occurs after DR takes place, as industrial demand does not exceed the continuous consumption level. Conversely, consumption is shifted to a later time in the second case, which means that demand will increase at that time. Finally, DR can also serve as a provider of ancillary services, including in particular different types of operational reserves.

The first two cases of DR are currently expected to offer the main cost reduction potential, while the third option represents a future possibility for power systems with a high penetration of DG-RES and a high share of flexible demand, such as HPs and EVs. However, DR may also help to increase the availability of ancillary services significantly, especially during periods where limited volumes of positive reserves are available from conventional power plants.

For the quantitative analysis, we have defined several scenarios with a given set of assumptions on the maximum power (MW) and energy (MWh), which can be shifted by DR within a single day. For the distribution analysis, we have furthermore taken assumptions on the distribution of the total DR potential between different demand segments, and hence on different voltage levels. In order to limit the complexity of the analysis, however, we have not explicitly considered the ability of DR to contribute to the provision of ancillary services.

In practice, the potential for DR is likely to vary significantly between countries. To both limit the complexity of this particular sensitivity and provide a better view of the impact of DR on infrastructure requirements, we consider three different cases:

- A low DR scenario, with the ability to shift up to 7.5% of the daily peak load and 5% of daily consumption (based on scenario 1);
- A high DR scenario, with the ability to shift up to 15% of the daily peak load and 10% of daily consumption (based on scenario 1); and
- A high DR scenario for the sensitivity with an increased penetration of heat pumps and EVs, with the ability to shift up to 15% of the daily peak load and 10% of daily consumption (based on the sensitivity case explained above).

Figure 126 shows the curtailment of RES-E for the different DR sensitivities. For the sensitivities based on Scenario 1 on the left, a minor impact of DR on the already low level of curtailment of solar PV is visible. Conversely, the reduction of wind curtailment is substantial, but shows a decreasing incremental benefit as the volume of DR increases. In the case of the sensitivity with HP’s & EV’s, the overall curtailment is reduced by almost 50%. Again the major reduction concerns wind energy, although curtailment of solar PV is also reduced significantly.

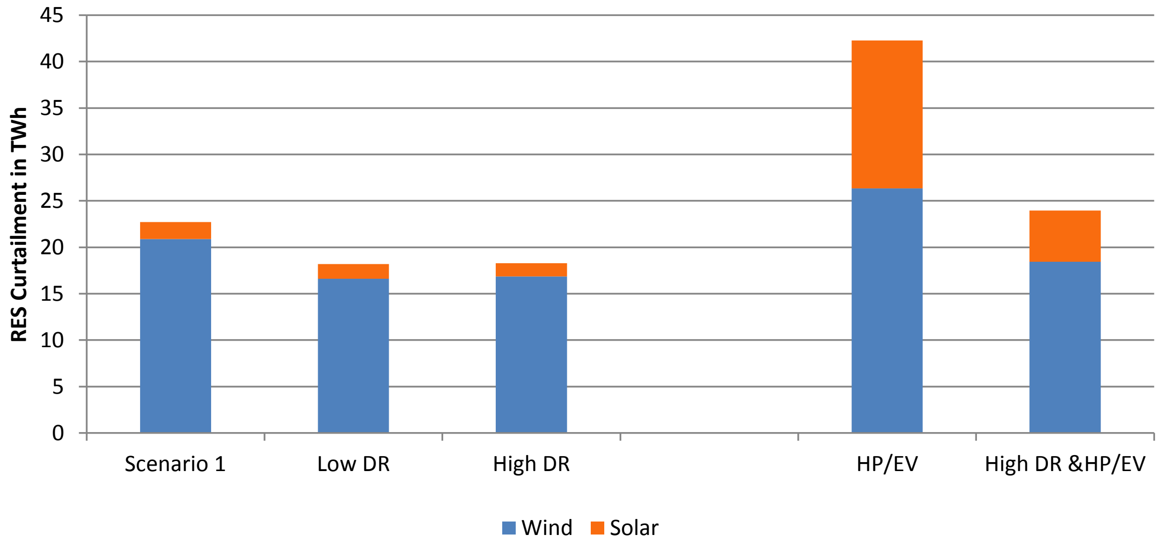


Figure 126 Curtailment of RES-E for the DR sensitivities in 2030 (EU-28, in TWh)

Figure 127 illustrates the range of electricity wholesale prices in the EU-28 on the left and the peak/offpeak ratios on the right. An increasing level of demand response leads to higher level of wholesale prices. This can be explained by the shift of consumption from periods with high electricity demand to periods with lower electricity demand, partially removing periods of very low electricity prices.

Not surprisingly the peak/offpeak ratio decreases for higher levels of DR. Looking at the prices in more detail, the flattening of the price curve is obviously driven by the lift of the offpeak prices to a higher price levels, while peak prices stay comparably constant. For the sensitivity case of High DR & HP/EV an European average peak/offpeak ratio of close to zero is visible. This surprising result is related to the wide range of individual peak/offpeak ratios in the Member States, reaching from 0.9 to around 1.35, with ratios of less than 1 representing inverse peak/offpeak ratios. This clearly shows the different effects of DR for varying demand and generation profiles. Additionally the reduced information value of a differentiation in peak and offpeak prices becomes obvious for power systems dominated by variable RES-E and flexible demand. In these cases, differentiation between periods of low and high demand respectively RES-E generation would represent a more appropriate index in the future.

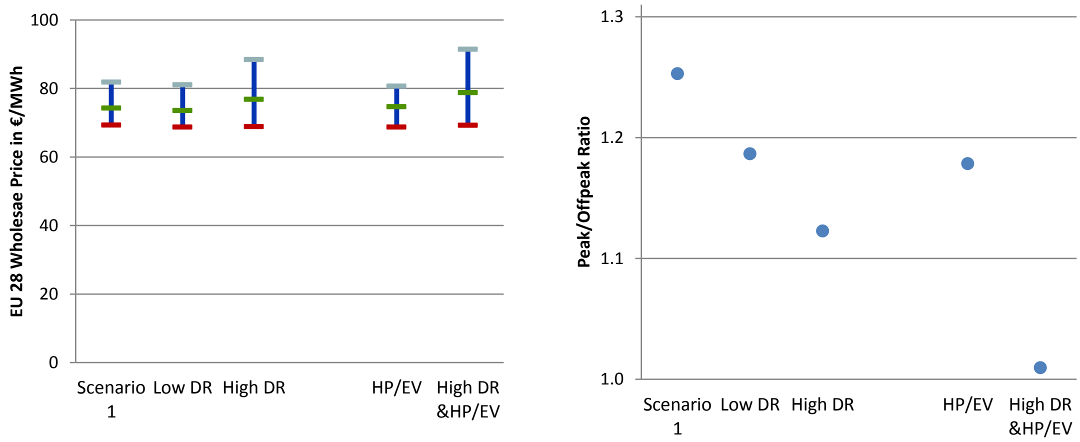


Figure 127   Annual wholesale prices and peak/offpeak ratios in the DR sensitivities in 2030

Figure 128 shows the impact of DR on the costs of distribution reinforcements for the DR sensitivities. In the sensitivities based on Scenario 1 on the left, distribution reinforcement costs are decreasing almost linearly, reaching a level of less than € 100bn. For the sensitivity with HPs and EVs, a high level of DR substantially reduces the cost of reinforcement of distribution grid (30%).

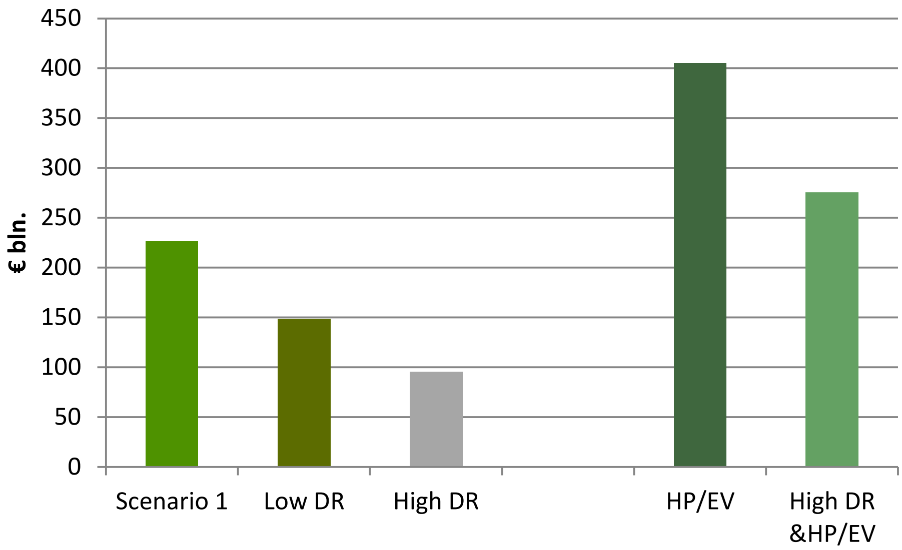


Figure 128   Impact of DR on the costs of distribution reinforcement in 2030

Figure 129 summarises the annual costs of incremental investments and generation OPEX. Whilst Figure 129 does not show the costs of DR, it indicates that the net benefits of demand response will remain positive at least for those types of DR that can be used and activated at limited costs. Moreover, Figure 129 also illustrates that the benefits of DR are particularly large in combination in situations with larger differences between peak and trough load, such as in case of heat pumps and electric vehicles.

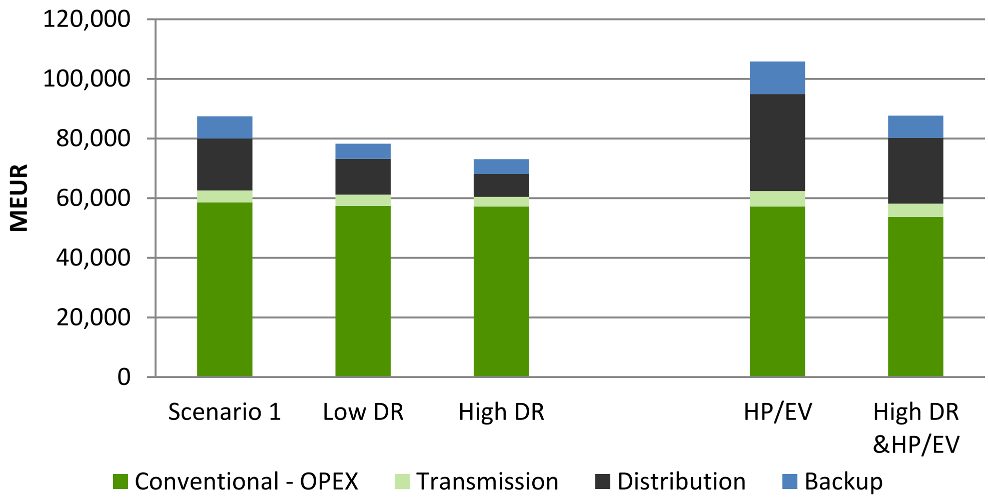


Figure 129 Annualised cost components in 2030

6.3 Operational Measures for Dealing with the Variability of RES-E

In order to ensure system security in real time, system operators make use of ancillary services, including in particular operational reserves. Although the detailed definitions and technical properties of such operational reserves vary widely, they essentially serve for dealing with unforeseen events and developments in real time. Traditionally, the dimensioning of operational reserves has been mainly driven by the risk and possible size of generation outages, load forecast errors and minor fluctuations of demand in real time, also known as load noise. With an increasing penetration of RES-E, however, the variability of these resources becomes increasingly important. Conversely, RES-E plants may themselves contribute to the provision of ancillary services and thus help to mitigate the challenges caused by their own variability.

The following Sections 6.3.1 to 6.3.3 therefore discuss three possible measures for limiting and dealing with the variability of variable RES-E:

- Improved forecast accuracy of variable RES-E;
- Regional sharing of reserves and balancing services;
- Provision of ancillary services by RES-E.

6.3.1 Improved forecast accuracy of variable RES-E

The variability of wind and solar plants represents a key challenge for integrating large volumes of RES-E into the power system. Among others, forecast errors create substantial uncertainty for electricity spot markets and real time system operations. With an increasing penetration of variable RES-E, the power system needs additional volumes of operational reserves for dealing with unforeseen variations of production by RES-E plants in real time. Apart from fast acting balancing services for frequency containment and restoration, which are typically activated in a time scale of several seconds to minutes, these also include replacement reserves, which are needed to replace the faster acting services if a system imbalance persists. Irrespective of the design of commercial and operational arrangements (see Chapter 7.2 below), the corresponding services must be physically available when so required.

As mentioned above, operational reserves have traditionally been dimensioned to cope with generation outages and uncertainties on the demand side. But with an increasing penetration of RES-E, the necessary volume of operational reserves is increasingly driven by forecast errors of electricity production from variable RES-E. The (in-) accuracy of wind and solar forecasts thus has a direct impact on the need for operational reserves and hence the cost of system operation. In addition, it may also have an impact on the need for flexible capacity. Consequently, improved forecast accuracy may help to facilitate the integration of variable RES-E.

Experiences to date have shown that there is considerable scope for reducing the forecast errors of wind as well as solar power. Apart from improved day-ahead forecasts, which are more relevant for trading in the day-ahead and intra-day markets, significant improvements have also been achieved for the time scale of several hours ahead of real time, which is decisive for the dimensioning and holding of certain types of replacement reserves. It is beyond the scope of this study to further explore possible approaches for improving the accuracy of wind and solar forecasts and the improvements that may be achieved. But a recent study from Germany[58] found that it might be possible to reduce wind forecast errors by up to 45 % by 2020, which represents a significant improvement compared to today. This view is also supported by other studies and research papers, which suggest that substantial further improvements are possible, for instance by combining different forecast models.

We have refrained from carrying out additional simulations. But the results reported in the following Section indicate that reduced forecast errors of wind and solar power may allow reducing the need for back-up capacity as well as operating costs. The corresponding savings will likely remain limited in comparison with overall system costs, but can still be expected to be significant. At the same time, improvement RES-E forecasts can be considered as a relatively low-cost measure since they do not require major investments or large operating costs.

6.3.2 Regional sharing of operational reserves and exchange of balancing services

Down to the present day, balancing services and operational reserves are normally procured by each TSO individually, i.e. separately for each control area and/or each country. At the same time, a major share of these services is used to a limited extent only but mainly has the characteristic of an 'insurance' service that is required for dealing with critical situations. Subject to the availability of sufficient interconnector capacity, increasing regional cooperation in this area hence represents a potentially promising instrument. Apart from the exchange of available balancing services in real time, this may potentially also involve the regional sharing of operational reserves between different control areas.

The benefits of regional coordination and cooperation are acknowledged by the Electricity Target Model and are also reflected in the provisions of the Framework Guidelines on Electricity Balancing as well as the draft Network Code on Electricity Balancing. Indeed, the latter documents explicitly call for the cross-border exchange of balancing energy and ultimately aim at a common procurement of operational reserves. In addition, some progress has already been made in recent years. For instance in Scandinavia, the Nordic TSOs have already been using a common balancing mechanism for the procurement and activation of balancing energy for several years. Other examples are the so-called (International) Grid Control Cooperation (IGCC) among the four German TSOs, which has recently been extended to Belgium, the Czech Republic, Denmark, the Netherlands, Slovakia and Switzerland, as well as similar scheme between Austria and Slovenia. Although most of these examples have so far been limited to exchange of

58 See for instance dena. dena Grid Study II – Integration of Renewable Energy Sources in the German Power Supply System from 2015 – 2020 with an Outlook to 2025. November 2010

balancing services in real time, the German example shows that a regional sharing of operational reserves may also allow reducing the total amount of reserves.

To illustrate the potential gains of this measure, we have simulated an additional sensitivity where operational reserves are no longer provided on a national basis but on a regional basis. In practice, we have assumed that the three types of ancillary services considered by the generation and market model are fully shared within a limited number (7) of defined regions, such as the Nordic countries, UK & Ireland, the Iberian Peninsula, Central Europe, Central Eastern Europe or South Eastern Europe.

Based on the results of the market model, regional sharing of operational reserves allows for a limited reduction of investments into additional back up capacity. More specifically, the necessary volume of back up capacity can be reduced by approx. 5%, whereas we do not observe any tangible impact on incremental transmission capacity. This indicates that a certain share of the need for back up capacity is at least partially driven by the need for operational flexibility, and not only the requirement of 'firming up' production by RES-E.

In addition, regional sharing of operational reserves also allows for a better utilisation of existing plants, in particular where conventional plants have to be started up for the purpose of providing spinning reserves. Depending on the frequency of corresponding instances and the volume of generation capacity activated for this purpose, this measure may thus allow for additional savings. The simulations in this study as well as the findings of others[59] indicate that these savings are likely to remain limited in relation to the overall costs of electricity supply.

6.3.3 Provision of ancillary services by RES-E plants

Today, ancillary services are mainly supplied by conventional generators, i.e. thermal generators and hydropower, as well as (pump) storage. As explained in Sections 6.2.3 and 6.2.4, novel types of storage technologies as well as demand response represent other possible sources of ancillary services, which may become increasingly relevant in the future. In addition, RES-E plants may also contribute to the provision of ancillary services. This is straightforward for technologies that are essentially based on the combustion of fuels derived from renewables energies, such as biomass and biogas. Nevertheless, even RES-E plants based on variable resources, such as wind and solar power, are principally capable of providing certain ancillary services and may represent an economic choice in certain areas.

One relevant application is the provision of reactive power and voltage control from both wind and solar plants. This aspect is discussed in more detail in the context of active distribution grids or smart grids in Section 6.5.2 below. In addition, wind and solar power may principally also contribute to the provision of operational reserves and frequency response. Technically, this mainly requires the installation of necessary control and communication facilities, in order to control and adjust the output in real time. For practical purposes, however, one furthermore has to differentiate between the provision of positive and negative reserves.

Positive reserves serve to increase production at the instruction of the system operator. In the context of variable RES-E, this service requires a (partial) reduction of the output of one or more given facilities. This may require sophisticated measures for measurement and control, in order to limit mechanical stress and since the available output of a given facility is not perfectly known in advance, especially once it has been partially or fully curtailed. Nevertheless, these issues can principally be overcome, in particular when using a portfolio of several similar installations in the same area where one or more units in 'normal operation' can be used as a reference for others that provide ancillary services.

59 See for instance ECF. Power Perspectives 2030, On the road to a decarbonised power sector. Brussels. 2011

In practice, the economic and environmental consequences of a partial curtailment of RES-E can thus be expected to represent the main barrier. This measure reduces the active power supplied by these plants, which has to be compensated by other generating units. Given that the available output of for instance hydropower or biomass plants is limited, the provision of positive reserves from variable RES-E thus generally requires additional production by conventional generators based on fossil fuels. The combustion of additional fuels naturally increases CO_2 emissions. But it will also increase operating costs, due to the additional fuel consumption and hence the much higher variable costs of conventional generation. Except in situations with an excess of electricity, the provision of positive reserves from variable RES-E is thus unlikely to represent an economic choice.

The situation is different in case of negative reserves, i.e. an instructed reduction of current production. In principle, the activation of negative reserves from variable RES-E does again imply that available energy from wind or solar power remains unused. However, assuming that generators will offer balancing energy based on their variable costs, it seems reasonable to assume that the production of variable RES-E will only be reduced once other sources (i.e. from conventional generation, hydropower / storage, or demand response) have been used. In these cases, however, a temporary curtailment of RES-E seems more beneficial than the alternative of an increased planned production level of other (conventional) generators, only for the purpose of being able to reduce their output when so required.

In line with these considerations, we have only modelled the provision of positive reserves in our simulations and have furthermore assumed that these services are exclusively provided by conventional generators, storage and demand response (see Section 5.2.2).

6.4 Transmission

6.4.1 Use of alternative transmission technologies

The infrastructure requirements already mentioned include large investment in transmission grids in order to integrate the large share of renewable energy sources in the upcoming years. These additional costs can be minimized by applying and selecting some robust technical solutions for transmission networks.

The standard transmission infrastructures considered in the study is characterized by overhead AC and DC lines, submarine DC cables and the corresponding substations and AC/DC converter stations, mainly used for offshore interconnections between those offshore generation regions and the continental network.

The transmission expansion derived from the model reflects the use of these current standard technologies, but in fact, there are several aspects that can be also analysed, not only to reduce the costs of the investments in additional capacity, but also to increase the Grid Transfer Capability of the existing grid by using alternative solutions.

Based on this, each alternative solution has its own advantages and disadvantages, depending on certain regional transmission network specificities. Some alternative solutions are as follows:

- Undergrounding of overhead lines;
- High temperature conductors;
- Line monitoring.

One solution identified in some studies is related with the undergrounding of overhead lines. This measure is comprehensively challenging and in some cases not technically feasible. Considering that the cost of an underground cable is 5 to 10 times higher than standard overhead lines, planning this infrastructure solution can be demanding and in some cases cause delays to some transmission projects. A delayed transmission system, as shown before, will require additional investments in back up capacity, in a system with high penetration of renewable sources.

Another disadvantage is related with the proximity to the ground of electromagnetic fields driven by Extra High Voltage (220 kV to 400 kV) underground AC lines, which can be subject to public acceptance, causing even more delays to transmission expansion projects. In case of any fault in a line or for maintenance reasons, the operation and maintenance costs associated with the undergrounding would rise, considering that the access to a certain point of a line becomes more difficult and the repair would cause a decrease of system availability and reliability.

A solution to optimize transmission capacity of a given power line is the use of high temperature conductors. By upgrading the existing overhead lines with these new high temperature conductors, the total requirements for additional Grid Transfer Capability would be reduced, even considering some minor changes related with the existing infrastructure. In addition, new overhead lines would have higher Grid Transfer Capability values, allowing the integration of energy provided by solar PV plants and by onshore and offshore wind power plants.

Nevertheless, this solution can be identified with one downside, since high temperature conductors will conduct to more grid losses, and this will mean that in order to have the same amount of available transmission capacity, more capacity has to be installed.

Grid management and operation is also important to ensure system security and reliability. In order to ensuring a reliable system with large share of renewable energy sources, system monitoring can have a main role to maintain transmission networks available. Overhead Line Monitoring can be used to optimize grid operation and its main features include monitoring the transmission capacity of overhead power lines taking into account real-time meteorological data. Its effects are not yet fully tested, although the development of this technology in the future can maximize the utilization of the existing capacity and limit the investment in additional transmission capacity.

This alternative will allow real-time monitoring of the available transmission capacity, considering the effects of temperature in the transmission capacity. The maximum capacity of an overhead line is determined by the maximum temperature that energized conductors can support and the minimum distance to the ground. Considering these monitoring improvements, the online meteorological data provided of weather conditions of a specific place, such as temperatures and wind speed, will allow the maximization of transmission capacity usage of existing lines. This benefit can be relevant to improve the Grid Transfer Capability of existing power lines and to evaluate additional infrastructure requirements.

The information about weather conditions will be useful for real-time operation to determine the available transmission capacity in high demand periods, where the conductor’s temperatures can easy hit its maximum allowed temperature. Besides, taking into account the wind speed in a specific point is also very useful for conductors cooling and, thus, more transmission capacity will be available.

6.4.2 Improved network monitoring and control

The integration of large volumes of RES-E into transmission and distribution grids will require constant network monitoring and control, in order to maintain the voltage levels within infrastructure limits and reliable, as well as other technical aspects. Thus, monitoring and control systems have to be enhanced and this will also require significant additional investments by TSOs, to provide the expected flexibility and security of transmission systems operation.

Some technologies used nowadays have already provided system control and they proved to be reliable and efficient in this respect. The development of existing technologies and the deployment of new techniques, will lead to an even more improved control system, needed to integrate renewable energy. Although a more detailed description of technical characteristics is out of scope of the present report, this Section provides an overview of possible solutions. Some solutions, which can be technologically improved in the future, include the following:

- Phase Shifting Transformers;
- Flexible Alternating Current Transmission Systems;
- Wide Area Monitoring Systems.

The first solution, Phase Shifting Transformers (PST), is used to control active power flows by regulating the phase. This technology already used by some TSOs who are able to increase the transmission capacity of other power lines of a specific grid with available capacity, whenever a line is not able to use more capacity.

Flexible Alternating Current Transmission Systems (FACTS) are another possible solution, although their efficiency and reliability is not yet fully tested and proven. In addition to this, their high costs are sometimes one of the reasons why there are not so many investments in this technology. Yet, FACTS are devices with the ability to increase power transfer capability more dynamically than PSTs, combining reactive power compensation as well as voltage control. With further improvement of power electronics and control equipment, FACT’s may become a viable solution for network monitoring and control in the future.

For monitoring purposes, Wide Area Monitoring Systems (WAMS) allow a continuous monitoring of transmission systems of a large area, detecting system instabilities which may cause an impact on the transmission system of a specific region and increasing system security and reliability. Yet, this information system faces several difficulties regarding its integration and harmonization among different control systems, which may delay the recognition of its potential and its benefits to the overall system.

6.4.3 Construction of overlay grids

The basic transmission modelling is based on the use of traditional technologies and design standards, i.e. the extension of the existing AC grid. As an alternative, it is often proposed to build a number of 'electricity highways' across Europe, with a mix of DC lines for long-distance transport and AC grid expansion with a more local character. In a similar context, it is often suggested to also create an integrated offshore grid

HVDC solutions are more expensive than traditional AC lines for shorter distances. Thus, a distance above 50 km (for submarine cables) and a distance above 600 km (for overhead DC power lines) are required to have an economically feasible project. This technical solution has already proven its efficiency and availability, and a reduction in the upcoming years of the overall costs, including the converter costs, can result in a very competitive alternative to traditional AC connections.

In the present study, we have analysed several potential long-distance corridors that may be used to integrate RES-E into the European network. The following method was used to identify a possible overlay grid:

- Identification of a set of possible long-distance HVDC corridors;
- Definition of a set of offshore connections in the North Sea.

The design of this overlay grid was based on Scenario 1a, in which significant additional investments in transmission were required.

Figure 130 shows that this sensitivity resulted in a limited reduction in transmission expansion. Nevertheless, as shown in Figure 131, the sensitivity resulted in the construction of several long-distance corridors. These corridors basically reflect the structure of the original grid, i.e. from Northern Scandinavia through North-western Germany France to Spain, with two radial connections from France via Scotland to Norway, and from Sweden to Central Eastern Europe. The main corridors identified in Figure 131 represent symbolically the interconnections between different regional nodes considered in this study.

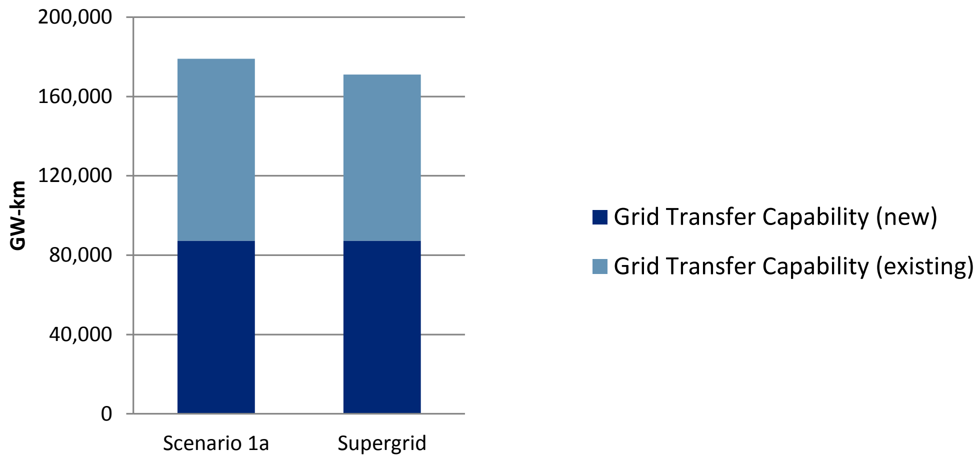


Figure 130   Impact of European overlay grid on cumulative Grid Transfer Capability

No significant changes were identified in terms of back up capacity requirements, as well as regarding the level of curtailment of renewable energy sources, such as wind and solar PV. Similarly, most market indicators showed marginal changes only.

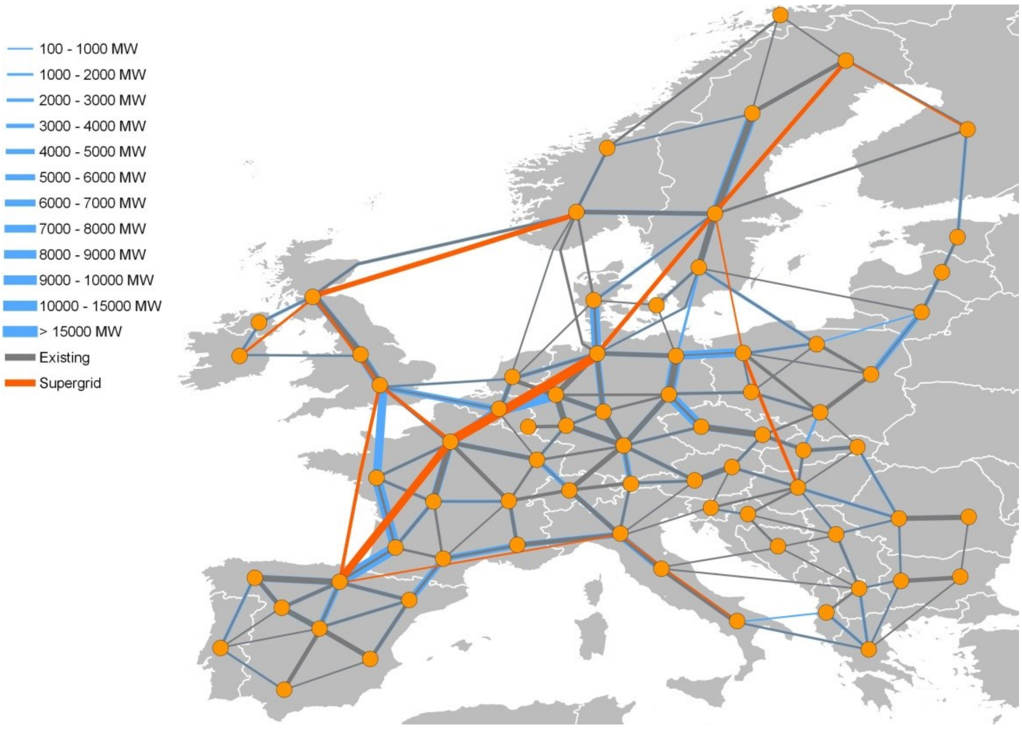


Figure 131 Impact of overlay grid on European grid topology (2030)

6.5 Distribution

6.5.1 Reverse operation of distribution circuits

Distribution networks were designed for a downwards distribution of electrical energy, exclusively expecting top down power flows. If an increasing number of DG is installed in distribution grids, inverse power flows may occur during periods of low electricity demand and high infeed. For a large share of the European distribution grids the possibility of backfeed of energy was not taken into account at the planning stage of distribution grids. With respect to metering devices and control systems the inverse operation of distribution grids requires replacement and upgrade of the distribution networks safety and metering equipment. Safety relays of substations and meters at customer transfer points require detection and metering of bidirectional electricity flows. This results in necessary replacements of unidirectional meters by four quadrant meters and bidirectional safety relays installed in substations.

The upgrades described above represent the basic measures for the integration of Decentralised RES-E generation. Technically and cost wise this upgrades are expected to cause comparably limited efforts. While regions with high shares of DG generation were already provided with upgraded network equipment, there are still many distribution grids in Europe which are lacking these basic adjustments.

6.5.2 Active distribution grids / Smart grids

Traditionally distribution grids were designed for top down energy flows. This included control and monitoring devices for substations and most medium voltage lines, while below the MV level no active network components were installed. Without any DG infeed a passive management of the lower levels of the distribution grid represents the cost-efficient and sufficiently safe way of network operation.

The installation of active components for switching, measuring, monitoring and communication in distribution networks, allows an active control of the equipment. This can be summarised under the term “smart technologies”. Installing smart technologies represents an option for partial or complete compensation of conventional reinforcement of distribution grids, allowing the integration of larger scales of DG capacities. In general the following options represent the main components of a smarter distribution grid:

- Area voltage control;
- In-line voltage control;
- Voltage regulated distribution transformers (Automatic on-load tap changer);
- Adjustment of the power factor of solar-PV inverters.

Area voltage control refers to the control of the secondary voltage of transformers which are installed in the MV networks or the HV/MV substations, depending on the measurements of sensors in subordinate voltage levels. This relatively new concept intends to avoid violations of the voltage limits in LV networks levels by adjusting the voltage on superordinate network levels by considering the information input of additional sensors and communication infrastructure at the crucial points of the distribution grid. For distribution grids with a homogenous consumption and feed-in profile across the feeders this technology represents a promising future option for a cost-efficient voltage control and a partial compensation of conventional grid reinforcement.

Another option for regulating the voltage of distribution grids, is the installation of controllable capacitors and inductors. These compensation elements allow the regulation of reactive power by adjusting the power factor. If the voltage regulation need is driven by solar PV generation, *in-line voltage regulation* represents an alternative to active control of the power factor of inverters.

The installation of *automatic on-load tap changers in distribution transformers* allows the decoupling of the secondary voltage of the transformer from the primary voltage. This voltage decoupling allows using a higher share of the voltage range for LV networks. As the transformation ratio can be changed within a second during normal operation, the voltage level can be regulated using the discrete steps of the tap changer. This technological innovation is promising for distribution grids which have to face an increasing penetration of solar PV feed-in. It is important to note that thermal limits of cables and the transformer apply also for voltage regulated transformers and that in case of a very uneven distribution of load and solar PV across the LV-feeders connected to the transformer, the benefit of the common voltage regulation of the transformer for all feeders is limited. The technology is ready for mass production and the roll-out is tested in several projects. In order to determine the cost reduction potential on distribution reinforcement, a sensitivity assuming a large scale integration of transformers including an automatic on-load tap changer was analysed. For the year 2030, assuming additional costs per on-load tap changer transformer of € 17,000 compared to conventional transformers, the cost for conventional and smart grid reinforcement are shown in Figure 132. A cost decrease of some € 25bn can be expected in case of the installation of voltage regulated distribution transformers in distribution grids facing voltage driven problems at lower voltage levels. The cost reduction of around 10% confirms the mentioned fact that the smart transformers are only addressing voltage problems. In the year 2030 the expected remaining costs level of the on-load tap changer transformers accounts for a significant share of around 15% of the total reinforcement cost.

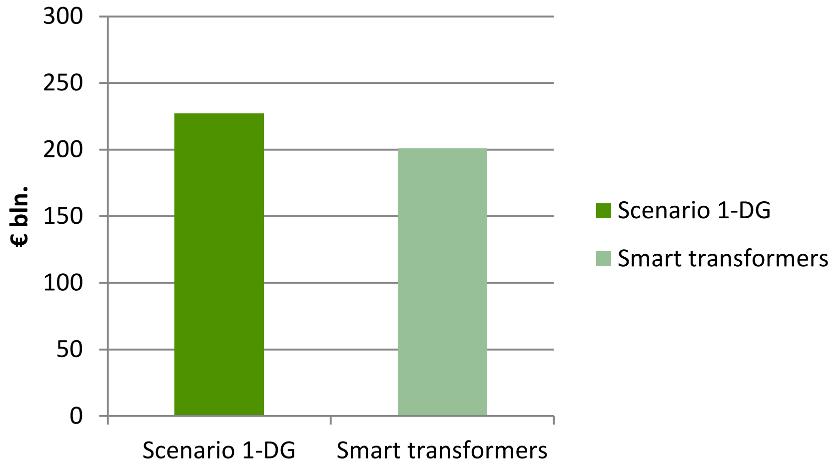


Figure 132 Comparison of conventional and smart grid reinforcement, in 2030 (EU-28, in EUR bn)

Another option of enforcing the distributions grid capability of integrating distributed RES-E, is the *adjustment of the power factor of solar PV* inverters. The voltage driven reinforcement needs, which were described above can be eased by adjusting the power factor of solar PV inverters. The voltage increase related to high infeed of DG-RES and backflows can be countered by the provision of reactive power of inverters. Inverter technology is already providing reactive power compatible products. The power factor of the inverter can be set either to fixed value or to a variable value allowing active control of the reactive power provision of inverters. The application of a power factor of less than one increases the output power due to the increasing apparent power. This results in the necessity to install inverters with higher rated power. In this case plant operators have to finance the oversized inverter, making the solar plant more costly.

In Germany, distribution system operators had to face the problem of voltage increase in ne distribution networks. In areas with high-penetration levels of small scale solar PV, the coincidence of high generation and low electricity demand causes a significant voltage rise in grid. As it was shown that the adjustment of the power factor increases the distribution grids capability for handling high levels of solar PV infeed without causing violations of the voltage limits, an amendment of the guidelines on connection of solar PV was decided. According to the guidelines on connection, solar PV inverters are required to provide a power factor of up to 0.9. An inductive power factor of 0.95 and 0.9 is applied for most of the solar PV plants. By implementation of these guidelines, mainly by the application of under-exited generation mode of PV inverters a reduction of the voltage increase is intended. In order to assess the potential cost reductions of distribution reinforcement sensitivity calculations, applying an inductive power factor of 0.95 and 0.9 were performed. The analysis of the results shows that a power factor of 0.95 reduces the overall cost in case of Germany by a few per cent. As expected the highest cost reductions can be observed for the voltage driven cost in LV networks. Conversely, an increase of the cost driven by thermal limits can be stated. This development is mainly related to the local provision of reactive power which is not locally compensated during hours of low demand, leading to an increasing apparent power backflow causing additional load for cables and transformers. In case of a power factor of 0.9 for all installations the benefit of voltage costs reductions is compensated by the additional cost for grid reinforcement due to the high levels of apparent power.

This example shows that an adjustment of the inverters power factor is able to reduce the voltage driven costs to a certain extent. It increases the ability of networks to integrate DG but as thermal constraints even represent the more limiting factor in case of increasing apparent power, the conventional reinforcement needs still apply.

6.5.3 Restricted operation and curtailment of decentralised RES-E

Apart from the reinforcement of the grid and advanced control measures of network components, limiting the energy output of decentralised RES-E represents an option for avoiding operational problems. Especially for solar PV, the number of hours of generation close to peak capacity is relatively low within a year. If the network is expected to be capable to absorb these rarely occurring peaks, high effort must be made to enforce the grid for a limited number of energy. Avoiding the maximum generation can be done by ad-hoc curtailment, or alternatively by introduction output limit for each plant. Cutting off all generation above a fixed value allows shaving the peaks. This curtailment of RES-E causes no additional costs, apart from the value of the lost energy. This trade off-between peak reduction and lost energy must be kept in mind when considering the cost related to curtailment. The actively restricted operation of DG power plants represents another option for avoiding maximal network reinforcement. In this case an active control of the DG-RES plants and the network status is required. But the more elaborate option of restricted operation of DG plants goes with an expected reduction of the energy volumes being curtailed.

In order to assess the cost effect for different curtailment standards, the cost reduction for several restriction levels were analysed. The cases listed in Table 25 were taken into account for the curtailment analysis. For the generation profiles the limitation of the maximum output was applied using the curtailment levels listed in table. Furthermore the energy which is lost due to the curtailment of DG-RES is shown for the different cases.

Table 25 Consideration of different levels of constrained output of DG-RES

case	Cap for solar PV LV	Cap for solar PV MV	Cap for Wind All network levels
I	80%	80%	-
II	70%	80%	-
III	60%	80%	-
IV	80%	80%	80%

Figure 133 shows the impact of different levels of curtailment on the cost of electricity of supply. Apart from the cost of distribution reinforcements, the values shown in Figure 133 also consider the value of energy which is lost due to the curtailment of RES-E. The value of lost energy has been determined by multiplying the volumes of energy curtailed with hourly wholesale market prices in each transmission zone. It thus corresponds to the marginal production costs of other generators that are called to make up for the shortfall in production.

Figure 133 reveals that the overall savings from restricting the output of DG-RES remain limited, or that this measure may even lead to increasing cost. A maximum of approx. € 1bn in cumulative annualised distribution reinforcements can be saved if production by LV-connected solar PV is capped at 60% of installed capacity (case III). In this case, however, the value of the lost energy corresponds to around €

0.6bn, which means that the effective cost reduction decreases to some € 400 million, or about 2% of the original cost. Whilst restricting the output of solar PV thus helps to avoid network expansion, its overall impact remains limited at least in scenario 1-DG.

The alternative restriction of both solar PV and wind to 80% of installed capacity (case IV) even leads to increasing costs. In this case, the benefits of reduced distribution expansion are more than offset by a significantly higher value of lost energy. In this context, it is worth noting that high levels of production by solar PV are highly correlated with low electricity price levels. As a consequence, the value of lost energy is relatively low for solar PV. Conversely, the correlation between higher production by wind power and low electricity prices is much weaker in this scenario.

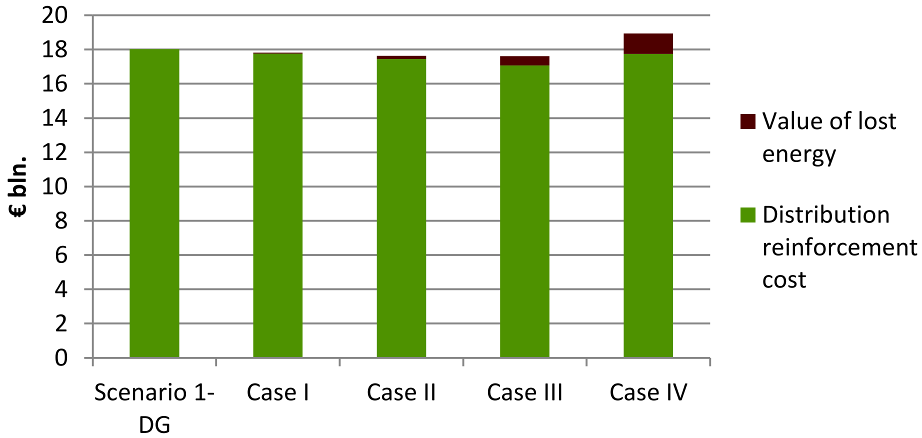


Figure 133 Impact of constrained operation of DG-RES on distribution reinforcements and curtailment of RES-E

7 ANALYSIS OF POSSIBLE OPTIONS AND REQUIREMENTS IN REGULATION AND MARKET DESIGN

7.1 Overview

The aim of this report, broadly, is to identify efficient means of integrating renewables into the European power system accounting for the impacts of different levels of RES-E on the wider network infrastructure, and to consider ways to ensure that the expansion of RES-E output is done in a way that is economically efficient, taking into account market and non-market factors. The preceding chapters approach this question through the application of two optimisation models that take decisions regarding investment in generation, transmission and distribution capacity to minimise power sector costs under a range of assumptions regarding the location, scale, and type of renewable generation capacity deployed in the European power system over the period to 2030.

7.1.1 Defining efficient outcomes

It is important first to be clear about the meaning of the term "efficient" in this context. We use the term to refer to *economic* efficiency, in the sense that the outcome maximises (social) welfare, which occurs when the marginal benefit associated with a sector's incremental output equals the marginal cost of achieving its incremental output.[60]

Even this definition of efficiency can be applied in different ways, however. Often, because some benefits can be difficult to quantify, economic efficiency is set aside as a criterion and cost-effectiveness is used instead.[61] Cost-effectiveness can be ensured by trying to minimise the cost of achieving a specific outcome or target. So, for example, a renewable energy target may be set at some level, on the basis that it delivers some (unquantified) benefits at a level that is judged to be commensurate with its costs.[62] The question of whether the target is set at an economically optimal level that maximises social welfare is set aside. Instead, that question is replaced by the often easier question of how to achieve the given target at the lowest cost. If one assumes that the target is set at the "right" level (that is, the level that maximises total welfare), then minimising the cost of meeting the target will also yield an efficient outcome.

The preceding chapters describe modelling work that aims to minimise the costs of providing electricity under a wide range of possible scenarios on future renewables penetration that are consistent with current and potential future targets. They therefore address the question of how to meet assumed targets at least cost. However, because we do not know whether the target levels have been set at the optimal levels to begin with, it is difficult to determine whether this will yield the efficient outcome.[63]

Moreover, modelling on the scale required by this assignment necessarily involves numerous assumptions and simplifications of the real EU power system. The nature of the required assumptions is such that many of them may turn out to be suboptimal to a greater or lesser extent. The modelling

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60 " Output" here may include not only electricity, but the wider set of outputs that the renewable electricity sector is relied upon to provide, including energy security, the social stability provided by a competitive industrial base, carbon emissions reductions, air quality improvements, etc.

61 In the case of renewables, we can see this by considering the wider objectives of EU energy and climate policy: competitiveness sustainability and security of supply. All three of the objectives refer to outcomes whose economic value cannot be determined via reference to market prices.

62 This assessment may be done taking into account wider political considerations and interests, for example.

63 In principle, one could assess the efficient level of renewables penetration by comparing the results produced from a range of scenarios with different assumed levels of renewables penetration. However, this is unlikely to produce conclusive results, as some of the benefits associated with renewable energy are directly quantified in the modelling – for example, impacts on CO_2 emissions – and their value can be monetised. But many benefits are not quantified, and cannot be valued in within the modelling framework applied for this study.

results should therefore not be seen as identifying the efficient pattern of investment. Instead they are illustrative how efficient investment decisions may change in response to certain policy and market assumptions.

7.1.2 Defining policies to accommodate efficiently a given mix of renewables

From economic theory, the aim of promoting economically efficient outcomes is best achieved through well-functioning, competitive markets, in which participants are exposed to the marginal costs they impose on the system, and receive the marginal benefit they provide to the system through revenues or cost savings. Moreover, if the assumption of perfect competition holds, then we would expect the modelled outcomes to be consistent with those produced by a perfectly competitive market.

In reality, however, European energy markets do not conform to the notional ideal of perfect competition. Market failures, such as the impact of externalities or natural monopoly, mean the modelled least-cost patterns of investment might not take place. Distortions created by regulatory interventions can also result in inefficiencies, and there may exist some other real-life costs or constraints of which the models have not taken account.

Given the market imperfections that exist in reality, some observers might conclude that interventions by policymakers are necessary to mandate certain outcomes or levels of investment. However, given the challenges described above associated with using modelling to identify the efficient means of integrating renewables into the European power system, it is neither feasible nor desirable for policymakers to *prescribe* the optimal types, locations, and levels of investment required to accommodate renewables efficiently. Instead, efficient integration of renewables can be best achieved by implementing power market designs, network charging arrangements and renewable support schemes that promote effective competition and economically efficient outcomes. In this context, modelling provides a useful tool for understanding what outcomes may be feasible and therefore what policies may be more or less effective.

Drawing on examples from the modelling results above, this chapter therefore identifies and describes reforms that are either essential or beneficial to encouraging efficient RES-E integration, identifying (where appropriate) any preconditions, and taking account of the EU's wider energy objectives. We begin by discussing the design of the wholesale power market, including both how RES-E sources affect it and how they may be affected by it. The next sub-Section 7.3 considers the regulation of transmission and distribution networks – in particular, how investments in new capacity are incentivised and how network charges can be used to promote efficient outcomes. Finally, Section 7.4 considers how the design of renewable energy support policies affects the efficiency of integration of renewables. In all three of these areas – wholesale market design, network regulation, and RES-E support – the issues are not independent of each other, and there are significant overlaps between the policy design questions.

7.1.3 Other policy considerations

In the sections that follow, where the specific application of the definition of economic efficiency is relevant to the interpretation of the modelling results or the policy recommendations, we note this. For example, minimising the cost of achieving a pre-determined outcome is consistent with the EU's 2020 approach to RES-E policy, which sets a 20 percent target for RES-E overall. In the context of the climate and energy strategy for 2030, however, there has not yet been any decision about whether to set (or at what level to set) a RES-E target, so it may be more relevant to think in terms of equating marginal costs and marginal benefits. This would involve trying to define, measure, and value the benefits associated with different levels of security, sustainability, and "competitiveness".

Beyond the focus on economic efficiency, policy-makers are also often concerned with distributional effects, or "equity". Outcomes that are economically efficient may not always distribute the net welfare benefits in ways that policy-makers deem fair. Where benefits and costs accrue in ways they judge to be unfair, policy-makers may actually prefer policies with certain distributional outcomes even if in the aggregate they are less efficient. In the context of the current study, impacts on end-user prices may be of particular concern – especially given the significance of economic competitiveness. In addition, if RES-E targets are taken as given (and necessary), but there are concerns that certain policy and regulatory options – even if efficient – make it more difficult for RES-E targets to be met, policy-makers may decide that these considerations take precedence over efficiency. Where such decisions are made, they should be made openly and transparently.

We turn now to our discussion of the three key areas of policy that are likely to affect the efficiency of investment and operation of RES-E, beginning with the design of the wholesale power market.

7.2 Design of Wholesale Market

In this Section, we discuss a range of policy measures that may help improve the efficiency of outcomes in the wholesale electricity market, while meeting the challenges created by increasing renewables penetration that the modelling results shown in preceding chapters illustrate.

7.2.1 Efficient pricing in wholesale markets

Competitive electricity markets send signals to market participants regarding the marginal benefit they create, or marginal cost they impose, through market prices. In competitive energy-only markets, the price to emerge in any given trading period (e.g. an interval between 15 minutes and one hour) equates to the system marginal cost that defines the underlying value of energy during that trading period. In conditions where the available supply exceeds demand, the system marginal cost will be set by the variable cost of the marginal source. However, in periods of scarcity, which may occur either because of unusually high demand (e.g. in peak demand conditions) or due to sudden interruptions to supply (e.g. a rapid reduction in wind output) demand must be rationed to reflect the available supply and prices will rise to a level reflecting consumers' short-run valuation of energy, usually referred to as the Value of Lost Load (VOLL), rather than a generators' short-run cost of electricity production. In such periods of shortage, any parties selling energy on the wholesale market will capture "scarcity rents".

A well-established theoretical literature shows that this pricing rule, including the payment of rents in periods of scarcity, rewards efficient, competitive behaviour by investors in generation.[64] Ensuring that prices reflect marginal cost, as they do in this theoretical representation of a competitive market, is therefore the best way to ensure efficient market outcomes, and hence the efficient integration of renewable power generation.

For example, a key trend illustrated by the modelling is that higher levels of renewables penetration tend to increase the need for investment in peaking (i.e. "backup") capacity relative to "baseload" and "mid-merit" technologies such as gas-fired CCGT or coal-fired generation. Figure 57 shows that roughly the same amount of new capacity is added across Scenarios 1, 2 and 3, but a greater proportion of capacity is back up generation in Scenario 1, which has the highest RES-E penetration.

64 See, for example, Hunt and Maloney (1975), IAEA (1984) and Masters (2004).

To incentivise market participants to provide an efficient mix of generation when taking investment decisions,[65] wholesale energy prices must send efficient signals to investors regarding the value of energy across all hours of the year. In theory, therefore, the increasing need for peaking plant relative to baseload" and "mid-merit" technologies should be reflected in higher spreads between peak and off-peak wholesale electricity prices, which should in turn incentivise efficient generation investment patterns. To some extent, this trend can be seen in the modelling. For instance, Figure 104 illustrates that by 2030, peak/off-peak spreads are highest in Scenario 1 (with high RES-E penetration) and lowest in Scenario 3 (with low RES-E penetration).

7.2.2 Problems with energy-only markets and potential solutions

7.2.2.1 Constraints on peak energy prices

In reality, energy-only markets may not function as this theoretical paradigm would suggest. In particular, actual or perceived caps on market prices may undermine investors' expectation that prices will spike to the Value of Lost Load (VOLL) in periods of scarcity. As a result, those parties supplying energy in peak periods may not capture the marginal benefit of their investment. This "missing money" problem created by such caps on energy prices undermines incentives for efficient investment in peaking plants.

Where prices are capped below VOLL, investors in the efficient portfolio of new generation capacity recover lower revenues through market prices than the levels they require to recover their investment and ongoing fixed O&M costs.

For illustration, Figure 134 shows the effect on conventional generators' gross margins from capping energy prices at €10,000/MWh. In our modelling, we assume a VOLL of €50,000/MWh, which is the level to which prices should spike in an efficient energy only market in hours when load shedding is required. To illustrate the effects of constrained peak prices, Figure 134 shows the gross margins, which conventional generators would earn in the years 2025 and 2030 with and without a price cap of €10,000/MWh, using Scenario 1 as an example. As the figure shows, capping energy prices may have a substantial impact as generators see their margins fall as a result of this price cap.

65 As well as incentivising the efficient level of investment in new capacity, efficient wholesale price signals, which include the value of any scarcity rents, are equally important for providing efficient signals to existing generators regarding the value of their capacity, which can (and, in an efficient system, should) affect their decisions over when to retire capacity.

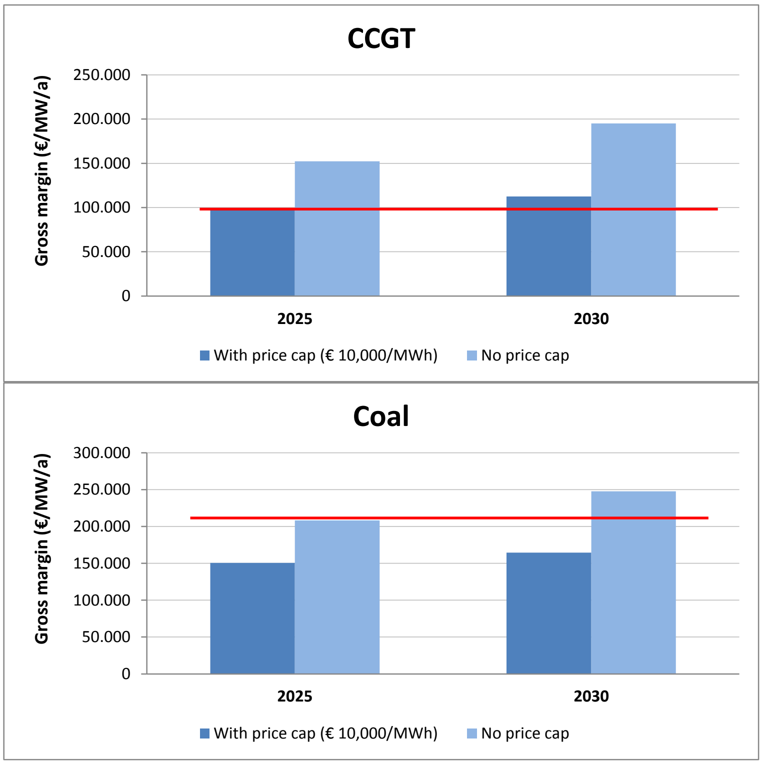

Figure 134 Gross margins from wholesale market revenues of CCGTs and coal plants, with and without a price cap of €10,000/MWh (Scenario 1)

One step to correcting this "missing money" problem may be to remove any administered systems that cause prices in peak periods systematically to depart from system marginal cost. In the British market, for example, balancing prices are calculated as a trailing average of the most expensive accepted offers, some of which may not recognise the existence of a shortage. Amending such rules to remove constraints on peak prices may help convey cost-reflective price signals to users and so promote efficient provision of generation and other technologies such as demand response and interconnection.

However, even changing these rules that systematically cause power prices to differ from system marginal cost would not fully compensate for the risk that regulatory authorities or governments may intervene by capping or reducing prices and profits within the sector during shortage conditions. Even the threat of such interventions weakens the incentive to invest, due to the risk perceived by investors that energy prices will not be allowed to rise when demand for energy exceeds available supply.

One way to resolve this problem is paying the "missing money" in the form of a payment for the capacity made available to the market. Essentially, capacity payment mechanisms (CPMs) offer a payment to providers of capacity to substitute for the scarcity rents they lose as a result of constraints on peak energy prices. They are for instance used widely in US power markets, but also in some European countries, including the Iberian electricity market, the all-Ireland market, Finland and Sweden. In addition, various countries, including France and the UK, are in the process of implementing such schemes.

It is also sometimes argued that by reducing generators' reliance for cost recovery on peak prices, it is possible to reduce the risk profile of investments in peaking capacity. For example, the Irish energy regulatory authorities state improving the stability of cash flows as compared to an energy only market as a stated objective of their CPM. It is possible, therefore, that the use of a CPM can reduce financing costs for the generation investments required to integrate renewables efficiently. In our experience, however, the market evidence on the financing costs faced by generators in markets with CPMs as compared to energy only markets is inconclusive, and depends very much on the detailed design of the CPM in question.

While CPMs provide, at least in theory, a means of improving the incentives to invest in an efficient level of generation capacity, in practice they differ widely in their design. If CPMs are designed inefficiently, or different CPMs operate in interconnected markets, they may create distortions. In particular, they may distort flows across interconnectors compared to the efficient levels. For example, the CPM operating in Ireland provides capacity payments to traders offering imports into the all-Ireland market, and imposes a capacity charge on exports to Great Britain. Because these charges are primarily determined ex ante and are additional to energy charges and payments, they cause the value of energy imported to the all-Ireland market to be higher than the true short-run marginal cost of energy in most hours. This effect may distort flows across the interconnectors compared to the efficient level.

A recent consultation from the European Commission makes the broader point that:[66]

> *"Incompatible or poorly designed capacity mechanisms risk distorting trading, production and investment decisions in the internal market… If capacity mechanisms become more common in the internal market the potentially distortionary effects will become greater. Member States who continue to rely on normal internal market rules are affected by the capacity mechanisms implemented in their neighbours, and might even fell [sic] compelled to intervene on their own markets to compensate for the effects of decisions in their neighbours."*

Therefore, while capacity mechanisms may have some role to play in improving the efficiency of outcomes in the EU power sector, they will be more effective and create fewer distortions if their design is harmonised. If this is not possible, however, it may be the loss of efficiency they create by distorting trade is greater than the improvements in efficiency they achieve by correcting the market failure associated with constraints on peak energy prices.

7.2.2.2 Market power

Market power is another potentially important source of market failure in European wholesale electricity markets, which, if exercised, would cause market prices to deviate from the marginal cost of supply and result in inefficiency. Identifying the means of promoting competition in wholesale electricity markets is beyond the scope of this report, but we simply note that policies which promote competition are likely to improve the efficiency of outcomes in wholesale electricity markets, including the efficiency of those investments required to integrate renewables into the EU power system efficiently.

For example, a number of EU-level policy initiatives, some of which have been implemented recently through the 3rd Package, are already aiming to promote effective competition within and between the electricity markets of EU Member States. These policies include, amongst others, compulsory separation of network and supply/generation businesses, the liberalisation of retail markets, the deregulation of end-user tariffs, measures to ensure non-discriminatory third party access to networks and the introduction of greater competition in the allocation of transmission capacity through the Target Model (see Section 7.2.7 below).

66 European Commission Consultation Paper on generation adequacy, capacity mechanisms and the internal market in electricity, 15 November 2012, pages 9-10.

7.2.2.3 Pricing of externalities

Another source of market failure in wholesale electricity markets is the presence of externalities, probably the most important of which is the emission of CO_2 from fossil fuel-fired power stations. In principle, the EU ETS prices in this externality, thus correcting this market failure. However, it is often suggested that the EU ETS undervalues the environmental damage caused by CO_2 emissions. For instance, the market prices of EU Emissions Allowances have been consistently below €10/tonne in recent years, whereas the modelling conducted for this assignment assumes a range between €15/tonne and €52/tonne, depending on the year and the scenario (see Table 21).

Accordingly, the EU policymakers are currently considering whether "structural reform" of the carbon market is necessary to address the perceived problem of excess supply of emission rights (including allowances and international carbon credits from the Kyoto Protocol) in the market.[67] As a short term measure, the Commission has proposed to change the timing of the auctioning of emission allowances ("EUAs") in Phase III, postponing the auctioning of 900 million EUAs planned for 2013, 2014 and 2015. However, "backloading" would not solve the problem of structural surplus of around 2 billion allowances over the Phase III period – it would merely postpone it. The Commission has therefore suggested six options for "structural" changes to tackle the long-term supply-demand imbalance:

- Retiring a number of allowances in Phase III;
- Increasing the EU's greenhouse gas emissions reduction target for 2020 from 20% to 30%;
- Early revision of the annual linear reduction factor;
- Extension of the scope of the EU ETS to other sectors;
- Limit access to international credits; and
- Discretionary price management mechanisms.

None of these measures have been implemented, and in the meantime, some individual Member States are taking, or at least considering, unilateral measures to internalise the externality associated with CO_2 emissions, such as the UK's Carbon Price Support scheme. Such unilateral measures will worsen the problem of oversupply of EUAs, and undermine the efficiency of power sector outcomes in Europe as a whole.

7.2.2.4 Distortions created by subsidy schemes

Another potential inefficiency in the wholesale electricity market is due to the structures of subsidy schemes paid to low carbon generators. Subsidy schemes for low carbon generation in some Member States effectively take generators outside of the market, paying them a fixed price for their output no matter what the wholesale electricity price. This type of scheme can create inefficiencies, because renewable generators do not face incentives to make themselves available at times when the system is particularly short of capacity, or to reduce their output at times of surplus. In some cases, stopping renewable generators, and running conventional generators instead, would reduce total variable costs.

The extra costs created by renewable generators unwillingness to reduce their output at times of excess supply can be seen from the modelling scenarios in which we assume renewable generators offer capacity into the market below their short-run variable costs, with offer prices between negative €50/MWh and negative €100/MWh. This practice increases the investments required in transmission

67 European Commission (2012) *Report from the Commission to the European Parliament and the Council – The state of the European carbon market in 2012* (http://ec.europa.eu/clima/policies/ets/reform/docs/com_2012_652_en.pdf)

infrastructure to accommodate the inefficiently high levels of running. This issue is discussed further below in Section 7.4.

7.2.3 Recognising the value of flexibility in energy and capacity markets

As described above, increasing the quantity of back up generation in high-RES-E scenarios may be justified on the basis that thermal plant will be required to run at lower load factors. This can make technologies such as OCGTs a lower cost generation option than technologies like CCGT, which are conventionally used for baseload or mid-merit operation. However, in high-RES-E systems, highly flexible generators (like OCGTs) can also help to integrate variable renewables efficiently. For instance, their fast ramp rates and short start-up times can help respond quickly to fast and/or unexpected changes in wind or solar production. Moreover, investments to improve the flexibility of the technologies that conventionally run baseload or mid-merit, e.g. by improving their efficiency when running at minimum stable load, may also facilitate renewables integration, as we discuss in Section 6.2.1.

In a well-functioning market, the differing ability of flexible and non-flexible generators to facilitate efficient renewables integration is conveyed to investors through their respective abilities to react to changes in market prices. For example, in markets with a high penetration of variable renewables, rapid changes in renewable generation may produce price troughs or spikes that are short-lived and/or hard to predict, thus preventing relatively inflexible generators from responding optimally to them by increasing or decreasing their output.

The measures set out above to improve the efficiency of wholesale market price signals can therefore help to reward flexibility. However, where capacity payments are used as a means of correcting the missing money created by constraints on peak energy prices, they should recognise the extent to which different technologies are capable of supplying energy during shortage conditions, and that more flexible generators are more likely to do so. In other words, CPMs should recognise that a (real or perceived) price cap creates different amounts of missing money for different technologies. Making the same payments to all technologies regardless of their flexibility may over remunerate inflexible units, and so increase the costs of renewables integration.

Some CPM designs are capable of rewarding flexibility. Consider a CPM designed around reliability contracts. In this case, a central body would sign contracts with providers of capacity, for the amount of capacity that it considers is required in an efficient power system. Each provider of capacity, possibly in return for a fee, enters into a one-way contract for difference (CFD) on the wholesale price. Suppose this contract strike price is set at €500/MWh. Now consider the remuneration provided to generators under this system in shortage conditions, which could be created by a general shortage of capacity, or a sudden reduction in output from variable renewables. If we assume the wholesale energy price spikes in these conditions to €2,000/MWh, providers of capacity would be liable for a payment of €1,500/MWh under their CFDs, but would recoup this cost by selling energy at €2,000/MWh. Hence, their overall margins in that hour are €500/MWh.

Suppose, however, that a provider of capacity were not able to generate because the period of scarcity occurred at short notice, and a lack of flexibility meant it could not start-up in time to exploit it. In this case, the generator would still be liable for a payment of €1,500/MWh under its CFD contract, but would not earn the compensating market revenues of €2000/MWh. Hence, an inflexible generator would make a loss of €1,500/MWh.

7.2.4 Efficient design of ancillary service markets

To some extent, however, the value of flexibility cannot be signalled through the energy market because fluctuations in output from variable sources occur within trading periods, which across Europe vary between 15 minutes and 1 hour. A possible change to market design to help recognise the value of flexibility would therefore be to shorten the trading interval used across EU markets, for example, to 5 minutes. This change to trading arrangements would extend the role of the energy market, which is similar to the approach adopted in PJM and some other US markets.

Whatever the length of the trading interval, there will still remain some need to recognise the value of generators' flexibility to adjust their output within the trading interval through ancillary service markets. Improving the efficiency of ancillary service markets can therefore also support the efficiency of price signals conveyed to market participants regarding the value of their assets in integrating renewables efficiently.

Competition in the supply of reserves is possible to some extent, and should be encouraged wherever possible as a means of improving efficiency in ancillary service markets, and sending clear price signals to providers regarding the value of their capacity. Pricing signals in ancillary service markets are especially important for ensuring an efficient allocation of capacity between the energy and reserve, as well as incentivising investment in capability for second-to-second and minute-to-minute balancing. However, at present, most European system operators procure reserves through tenders that take place periodically throughout the year, as well as through short-term balancing markets. Because tenders are typically performed for the provision of reserves over a period of days, weeks or months, the price signals conveyed to providers of ancillary services are relatively "blunt". It may therefore be possible to increase the efficiency with which reserves are traded by:

- Requiring system operators to procure reserves closer to real time through transparent, market-based mechanisms; and
- Aligning the duration of ancillary service contracts with the length of the trading interval.

These changes would convey more accurate information to market participants regarding marginal costs and hence the value of their capacity in the reserve market on a continuous basis, which in turn promotes efficient investment.[68] Creating common ancillary service market structures across neighbouring markets would also promote the efficient sharing of reserves, as discussed further below in Section 7.2.7.

7.2.5 Allocating the costs of ancillary service actions

In the energy market, prices signal the value of electricity to both suppliers and consumers during a particular trading period. Hence, if consumers use more power, they are exposed to the marginal cost of their actions, which should promote an efficient allocation of resources. In the market for ancillary services, however, the costs of provision are driven by a range of factors, including the level of demand, as well as the size of generators and mix of technologies that are despatched. To help promote efficient outcomes, it would therefore be desirable to signal to both generators and consumers the marginal ancillary service cost they impose on the system through their presence or actions. Such an approach could, for example, signal to providers of renewable generation technologies that variable technologies (like wind or solar) impose higher costs on the system than more predictable technologies (like biomass).

[68] In principle, market participants could also trade contracts for the provision of ancillary services ahead of real time to provide potential for hedging, and to provide longer term price signals to potential providers of ancillary services.

While it may promote efficiency to allocate the costs of ancillary services on a "causer pays" basis, in reality a mechanism that achieves this would be complex, so many market designs simply socialise ancillary service costs. The creation of a spot price for the provision of ancillary services, discussed above, may help allocate ancillary service costs over time, but allocating costs across users would require analysis and investigation to assess its feasibility.

7.2.6 Ensuring a level-playing field for alternative balancing technologies

As discussed in this report, it is widely suggested that alternative balancing technologies such as storage, DR and flexible generation can support the efficient integration of renewables into the European power system. To some extent, this hypothesis is supported by modelling results. Higher RES-E penetration tends to be associated with more curtailment of renewable generation to resolve transmission constraints, as illustrated in Figure 88. Some curtailment can be reduced through additional investment in storage capacity, although this increases power sector costs overall (see Figure 123 and Figure 125). DR can also reduce both RES-E curtailment and power sector costs (see Figure 126 and Figure 128), but the availability of DR (i.e. the willingness of consumers to reduce/shift their load) is highly uncertain, as are the costs of compensating them for doing so, which are not included in the costs calculated in the modelling.

Storage, DR and flexible generation can substitute for investments both in conventional generation and grids, and can also improve the efficiency of despatch and so reduce power system operating costs. The value of avoided generation investments and improving the efficiency of despatch can, in theory, be reflected through wholesale electricity prices that reflect marginal costs. In particular, the value of both technologies can be signalled through the ratio of peak to off-peak price spreads. Hence, the measures described above to promote efficient energy pricing should also promote the efficient deployment of these alternative balancing technologies.

While efficient market prices and network charges can promote efficient investment in these technologies in theory, in practice further measures may be required to ensure that these technologies, which are often developed on a relatively small scale, can compete on a level playing field with more conventional technologies like peaking generation. Most importantly, providers of small scale DR and storage will only receive signals regarding the value of electricity if they are subject to some form of real time pricing, which requires smart metering technology.

Some EU markets, including France, Spain, the UK, Finland and Sweden have begun the large-scale adoption of smart meters for small residential customers,[69] but realising the potential benefits of small scale DR may require a more wide-spread adoption of smart metering technologies across all Member States. However, what is not clear from the modelling conducted in this study is whether the savings that DR provides justifies the cost of providing smart meters. Further study would be required to address this question on a case-by-case basis.

Moreover, even with smart metering technologies in place, the willingness of consumers to participate in demand response, or the costs of compensating them for curtailment and load shifting, is uncertain. Effectively, the modelling scenarios described in Section 6.2.4 assume that given quantities of demand response can be shifted at no cost, which overstates the cost savings DR can achieve. Such costs may arise because consumers need to be compensated for the inconvenience of deferring/reducing consumption, and to realise sufficient benefits to make their participation worthwhile.

69 Communicating smart meters to customers – which role for DSOs?, Eurelectric, June 2013, page 6.

Irrespective of the costs of provision, it is clear that a necessary condition for the efficient provision of DR and storage by individual consumers and investors is that they be exposed to efficient market price signals, and some minor changes to trading arrangements might be required to ensure they do. For example:

- Any CPM implemented to correct for a missing money problem should not discriminate between large conventional technologies like large-scale power generation, and small scale technologies such as DR and small-scale storage[70]. Such discrimination could create distortions and inefficiency; and
- It may be possible to reduce the costs of participation through individual consumers appointing aggregators to offer their DR or small scale storage capabilities into the wholesale market. Removing licensing or logistical barriers to aggregators participating in the market might promote efficiency.

7.2.7 Efficient integration of regional markets

Sending efficient locational signals to market participants is also important for ensuring the investments required to accommodate renewables efficiently are made in the right places. For example, high renewables penetration may increase the extent to which periods of scarcity in EU energy markets are caused by swings in production from variable wind or solar technologies. To the extent that these swings in production are imperfectly correlated between markets, interconnectors can diversify supply and help manage variability by moving power from areas of relative surplus to areas of relative scarcity.71 In a competitive market with efficient price signals, the value of this service is reflected in price spreads between market zones, and the congestion rents earned by owners of interconnectors.

It is widely recognised that the “sharpest” locational signals are conveyed to market participants where wholesale prices are based on a system of locational marginal pricing (LMP), which is applied in the New Zealand electricity market and the PJM and New York markets in the US, for example. The modelling framework used for this assignment stops short of assuming full LMP, which applies nodal pricing, but rather uses a system of zonal energy pricing, with the main market areas defined as shown above in Section 2.2.

By defining transmission zones within which transmission constraints are limited, the model attempts to represent the intentions of the proposed Target Model for Capacity Allocation and Congestion Management (CACM). The Target Model imposes certain requirements on the forward market, day-ahead market, intra-day market and balancing arrangements, with the intentions of improving the efficiency with which transmission capacity is allocated, promote efficient trade between areas and sending more efficient signals to market participants:[72]

- *Transmission Network Capacity*: the Target Model requires a common approach to calculating capacity by either using a Flow-Based (FB) or an Available Transfer Capacity (ATC) method (in less meshed networks); CACM network codes will also have to define zones for capacity allocation and congestion management as bidding areas by taking into account overall market efficiency, which means that these zones will effectively be defined by reference to the location of transmission constraints and not national borders;
- *Forward Market*: the Target Model requires a market of explicit auctions of long-term transmission rights with either physical transmission rights (subject to use-it-or-sell-it) or financial transmission

70 It might be necessary to account for differences in (expected) availability in shortage conditions across different technologies.

71 This is reflected in the modelling results, which illustrate the potential value of developing new transmission (including interconnectors) to efficiently integrate renewable generation capacity. For instance, if we assume no further transmission is permitted, as Figure 101 illustrates, incremental costs rise considerably.

72 ACER, “Framework Guidelines on Capacity Allocation and Congestion Management for Electricity”, reference: FG-2011-E-002, 29 July 2011; Plug, Peter, “European electricity market: target model, infrastructure and security of supply”, presentation EEF workshop, 17 June 2011.

rights. The TSOs are also required to provide a single platform for allocating long-term transmission rights and secondary trading at European level;

- *Day-Ahead Market*: the Target Model requires implicit auctions for transmission capacity (market coupling) via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, which will also require the harmonisation of day-ahead bidding deadlines. Hence, energy prices would differ (i.e. markets would be split) where transmission capacity is congested, and a single price would apply within regions with no congestion. The price of transmission capacity (when congestion occurs) will consequently be defined as the difference between two zonal prices;
- *Intra-Day Market*: the Target Model requires continuous intra day implicit auctions for transmission capacity, which effectively means continuous trading of energy with real time prices reflecting locational marginal costs; and
- *Other Aspects*: the Target Model requires a move towards multilateral TSO cooperation in balancing and developing a common grid model for capacity calculation.

Depending on the practical implementation, the Target Model would therefore break the link between national borders and market pricing zones, improve the efficiency of trade between markets, and provide "sharper" signals to market participants regarding the value of energy, and how its value varies by location.[73] It may also promote more cooperation in the sharing of reserve capacity.

The Target Model stops short of requiring common market-based mechanisms for the procurement of ancillary services like operational reserves. However, the provisions of the framework Guidelines on Electricity Balancing[74] (FG EB) and the draft Network Code on Electricity Balancing (NC EB) go beyond the Target Model and explicitly call for the market-based procurement of operational reserves and balancing services and increasing regional integration. However, the FG EB still give preference for the use of interconnection capacity in the wholesale market, although an efficient allocation of interconnection capacity between the energy market and the sharing of reserves between neighbouring markets is explicitly mentioned. The modelling framework used in this report does perform an optimal allocation of transmission capacity between reserve and energy. Nevertheless, it is unclear whether the currently envisaged Target Model and the provisions of the FG EB and NC EB will deliver the price signals required to incentivise the investments that our modelling suggests are required to accommodate renewables efficiently.

7.3 Design of Electricity Network Regulations

Network regulation encompasses a range of topics relevant to ensuring the efficient integration of renewable power generation in the EU. Firstly, it covers the infrastructure access charging regime, which is important for sending efficient locational signals to network users. Additionally, the framework for the regulation of network companies must ensure the efficient level of investment takes place in distribution, transmission and interconnection to accommodate renewables expansion efficiently. We cover both topics below.

73 The Target Model will therefore reduce the extent to which congestion costs need to be managed by TSOs and then the socialised.
74 ACER. Framework Guidelines on Electricity Balancing. FG-2012-E-009. 18 September 2012

7.3.1 Efficient network access pricing

7.3.1.1 The importance of locational signals in network access prices

The costs of transporting electricity fall into two broad categories: fixed infrastructure costs and short-run marginal costs (congestion and losses), as defined below:

- **Infrastructure and Operating Costs**: In order to move power from one location to another, investors must build infrastructure including power lines, cables, transformers and other equipment. The cost of building and maintaining these assets depends on their capacity to transport electricity from one area to another and the distance over which this capacity is provided, regardless of any flow of energy over those assets.
- **Short-Run Marginal Costs**: Once energy starts to flow over the infrastructure assets, it imposes additional costs of two kinds:
  - **Constraint Costs**: Electricity transport costs show up as congestion within the transmission system when insufficient transport capacity is available to accommodate power flows. In a congested system, instead of using the transmission system to transport power from one area to another, expensive generators that would not be despatched in an uncongested system have to be despatched to ensure supply exactly equals demand in all areas. Output from other, cheaper generators, that would be producing electricity, must be reduced. In this case, electricity transport costs show up as the extra costs of altering the pattern of despatch to resolve constraints.
  - **Losses**: Losses are also a cost of transporting electricity between two locations. The further energy travels along a transmission line, the higher the proportion of the energy that is lost. This lost energy has to be replaced, at a cost, by increasing total generation output.

The mechanisms used to allocate these transport costs to generators and other market participants can affect their locational decisions. For both RES-E and conventional generation, as well as other technologies like interconnectors and storage, investors face a choice over the location of their projects. They can locate new generation where the costs of developing the project are lowest, for example where land prices are lowest and/or access to fuel sources is better or cheaper (or, in the case of wind generators, wind speeds are higher). Or they can locate new generation in more expensive locations that are closer to load centres, thereby reducing the cost of transporting their electricity to customers over the transmission network. All these costs differ greatly between different locations. Developers' choice of site therefore has a significant impact on the total cost of supplying electricity to consumers.

Signalling electricity transport costs to generators through energy and infrastructure prices gives them an incentive to make an efficient (i.e. cost minimising) trade-off between all the factors that vary by location. Making efficient trade-offs will minimise the joint cost of generation and transmission and hence total costs to consumers. The importance of efficient locational signals in power markets is illustrated by recent modelling work conducted by NERA and Imperial College, which shows that removing locational signals entirely from the British market would increase the costs faced by consumers by around £20 billion over the period to 2030 in NPV terms.[75] This cost arises because generation capacity locates where access to fuel or other costs are lower, and ignoring the transmission system costs or regional variation in the value of the energy they produce.

[75] Project TransmiT: Impact of Uniform Generation TNUoS, NERA and Imperial College, March 2011.

7.3.1.2 Locational signals in EU power markets

Energy pricing zones in most of Europe are defined by national borders, at present. This means that even if the value of energy varies dramatically within a country because of the presence of transmission constraints, generators still have the right to sell their output at a single national price. Moreover, generators often pay no transmission access charges,[76] and hence many markets currently send no locational signals to generators.

As discussed above in Section 7.2.7, the Target Model will enhance the locational signals conveyed to generators and other market participants by tying the boundaries of market pricing zones to the location of transmission links that are persistently constrained. However, even under this structure with locational energy prices, locational grid access charges may have some role to play.

For instance, even under the Target Model, the locational signals conveyed through energy prices will mask some variation in the locational value of energy, as the new transmission zones will only delineate areas of persistent congestion. Locational transmission charges could therefore provide a means of sending locational signals to transmission network users within market zones about the costs that their presence imposes on the system operator. Locational transmission access charges could be structured either as connection charges or as ongoing charges for grid access that seek to proxy the incremental investment costs required to accommodate a network user, or a combination of the two.

Another method of charging for transmission access is on the basis of "beneficiary pays", which has been advocated in the US by the Federal Energy Regulatory Commission (FERC). As described in a recent paper by Imperial College London and the University of Cambridge,[77] locational marginal pricing of energy (see Section 7.2.7) combined with "beneficiary pays" transmission access pricing has become part of "Standard Market Design" in the US, and is also applied in some South American power markets. Under this system, when a new transmission asset is proposed it will be paid for on the basis of who benefits from this investment, for example by earning higher energy prices for their output.

One important advantage of the "beneficiary pays" approach is that it may reduce the extent to which industry participants are incentivised to lobby for investments that are not economically efficient. In systems with zonal pricing of energy, parties that consume power in high cost areas or sell power in low cost areas will have strong incentives to lobby for increased transmission to zones with more favourable prices.[78] If transmission costs are to some extent socialised then network users will tend to lobby for transmission investments that will benefit them, irrespective of the cost. In contrast, beneficiary pays can help promote constructive engagement in transmission planning. Also, under the "beneficiary pays" approach, new transmission projects would only go ahead if the net benefits of schemes exceed the costs.

However, there are complications associated with this system, principally surrounding the identification of beneficiaries and the quantification of benefits. In 2011, FERC Order 1000 required a cost allocation methodology consistent with the principles set out below:[79]

1. The costs must be allocated "in a manner that is at least roughly commensurate with estimated benefits." The benefits include reliability, production cost savings, congestion relief, and meeting public policy requirements.

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76 As shown in a recent study by ENTSO-E, generators in across EU power markets typically pay no infrastructure charges at all, or only a very small share of total costs. Source: Overview of transmission tariffs in Europe: Synthesis 2011 (Updated June 2012), ENTSO-E, page 6.

77 Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery, Imperial College London and the University of Cambridge, Prepared for Ofgem, June 2013.

78 More favourable may mean either higher or lower, depending on the incentives of the market participant.

79 Docket No. RM10-23-000, § 586. Reproduced in FERC "Order 1000 & Public Policy Transmission Projects", NERA Economic Consulting (Ringelstetter-Ennis, S., and Heidell, J.), 5 March 2012.

2. "Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities."
3. If a benefit threshold is established for determining which projects have net benefits, that threshold should not be higher than 1.25, absent sufficient justification.
4. Costs for regional transmission projects cannot involuntarily be allocated to other transmission regions.
5. The methods for cost allocation, determining benefits, and determining beneficiaries "must be transparent with adequate documentation to allow a stakeholder to determine how they were applied…"
6. Different cost allocation methods can be used for different types of transmission projects. For example, the transmission entity has the option, but not the requirement, to establish different cost allocation mechanisms in their tariff for projects designed for reliability versus projects associated with public policy requirements.

Beneficiary pays therefore requires that a regulator or other centralised agency identify the avoided constraint costs, the primary benefit of increased transmission or interconnection, associated with particular projects, e.g. through the application of market modelling, and allocated benefits to parties. Although such modelling is possible, the outcomes may be contentious and the analysis conducted would entail some subjectivity. Additionally, the FERC's definition of "benefits" therefore also encompasses wider "public policy" benefits. Such a provision might allow transmission developments to promote policy objectives such as to support expansions in renewable generation, but the downside is that they add further to the subjective assessment of transmission benefits.

The complexity of the "beneficiary pays" approach is also illustrated by experience to date with the "Inter-transmission system operator compensation mechanism" as required under Article 13 of Regulation (EC) No 714/2009[80]. Although an inter-TSO mechanism has been in existence for more than a decade, European regulators and system operators have so far been able to agree on a mechanism that is acceptable to all countries and which can also be applied in practice.

Another complication associated with charging based on either incremental costs or beneficiary pays approaches is that they invariably result in total revenues that either over or under recovers the network company's regulated revenue entitlement. This means that some element of cost needs to be socialised, and the approach used to do so should ideally minimise distortions. Ideally, this can be done through schemes such as Ramsey pricing, whereby mark-ups are charged in proportion to users' price elasticity of demand for a product (here, network access). In essence, this rule allocates fixed or common costs to the parties with least discretion to change their behaviour, which often means domestic or small commercial consumers.

7.3.1.3 Efficient distribution pricing

Our modelling suggests that the assumptions made regarding the future deployment of distributed generation can materially increase or decrease the need for distribution reinforcements, as discussed in Section 4.4. The amount of DG deployed, type of DG (e.g. solar vs. small CHP), the location in the grid, and the coincidence of its production with local peaks in demand all affect whether DG increases or

80 Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003

decreases distribution network costs.[81] Another key driver of the need for distribution reinforcement is the behaviour of customers. Figure 128, for example, shows that wide-spread participation in DR programmes can materially reduce distribution network reinforcement requirements by reducing peak requirements.

The significant effects that network users' decisions can have on future distribution costs means it is extremely important that distribution charges reflect the costs that users impose. Efficient distribution charging will help to encourage the efficient deployment of DG, distributed storage, DR and in some cases, the efficient location of new load. Specifically, a distribution charging regime that sets tariffs equal to the incremental cost caused or avoided by the presence of particular users on the network will help to promote efficient decisions by users in different locations within distribution systems. In some cases, this might require that distribution charges be negative, for example where a user's presence on the system allows the network company to avoid costs. It may also require that distribution charges vary by location, type (i.e. generation/load), the user's peak consumption, and possibly other factors.

In theory a distribution charging mechanism based on the incremental costs of reinforcement can be defined based on detailed cost and load flow modelling of distribution systems. In practice, however, a charging regime that achieves this aim may be extremely complex, and would (potentially) require different distribution charges across many different locations in distribution systems. Many assumptions regarding the technical characteristics of the real distribution systems may be required to calculate charges, and regarding the characteristics and behaviour of network users. Despite these difficulties, incremental or marginal cost approaches are used in some parts of the US, e.g., California and Nevada, and in a number of European countries including the UK.

Distribution charges may also change significantly from one year to the next due to changes in network topography or the number, size or type of connected customers. Hence, distribution charges based on incremental cost may be volatile, and so increase the cost risks born by investors in distributed generation and other distributed technologies such as storage. It may be possible, however, to stabilise distribution tariffs volatility by offering distribution network users long-term access agreements with predictable tariffs set based on the expected costs they impose when they seek a connection.

7.3.2 Incentivising efficient investment

7.3.2.1 Attracting investment in regulated infrastructure

Most regulatory frameworks for transmission and distribution network owners in Europe operate by fixing price or revenue caps that define the level of allowed charges, with some reference to actual costs incurred by the company. Broadly, the aim of these regimes should be to strike a balance between minimising costs to consumers, and offering returns to investment that are sufficient to attract capital. Regulatory regimes also often offer quality of service incentives to incentivise the operator to maintain or improve standards of service to end users.

Across the EU, all regulatory regimes differ slightly in their detailed implementation, but to attract the investment required to integrate renewables efficiently that our analysis suggests is required, all will need to offer investors a reasonable prospect of cost recovery, including a return on the capital employed in the business. This rate of return should be calculated such that it is commensurate with opportunity cost of alternative investments with a similar risk profile as investments in the regulated network business. This condition creates a universal constraint of network regulation.

81 For instance, distributed PV in distribution network areas dominated by air conditioning load may reduce reinforcement costs by moderating growth summer peaking load. Conversely, installing solar PV in network areas where demand peaks to provide heat in the winter may not reduce, or may even add to, reinforcement requirements.

Identifying the rate of return that compensates investors for the risks they bear when investing in new network infrastructure is not straightforward. In this case, the significant expansions in transmission and interconnection capacity that our modelling indicates is efficient are likely to require significant anticipatory investments in assets with an uncertain future value. These anticipatory investments in new capacity may help accommodate renewables efficiently by exploiting scale economies and maximising the gains from trade. However, investors are also mindful of the risk of stranding, and will only invest if the rates of return available for investment in new capacity compensate for the risks that their asset will be stranded.

In competitive segments of energy markets, private investors can make informed decisions about the risks that the assets they consider developing will be stranded, or have low value. They do this by selecting investments with expected rates of return that are sufficient to compensate for such risks. In general, this process of decision making by private investors should result in investment decisions that manage risk and uncertainty efficiently.[82] However, in regulated segments of the market, regulation distorts the incentives to make anticipatory investments efficiently.

Traditional regulated networks have only been allowed to recovery relatively low rates of return on their investments, reflecting the protections created by regulatory contracts that have provided reasonable assurances of cost recovery. In many jurisdictions, these low regulated rates of return have been sufficient to attract investment in the ongoing maintenance and development of a range of network industries. But increasingly, as regulated network operators are being asked to make "riskier" investments, these low rates of return may not be sufficient to attract capital.

7.3.2.2 The challenge of incentivising "risky" investments in assets with regulated access pricing – the example of new interconnection

Consider the case of an interconnector transporting power from one market area to another. The value of this interconnector depends on the variance in prices between the markets it serves.[83] Its future value is therefore subject to risk because changes in the supply-demand fundamentals in the connected electricity markets are uncertain. For instance, the modelling shows that the need for interconnectors and transmission investments depend on the scale, type and location of new renewables deployment, but due to a range of policy uncertainties, the future scale of deployment of variable renewables is uncertain, and therefore so too is the value of new interconnection.

While the value of new interconnection is uncertain, the costs of developing new capacity are substantial, entailing large upfront investment costs. Developing a new interconnector today will only be viable for a private investor if the returns it expects to realise if variability increases the value of interconnection compensate for the risks of the low returns that will be realised if it does not. This commercial constraint creates a challenge for European regulatory bodies and prospective developers due to requirements that they offer regulated Third Party Access to the capacity their investments create.

The effect of regulated access pricing is often to cap the charges that third parties incur to use the interconnector. If the asset turns out to be used, then the owner will receive regulated access charges. If the asset turns out not be used, then it will receive less than these charges, or possibly nothing at all.[84] If regulated access charges obtained when the asset turns out to have high value are insufficient to

82 Of course investment decisions may not be efficient in the presence of market failures such as externalities and market power. We discuss policy measures to resolve these potential inefficiencies above.

83 This variance in prices between zones may arise as a systematic spread between a low cost and a high cost market, or because prices in the two zones are similar on average, but volatile from hour to hour with relatively low correlation between the prices.

84 For instance, interconnector capacity is often sold through periodic auctions. However, often these auctions are subject to either formal price caps that limit the returns captured by the investor. Even if the auction prices are not capped, the regulated infrastructure providers are sometimes required to recycle any profits earned in these auctions in excess of a regulated return back to final customers through reductions in other regulated tariffs.

reward the risks taken by the investor that developed the capacity, it will deter investment *ex ante.* It is therefore clear there is a case for setting the allowed returns included in access prices above the levels earned by regulated transmission and distribution companies. However, setting access charges too high may cause overinvestment (or gold plating) and unnecessarily increase the costs incurred by end-users.

From the perspective of prospective third party users of the new interconnector, uncertainty over future value creates little or no risk. If the value of interconnection capacity between markets turns out to be low, they are under no obligation to purchase capacity. They only incur costs if they decide purchasing new capacity is worthwhile. In this sense, the option of purchasing capacity on a third party access basis provides users with insurance against the uncertain future value of capacity. Access prices based on low regulated rates of return fail to factor in the value of this insurance, or the cost of providing it.

From the perspective of the developer, the cost of providing this insurance depends on the market risk that influences the future value of capacity, which it must consider how to price when taking investment decisions. One approach to this valuation problem is through the application of real option theory. By investing in new interconnection before fundamental uncertainties have been realised, it is also forgoing an option to wait until future value is less uncertain. The value of this foregone option can be incorporated into the hurdle rate required for new investment. Only if regulated access charges allow rates of return commensurate with this required hurdle rate will new investment be profitable.

This challenge has been recognised recently by the European Commission and ACER. For instance, the TEN-E regulation states that "*Where a project promoter incurs higher risks for the development, construction, operation or maintenance of a project of common interest* […] *compared to the risks normally incurred by a comparable infrastructure project, Member States and national regulatory authorities shall ensure that appropriate incentives are granted to that project*".[85]

To set "appropriate incentives", some regulators have offered a premium on the WACC allowed for developments of new interconnection capacity, as summarised in a. Other regulators, e.g. Ofgem in Great Britain, have chosen WACC values near the top of the range for reviews with "investment focus".

However, the calculation of the required premium of the WACC for anticipatory investments has often lacked an objective analysis of the risks faced by the investor. Such proximate methods for setting WACC premiums raise the concern that the returns offered will be either too low, thus deterring investment, or too high, leading to excess supply of new capacity. One solution to this problem developed in the telecoms sector involves the use of a real options approach to estimate the premium on the WACC required to remunerate investments in Fibre to the Home (FTTH) technology, the demand for which is uncertain.

85 REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009, 15 March 2013, art. 13(1), 3.

Table 26 Examples of WACC Premia for New Investments

Jurisdiction	WACC Premium Allowed	Assets Covered	Stated Reasons
Austria *Electricity distribution and transmission*	+1.05% p.a. /+1.5% p.a. on WACC	All new investments / enhancement investment	Additional incentive for investment / incentives for increasing coverage
France *Gas transmission*	+3% p.a. on WACC	All investments that lead to the creation of additional capacity on the network	Increased security of supply, network stability
Italy *All Network Types*	+1% to +3% p.a. on WACC, depending on the type of investment	New investments intended to develop infrastructure	Modernisation of the network, expansion in rural areas, new connections
Portugal *Electricity*	+1.5% p.a. on WACC	All new investments	Incentivise investment & promote efficient management
USA *Electricity Transmission (FERC)*	+ 0.5 to +2.0% p.a. on RoE	'Non-routine investment' ('large' has qualified in past)	Increased reliability or reduced congestion; avoiding financing problems

Source: NERA Research

7.3.2.3 Overcoming barriers to new interconnection

The benefits of interconnection in assisting with efficient renewables integration are essentially the same as for other forms of transmission, i.e. interconnectors transport energy from low price areas to high-price areas. Hence, the measures set out in Section 7.2 above to improve the efficiency of price signals in the energy market, and possibly a capacity market too, will also help support the development of new interconnection. Offering returns to investors in interconnection commensurate with the risks they bear is also an important step to attracting investment.

However, the commercial regime facing interconnector owners can be considerably more complex than the regime facing transmission owners due to the interaction with regulatory frameworks in more than one nation state. Hence, political and institutional factors in neighbouring markets can affect the economic viability of developing interconnectors, even if underlying market conditions would support their deployment.

For instance, some alignment of market organisation (e.g., gate closure and trading intervals) may support efficient arbitrage and hence the efficient development of interconnection. Differences in infrastructure charging arrangements across jurisdictions may also distort incentives to efficiently locate generation, load and other more innovative technologies like storage. Increasing harmonisation of infrastructure access charging may therefore support the efficient integration of renewables in the EU as a whole.

Finally, it is well-known that the benefits of interconnection can in some cases be asymmetric; power prices in the high cost market fall following interconnection to a low price market, while prices in the low cost market rise. This problem does not affect commercial incentives to invest efficiently in interconnector capacity to arbitrage price spreads, but it can lead low cost markets to resist development of interconnection, and so inhibit efficient investment (i.e., investment that produces gains from trade), in order to protect their consumers from higher prices.

One solution to this problem is to expand the role of EU-level entities in transmission planning. However, we anticipate that it will remain difficult to entirely prevent individual Member States from blocking new interconnection investments that are not in their own interests while they retain responsibility for planning and consenting of new transmission lines, or for regulating the rates of return that interconnector developers are allowed to earn. If such institutional factors turn out to be a barrier to investment in new interconnection, it may be that competing technologies such as increasingly flexible power generation, DR and storage have a greater role to play in efficiently integrating renewables into the EU power system.

7.3.2.4 Changes to network planning standards

Another important aspect of incentivising efficient investments in network infrastructure are the planning standards to which network operators are required to adhere. Network operators have traditionally planned their networks around a need to meet peak demand requirements. In some cases, the need for network reinforcement will no longer be driven by the need to accommodate network flows in peak demand conditions, but to accommodate exports from variable power generators in windy or sunny conditions.

In some jurisdictions, achieving efficient investments to provide both peak security and an efficient quantity of capacity to accommodate renewables in off-peak periods may require amendments to existing network design standards. For instance, rather than mechanistic rules requiring companies to meet pre-defined planning standards at peak time, it may be more efficient to require that transmission and distribution companies conduct cost-benefit analyses for proposed investments. This would help to promote transmission investments that make a least-cost trade-off between constraint and investment costs over the year as a whole, i.e. accounting for both peak and off-peak conditions, which theory suggests is the optimal approach to selecting investments.

Another development that may affect the need for new network capacity, as the modelling illustrates, is the emergence of "smart grid" technologies, including DR and storage. A large value driver for these types of asset is their role in helping to avoid or defer distribution and transmission investments. Wherever possible, distribution and transmission companies should be offered financial incentives to minimise costs over the life of the asset, which would in turn provide incentives for an efficient mix of conventional reinforcements and smart solutions.

However, in reality companies may be have weaker incentives to innovate and integrate smart solutions, preferring to deploy more conventional reinforcements even where a smart solution would be cheaper. One way to counter this issue is to offer direct funding for R&D programmes conducted by grid companies to help reduce the cost risks associated with nascent technologies. For instance, in the UK, as part of its Innovation Stimulus programme, Ofgem has introduced the Network Innovation Allowance (NIA) and Network Innovation Competitions (NIC) from 2013. These schemes provide funding for demonstration of smart technologies.

Another approach may be to write into companies' licences or applicable laws an obligation on companies to show they have considered smart solutions as alternatives to conventional reinforcement investments when they seek approval from regulators to undertake CAPEX projects. Typically, companies have to justify the need for investments they undertake with reference to the benefits delivered by that investment when seeking regulatory approval to add it to their regulated asset base. In most jurisdictions, it would be relatively straightforward to add as a condition for approval of investments that companies demonstrate they have considered the use of technologies that can substitute for reinforcement.

7.4 Design of Renewable Electricity Support Policies

This Section considers different policies designed to support renewable electricity, relative to more conventional forms of generation. Section 7.4.1 provides an overview of the need for policies to promote renewables, and summarises the types of policy that have been (and could be) used.

7.4.1 Overview of RES-E support policies

Currently, most RES-E is more expensive than electricity from conventional sources on a levelised cost of energy basis. This is projected to continue for the foreseeable future, and this is reflected in the modelling results presented in Chapter 5. Although by 2025 and 2030 some capacity in some regions appears to be competitive with conventional generation and would earn sufficient revenue (or more specifically, operating margin) from electricity generation to pay for and provide the necessary return on its capital costs, most RES-E generation capacity is unlikely to be financially viable in this way without some form of subsidy.

Across the EU, each Member State currently applies its own RES-E support policies, and harmonisation is essentially non-existent. The most common RES-E policies are either output- or price-based, and many policies are a mix of the two. In addition, capacity-based policies have also been used in the past. Box 1 provides a very brief (and non-exhaustive) overview of the RES-E policy instruments applied by the Member States.

Box 1: RES-E Policies in the EU

- Feed-in-Tariffs (FITs) are the most common RES-E support instrument in the EU: Under FITs RES-E is fed into the grid with priority and remunerated according to a fixed cost-based technology-specific tariff. Usually, the tariff is guaranteed for a specified time limit (in many cases up to twenty years). Pure FITs systems are used in Austria, Bulgaria, Cyprus, France, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, Portugal and Slovakia. In addition, the Czech Republic, Estonia, Germany, Malta and Spain also use FITs, in combination with other policies such as PTs. FITs are also used in the UK and Italy, in combination with RECs.
- Premium Tariffs or Premium FITs: Under a premium tariff system, renewable electricity is sold in the wholesale market, and generators receive a fixed premium in addition to the electricity market price. Premium systems are used in Denmark and Finland.
- Contracts for Differences (CFDs): Under a CFD system, renewable energy generators receive the difference between a cost-based technology-specific "base level" and an index reflecting the average electricity market price. A type of CFDs is used, for example, in the Netherlands.[86]
- Renewable Energy Certificates (RECs): Under a RECs system, each generator is obliged to fulfil a renewable quota for the electricity sold. He can either achieve the quota with his own RES-E plants or by buying certificates that certify RES-E based electricity generation. Renewable energy generators receive one certificate for each unit of renewable energy they produce. In the EU RECs have been used in Italy, Poland, Romania, Sweden (which has also linked to Norway) and the UK (through the Renewables Obligation).
- Capacity Procurement Auctions (CPAs): An alternative support system for renewables relies on central procurement based on competitive tenders. Examples of tender schemes are bids for a pre-specified volume of RES-E capacity (or projected output) – which can be regionally and technologically differentiated – in descending clock auctions, or generation procurement auctions, such as bids for a quantity of output at a pre-specified price. Tender schemes are not used any longer as the dominating policy scheme in any Member State, but in some cases they are used for specific projects or technologies (e.g. wind offshore in Denmark).
- Hybrid Instruments: As noted above, many European countries apply a mix of the aforementioned regulatory instruments: Czech Republic, Estonia, Germany, Italy, Malta, Netherlands, Spain and the UK. Examples of hybrid features include REC systems with price floors / ceilings, or FIT systems under which support levels adjust in response to higher or lower volumes of uptake or output. [87]

7.4.2 RES-E policies: incentives for efficient investment and operation

This Section considers the efficiency and inefficiency of different policies and policy designs that may be used to support RES-E. We consider a variety of different areas where inefficiencies can arise as a result of such policies, including inefficiency in the provision of and response to short- and long-run carbon price signals, inefficiency in the provision of supply security, inefficient incentives for innovation, inefficient choices among different RES-E investments, inefficient operating decisions for RES-E technologies, and inefficient location decision for RES-E investments.

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86 Radov et al. "Options for a Renewable Energy Supplier Obligation in the Netherlands." NERA Economic Consulting 2013. (http://www.nera.com/nera-files/PUB_RenewableEnergy_Netherlands_0113.pdf)

87 Except where additional sources are cited, this box relies on policy summaries contained in Ragwitz et al, "RE-Shaping: Shaping an effective and efficient European renewable energy market", February 2012.

This Section first considers whether it is efficient to set a RES-E target, and then considers, given a commitment to support RES-E for the sake of being RES-E, how to support different types of RES-E efficiently, and how to encourage efficient geographical placement of RES-E.

7.4.2.1 Efficiency considerations related to defining a RES-E target

Investment in RES-E in Europe currently receives support both through the carbon price as well as country-specific policies designed to achieve each country's share of the 20 percent target by 2020. In keeping with our definition of efficiency, we consider policies that support RES-E to be efficient to the extent that they encourage the investment and operation of RES-E to the point where the marginal benefit from RES-E output equals that output's marginal costs. In this Section we discuss the arguments for explicitly supporting investment in renewable electricity generation.

If concern over GHG emissions were the only reason to support the development of RES-E capacity then – subject to certain qualifications that we discuss in more detail below – economic theory would suggest that *separate* RES-E support policies are not required to achieve this objective efficiently. Setting a separate RES-E target imposes a fixed share of renewables on the EU – whether optimal or not. A carbon price alone would ensure that the correct level of renewable energy was deployed, possibly in combination with other abatement measures such as energy efficiency, nuclear power, etc., so that targeted emissions reductions would be delivered in the most cost-effective manner. Any additional support for renewables beyond this level would undermine incentives for emissions cuts to be made via other measures.

However, policy makers may seek to justify separate renewable support policies on the grounds of satisfying additional goals – often set out in terms of the EU's wider climate and energy policy. As discussed above, these goals include enhancing security of supply, reducing energy bills (for both the residential sector as well as commercial and industrial customers), and developing expertise in low carbon technologies that can drive growth and job creation. The EU Climate and Energy Package establishes a target for the share of final energy consumption to be sourced from renewables by 2020. The policy framework beyond this, out to 2030, is currently under consultation, considering the merits of multiple policy instruments, targeted objectives and the extent to which policy should be formulated at national or regional levels.

The modelling results presented in Figure 94 of Section 4.5.4 actually show that higher levels of RES-E support do not necessarily lead to deeper (or cheaper) reductions in carbon emissions. In Scenario 1 (the High RES-E scenario, in which RES-E accounts for 68 percent of electricity output in 2030), emissions are actually *higher* than in Scenario 2 (the moderate RES-E scenario, based on the 2050 Energy Roadmap's "Diversified Supply Technology" scenario, in which renewable electricity accounts for 59 percent of electricity output in 2030). This is because the higher carbon price in Scenario 2 reduces coal output sufficiently to reduce emissions below the level observed in Scenario 1. The incremental cost of both scenarios is similar. This result illustrates that there may be approaches to decarbonisation that do not specifically target high levels of RES-E, and that are more cost-effective than those that do.

Distinct tools to address distinct market failures

From the perspective of standard economic theory, specific policy intervention to deliver on the objectives of energy policy should be based on the premise that there are market failures that would not be corrected without the intervention – otherwise the intervention will not be efficient and will not enhance overall welfare. There may also be arguments on the grounds of *equity*, or distributional fairness: that is, in the absence of policy, there are undesirable distributional outcomes – we return to these below. Distinct market failures tend to require separate policy instruments to promote efficiency. Possible market failures or other concerns that might be (partially) addressed by separate support for RES-E include:

1. Absence of long-term carbon price signal

   Investments in electricity generation technologies, particularly RES-E, often involve significant upfront costs that are then recovered over time as the plant is operational and earns a margin on its output. Policy certainty is therefore a significant influence on the decision to make any investment that has a long payback period. Proponents of separate renewable policies sometimes justify them by arguing that the carbon price does not provide sufficient certainty to encourage investors to make the considerable upfront commitments to funding RES-E projects. For example, the current EU ETS has been criticised for providing limited certainty to investors beyond 2020.[88] However, the operating lifetime of power generation plants built today will extend well beyond this. National level renewable support policies, on the other hand, tend to legislate for support over a much longer period, approaching the expected lifespan of the technologies.

   The European Commission and European governments have set out their ambitions to target carbon emission reductions until at least 2050 and have stated their intention to use a carbon price as the main regulatory instrument to deliver this ambition.[89] If the market is operating efficiently, but the price is too low to stimulate a certain level of investment in RES-E, then this simply means that there are less expensive ways of keeping emissions below the targeted level (or cap). However, if government pronouncements today about the long-term carbon targets (and the corresponding implied prices) are not viewed as credible by investors, this may lead to investor behaviour that makes decarbonisation more expensive in the long run. Consequently, if today's investments assume a carbon price that is lower than what it would be if policies were perceived to be fully credible, there could be an over-reliance on conventional generation plants and an under-reliance on RES-E and other low-carbon technologies. This could significantly raise the cost of carbon emissions mitigation efforts over the longer-term, provided that the emission reduction targets remain as proposed.

2. "Under-provision" of energy security

   The term "energy security" corresponds to various notions of control that a country or region holds over its supply of energy. This may relate to the reliability of supplies from outside of the region, for example the EU, the affordability of these supplies, or the resilience of delivery infrastructure to natural or man-made disruptions. There are several measures by which energy security may be assessed. Indicators include import dependency on fuels, the stability of supply routes, the reliability and efficiency of generation, distribution, and transmission infrastructure, or the degree of self-sufficiency in energy supply.

   Threats to security of energy supply tend to originate outside of the borders and direct influence of the EU. If there is "insufficient" provision of indigenously sourced energy then the EU may be susceptible to supply disruptions, leading to either severe energy price spikes or outages, which in turn have negative knock-on effects in terms of both economic output and social welfare. Given the range of different indicators of energy security, and the uncertainty regarding the measurement of risk, it is not clear what a *sufficient* level of domestic energy provision would be. This is perhaps one reason why the EU has not established explicit energy security targets.

   In theory, the extent of the risk of security concerns should be considered by investors when deciding on what generation technologies to build. For example, an investment into a CCGT plant

88 We note that the concern about "uncertainty" may be more accurately characterised as a concern that the expected price is not high enough to justify certain lower-carbon investments.

89 As set out in the Low Carbon Roadmap to 2050.

would include some provision for not being able to generate in any given period due to a lack of gas. Likewise, a wind farm developer may expect that the wholesale electricity price, determined by the marginal cost of fossil fuel generation plants, may rise in certain periods due to energy supply constraints. However, a market failure exists where private investors fail to consider the full social costs of these risks within their decisions. Under-provision of security in the energy system by private actors may occur where there is a relatively low risk of supply disruptions, but a high negative impact on welfare where they do occur. There is therefore a case for governments to insure against such outcomes, rather than private investors that are less likely to be attracted by such uncertain and infrequent returns.

RES-E can increase indigenous energy production, decreasing dependency on fuel imports from outside of the EU. However, RES-E is only one means of delivering improved energy security, alongside factors such as diversifying supply routes, further liberalisation and integration of the EU's internal markets, and technical developments such as smart grids and increased electrical storage potential. If RES-E is to be supported to reflect wider security of supply benefits that are not appropriately compensated through existing markets, then it is important to ensure that other means of promoting energy security are supported to similar degrees. Ensuring this level playing field may be difficult if support comes via targets or support policies that are aimed exclusively at RES-E.

3. Competitiveness of low carbon technologies

Competitiveness and growth are often cited as further justifications for supporting RES-E technologies. Policy makers have identified the low-carbon sector as a developing area in which the EU should be able to compete on a global market, and export its expertise. The immature nature of many RES-E technologies mean that research and development activities – as well as scaling up the volume of deployment – may yield significant cost reductions and other benefits that have spill-over effects. However, without policy support, individuals and companies may under-invest in RES-E (relative to the social optimum), if they are unable to capture the full benefits of technological improvements.[90]

Whilst R&D spill-overs may justify a degree of market intervention, the case for government support for RES-E as an opportunity for growth and job creation is less clear. Recently the EU has not been at full employment and has been experiencing a period of negative or negligible growth. Therefore, public-led investment providing employment may provide short-term economic benefits. However, underemployment is likely to be a cyclical problem, and may not be as relevant for policies with a 20-year or longer horizon. Public sector support is most efficiently utilised where it yields the greatest return in terms of social welfare. In terms of growth and job creation, investment in RES-E support policies is justified on efficiency grounds only to the extent that the sector is more productive and generates greater social benefits than funding in other areas of the economy.

Recognising that there are multiple market failures that might be partially addressed by supporting RES-E, in theory the most efficient policy approach would be to set up separate instruments to address each market failure. These instruments, which would include a headline carbon target, would provide the efficient level of investment support in RES-E, without an explicit target for RES-E itself. For example, one or more measures of energy security, such as import dependency, could be explicitly targeted. Therefore, an efficient market design to achieve a prescribed level of energy security would need to incorporate a range of solutions that deliver the objective at the lowest possible cost, ensuring that RES-E is not over- or under-used in achieving the target.

90 This market failure is by no means unique to innovations in the RES-E market, of course. Although it may improve overall welfare to support R&D for RES-E, it may be even better to support R&D in other areas.

There are clearly challenges associated with designing and coordinating such instruments. To enhance the credibility of the carbon price, specific long term targets could be firmly embedded in legislation, although this could limit the flexibility of policy makers to react to changing conditions. For energy security, complicated decisions are required regarding metrics and the desired levels of the objectives being promoted.[91] Global trade rules may limit the possibility of explicitly promoting indigenous production, for example – and in any case, complete energy self-sufficiency would be prohibitively costly. Deciding the efficient level of energy imports into the EU would involve quantifying the precise risk associated with the EU's various energy sources now and into the future. The separate instruments would also need to allow for implicit interactions and trade-offs amongst the objectives, adding further complexity to the policy decision. But this only underscores the value of flexibility in achieving a given target via various means.

Additionally, it is important to note that RES-E comes in different forms that vary in terms of how they support the delivery of EU Climate and Energy objectives. Decisions need to be made amongst the different RES-E options in order to pick the most appropriate technologies. For example, per unit of output, certain types of biomass may reduce carbon emissions less than solar or wind power. Different RES-E technologies also may depend on foreign trade in different ways – again, biomass may be imported on an ongoing basis, whereas other forms of RES-E capacity may be imported at the construction phase only. Technology neutral RES-E support policies, that allow the market to select technologies, are arguably more desirable because they shift the decision making onto the private sector. Private sector participants have direct knowledge and experience with the available technologies and therefore should be more informed than government bodies. However, where there are significant R&D spillovers investors may be deterred away from technologies with significant potential for cost reductions. Government intervention may therefore be justified in order to develop technologies to reach cost competitiveness as quickly as possible.

Given the uncertainties about what is the "right" level of RES-E to be deployed over time, it seems prudent, where possible, to establish policy frameworks that make it possible to achieve the relevant objectives using an appropriate balance of RES-E and other technologies and solutions – rather than imposing a level of uptake (or level of subsidy per unit of RES-E output) that may not be justified by the corresponding externality benefits. However, designing and implementing alternative markets, as sketched in the previous paragraph, to improve energy security or job creation, is a complicated task. If the markets are not set up correctly they would run the risk of creating further distortions as well as uncertainty. Technology-specific support for RES-E may deliver the desired benefits via a simpler, if inefficient, mechanism. This is unlikely to be optimal but may be more effective once the considerable administrative costs of alternative instruments are taken into account.

Summary

Overlapping policies often create inefficiencies and make it difficult to assess their individual effectiveness. To the extent that renewable deployment serves to meet multiple objectives and acts as the partial solution to several aims, there is the potential for the existing range of climate and energy policy instruments to be excessively costly (and inefficient).[92] By explicitly targeting RES-E, EU policy makers are unlikely to design the optimal support mechanisms, especially as they are delivered through a mix of uncoordinated individual national policies.

91 Boehringer & Keller (2011) discusses several of these challenges with a specific focus on security of supply.
92 This is shown by various modelling results assessing the EU 2020 targets. For example, see Löschel et al. (2010).

However, if there are market failures beyond the absence of a carbon price, then the EU ETS (and/or extensions designed to give greater long-term visibility to the carbon price) alone will not address these. RES-E has a role not only in mitigating carbon emissions, but also in mitigating the risk of insufficient energy security, and (under certain assumptions) could improve welfare through stimulating growth. But ensuring that RES-E support is not excessively costly depends upon how policy is designed to encourage specific technologies. The following Section examines the different options for providing separate RES-E support and, at a more granular level, which policy mechanisms can ensure the most cost effective selection of specific RES-E technologies.

The modelling results presented above in Section 5.3 suggest that onshore wind is cheap enough to cover its costs in a number of EU markets. If there is to be a separate RES-E support policy, this raises the question whether that policy should exclude onshore wind from its support. In general, under what circumstances does RES-E (or certain types of RES-E) stop being treated as "special"? Even by 2020, some RES-E in some applications is expected to be cost competitive. If RES-E is treated differently from other output / capacity (with similar low-carbon, indigenous supply, job-creation characteristics), it is not clear that *already competitive* RES-E should be eligible for such special treatment, simply because it happens to be RES-E. (Currently large hydroelectric and/or pre-existing hydroelectric capacity does not receive RES-E support in many countries.)

As RES-E becomes an ever greater part of the overall generation mix in coming years, there are significant questions about maintaining existing "special treatment" of RES-E supply. How should RES-E policy choose which technologies, locations, or projects to support (and which not to support) in a way that is not arbitrary? If not all RES-E options are of equal merit, what features can be used to reflect this in objective ways? For example, there are concerns that (large-scale) biomass plants may be "less renewable" (and more CO_2 intensive) than other technologies, as both depend on the management of the biomass source on which they rely. Onshore wind and large-scale solar power are considered by some to have negative impacts on the landscape and wildlife. Issues such as these highlight the desirability of moving towards simpler, streamlined policies that treat all generation sources the same. If sources are to be rewarded for desirable non-market outputs, these same rewards should be available to all sources that deliver these outputs.

7.4.2.2 Efficiency of different RES-E support policies to achieve RES-E targets

The previous Section discussed the desirability (or not) of supporting generation technologies solely because they are classified as "renewable". If the decision is made to support "being renewable" in this way – for example, via the continuation of target-setting for the contribution of RES-E to the energy system – then the economically efficient way of achieving a given RES-E target would be establish a policy in which the marginal unit of RES-E output required to meet the target received the support necessary to cover its marginal cost of production (relative to the cost of conventional sources).[93] If all RES-E output were eligible to receive this support, this would ensure that only projects or technologies whose generation costs were below this level would have incentives to build and operate. This would allow the target to be achieved at lowest cost. Just as setting a uniform carbon price provides a level playing field for different actions that reduce emissions, a uniform RES-E support allows for fair competition between RES-E projects that may contribute to meeting the target.

As suggested in Box 1 above, RES-E policy options can be quantity-based or price-based. Price-based policies include FITs and premium payments, and variations on these such as contracts-for-differences

93 The policy would need to cover both short-run and long-run marginal costs, although in theory these could be done through different mechanisms.

(CFDs). Quantity-based policies include uniform “green certificate” mechanisms, as well as variations of these such as banded certificate policies; capacity-based systems may also be thought of as quantity-based. Currently a wide range of policies and policy hybrids are being used by the Member States.

In a world where there is perfect competition and perfect information about current and future costs, demand, etc., economic theory suggests that there should be no difference between the final impacts of the different types of policies. For example, under a uniform feed-in-tariff (under which all renewable electricity generators are paid a fixed, identical amount for the renewable electricity they produce) setting the tariff level equal to the levelised cost of energy of the most expensive resource required to meet the target would ensure that the target is achieved using the least expensive projects. This would also be true in the case where a uniform renewable energy certificates policy was used (under which all renewable generation receives a single REC whose price is determined by the market).[94]

However, in the real world we cannot assume that governments or investors have perfect information about the present or the future. Different policy designs respond in different ways to unexpected developments, so they depart from the efficient outcome once the world departs from current expectations.

Governments and even investors do not know for certain which projects and technologies are actually required to meet RES-E targets, or what their costs will actually be, or how they compare to those of other ways of meeting the targets. Errors in estimation of generation costs (and in the identification of the types of project and technology that are judged to be necessary) may lead to the RES-E target not being met, or being exceeded, or being met inefficiently.[95]

Uncertainty exists not only about RES-E costs and performance. It also exists for electricity prices. For example, an unexpected increase in the price of gas may lead to an increase in electricity prices, making it more attractive for RES-E technologies to generate. Or alternatively, higher-than-expected wind output may drive electricity prices down, decreasing the need for other, more expensive, renewable generation. When such circumstances occur, electricity prices transmit signals to generators about the economic value of output, and these are passed on to RES-E generators under premium FIT policies and under REC policies.[96] On the other hand, under FITs (and to varying extents under CFDs) revenues are not linked to electricity prices, leading all technologies whose marginal cost is below the FIT to have incentives to generate whether or not they are “needed”. Hence, total renewable generation may depart from the economically efficient outcome.

Because they have different effects once uncertainty of outcomes is taken into account, the different policies also imply different risks for RES-E investors and operators and for governments. Investors may require different rates of return for different risk profiles. For example, at one extreme, fixed FIT regimes do not expose RES-E capacity to any price risk, whereas CFDs, premium FITs, REC policies do, in different ways.[97] The relative risks imposed by different policies may mean that investors demand a lower return for policies that expose them to lower risk. This “return” is an opportunity cost of capital

94 And similarly, in the hypothetical case of perfect information, the same would be true of a *premium* FIT policy.

95 Under a uniform FIT, for example, underestimating generation costs may cause investors to be unwilling to develop sufficient projects. In contrast, overestimating costs could lead to unnecessary, expensive, technologies, being built. Similar errors may affect investment under REC systems, although because the REC price adjusts automatically to surpluses and shortfalls, the target is expected to be met, but may be met inefficiently. Because investors may have better information about project costs than governments, information uncertainty about project costs may affect quantity-based systems less than price-based systems.

96 Under RECs, certificate prices tend to adjust, to some extent, to reflect changes in electricity prices, hence mitigating the strength of the signals provided by electricity prices. See the next footnote.

97 Under a CFD policy, generators may be exposed to hourly fluctuations in the electricity market price if the index is not computed at an hourly interval. Depending on the design of a CFD, generators that tend to operate during low price hours may expect lower-than-average revenues. Under REC systems, generators may be protected somewhat from fluctuations in the electricity market price because if electricity prices fall, certificate prices may be able to adjust to compensate for the difference in revenues. The relationship *between* the REC price and the electricity price is therefore a critical determinant of the amount of risk that RES-E sources face under REC regimes.

that should be counted in social cost benefit analysis as a social cost. There may be arguments for designing policies that reduce this cost – as long as it is recognised that risks are almost always transferred between investors, government, consumers, and other parties, rather than being eliminated.[98]

Risks whose burden falls differently depending on the design of the RES-E support policy include: electricity (and fuel) price risk, subsidy revenue risk, system imbalance / curtailment / variability risks, and technological progress risk.[99]

The discussion above focuses only on whether each policy can achieve a given RES-E target in an economically *efficient* way. This ignores a further aspect that tends to be critical in policy design, however: the distributional impact of different policies. In practice, the main driver of policy design in the EU and elsewhere has been not efficiency, but the impact on (retail) prices and energy end-users' bills.

In competitive markets, the price received by the marginal producer is necessarily higher than the production cost of other producers. This creates producer surplus, which is a standard feature of liberalised markets, but which may be perceived as "excess profit" that has undesirable impacts on end-user bills.[100] One implication of the uniform FIT and uniform REC policies outlined above is that low-cost RES-E supply receives revenues well in excess of its costs, which increases consumer bills more than would be necessary if the government had been able to "price-discriminate" among the different RES-E options.

Many investors may have been willing to invest in some projects or technologies at an implied level of policy support much lower than what they actually received. There are several mechanisms that have been used to mitigate this effect, such as setting different, technology-specific FITs or providing fewer certificates per MWh produced to less expensive resources ("banded" certificates system). There is, however, a trade-off between reducing consumer impacts in this way and achieving the target in an efficient manner.

In particular, any of these mechanisms presupposes knowledge of the generation costs of each RES-E technology. However, as discussed above, perfect knowledge of costs is not possible, which may lead to several inefficiencies in the outcome. For example, if costs for a less expensive resource such as onshore wind are underestimated, so that investors are unwilling to develop projects, the target may eventually be met through other, more expensive, technologies. Even if FITs or certificate bands correctly represent the generation costs of the "average" technology, if there are significant differences between the FITs/number of certificates offered to different technologies and there is variation around the average cost that causes technologies to overlap in terms of cost, technology-differentiation may lead to inefficient investment in more expensive technologies. Under all these circumstances, the target would not be reached in an efficient way.

The modelling results presented above in Section 5.3 suggest very significant rents for the "maximum margin" RES-E technologies in each category in most years post-2020 across Scenarios 1-3. This is especially true if RES-E policies provide the same support to the highest margin capacity (in each technology group) as to the lowest-margin capacity in each group (which does not cover its investment

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98 See "Options for a Renewable Energy Supplier Obligation in the Netherlands" (Radov et al. from NERA Economic Consulting, January 2013), which includes a review of the impact on investor risk premia of different support mechanisms.

99 This is the "risk" that technological improvements lead to changes in costs that are more or less rapid than originally anticipated. Rapid RES-E cost reductions can expose investors to significant losses if the support to RES-E technologies is linked to a certificate price, as the price of certificates can fall significantly as technology costs fall. Equally, if costs do not fall as rapidly as expected, there is a potential upside. Governments may be better able to accept this risk than individual investors – as they stand to benefit from rapid cost reductions that allow them to meet their targets more easily.

100 Distributional issues often figure prominently in policy debates, focusing on the total subsidy costs of the different policies, as well as the effect that these have on final prices supported by consumers. Hence, limiting total subsidy costs, and "excess" profits from support payments or revenues, should also be considered when comparing different RES-E support policies.

cost, or even its fixed O&M costs in some cases). Such "over-compensation" of low-cost, high-value projects may be unpopular, and may result in higher end-user price impacts, depending on policy design. On the other hand, it may improve efficiency – including dynamic efficiency, by providing incentives for innovation. This trade-off will need to be studied further, and then weighed in the wider policy context.

It is also worth clarifying that the modelling results presented in Chapter 5 do not attempt to minimise the cost of achieving specific RES-E targets. Instead, the scenarios assume that a certain amount of RES-E output is produced, and the model compares the incremental cost of achieving the associated level of RES-E and other output. As such, the modelling does not account for the specifics of RES-E support policies, or the inefficiencies that they may propagate. It is possible to compare the total costs of achieving the desired RES-E output levels under different technology mix scenarios (for example, comparing Scenario 1 to Scenario 1-DG or 1-LD). However, because these scenarios differ in their assumptions about technology costs, the results provide only limited insight into the inefficiencies that can be introduced by investing in RES-E technologies that are more expensive than necessary.

7.4.2.3 Providing incentives for efficient location decisions

A final issue that will be critical to address as the EU begins to source ever higher proportions of its energy from renewable sources is that the *location* of the resources may have a significant effect on the both the costs and benefits of its output, which we also discuss in Sections 7.2.7 and 7.3.1.

Efficient development and operation of renewable generation across Europe will require not only consideration of where the lowest cost sources of RES-E are located, but also where *demand* is located. Just as efficiency is improved if renewable sources have incentives to "load follow" – generating at times when there is demand, but not at times where there is excess supply – economic efficiency is also improved, all else being equal, if renewable supply is located close to the point of use.

Market mechanisms are well-suited to achieving an efficient balance, reflected in prices, between supply-side costs and demand-side willingness to pay. As discussed above in Section 7.3.1, the specific nature of electricity supply networks – whose function is to bring supply and demand together – can mean that the location-related costs of generation capacity may not be straightforward to calculate or allocate. Nonetheless, greater efficiency can be secured if these costs are reflected, to the extent possible, in the location decisions of RES-E suppliers.

As discussed above in Sections 7.2.2 and 7.2.4, pricing arrangements may not always fully reflect location- (or time-) specific costs and benefits of the electricity output (for example, because of low granularity of electricity tariffs, lack of time-of-use pricing, non-locational network cost allocation, "net-metering", etc.).

RES-E policy designs may be neutral to locational inefficiencies – for example, if there is a uniform EU policy applied to all RES-E technologies. On the other hand, locational inefficiencies could either be corrected or made worse by RES-E policy design decisions. In particular, EU policies currently specify RES-E targets for each Member State. Although these targets have been set taking into account both RES-E resource potential and ability / willingness to pay, they also reflect other factors. Forcing RES-E to be built in countries that have only high-cost RES-E options increases the cost of meeting an overall RES-E target. On the other hand, forcing RES-E to be built only the areas where RES-E costs are lowest could, because of inefficiencies in the electricity markets and decisions about how RES-E is supported, result in higher cost burdens on certain countries.

In essence, setting country-specific targets (or support levels) for RES-E is analogous to setting technology-specific targets (or support levels) – and is therefore subject to the same information asymmetry and uncertainty. In general, setting such targets is inefficient, but can be motivated by distributional considerations.

Current European policy allows countries to trade RES-E obligations / output to meet RES-E targets, which provides a way to improve efficiency while reducing the risk of potentially undesirable distributional outcomes.

The attractions of such a policy are similar to the attractions of emissions trading: in theory, at least, the different abilities and responsibilities of countries / industries / installations can be recognised via the setting of targets (i.e. the "allocation"), while the facilitation of trading makes it possible to provide incentives for efficient investment and operating decisions, irrespective of the initial target-setting.

However, in practice, such trading has been extremely limited in Europe. Norway and Sweden have linked their REC markets, and various countries have discussed potential investments (in both capacity and interconnectors) that would facilitate RES-E obligation trading – but significant trades have not occurred. This suggests that either there are no gains from trading (because the targets have been set so close to the "efficient" levels that there would be no benefit) or that there are significant barriers to trade or market inefficiencies.

Concerns have been expressed that the current set of uncoordinated policies has led to an environment in which there is "subsidy competition" between countries, as they try to design support systems that will attract RES-E investment to meet their targets. This may not affect efficiency (beyond any inefficiencies already inherent in the country-level targets), but it will affect the distribution of costs and benefits, and the profits that accrue to RES-E investors.

It seems likely that a linked REC trading system across the EU, and focused on the private sector rather than governments, would result in higher levels of trading and efficiency gains. However it is difficult to predict ex ante the efficiency implications of trading (relative to individual targets) in a wider electricity market context where efficient locational incentives are not provided.

As suggested above, if locational pricing is not in place, then it may be possible to use individual RES-E targets to deter investment in areas of low demand / costly resource and encourage investment in areas of high demand / inexpensive resource. This could enhance efficiency, but it is likely that welfare gains would be more limited than what could be achieved via fully liberalised market arrangements. On the other hand, in the absence of trading, "mis-setting" of targets can also lead to significant inefficiencies.

Modelling results presented above in scenarios 1-DG and 1-LD confirm that locational decisions about RES-E investment can affect the cost of achieving targets. The overall modelled differences in system costs are not dramatic – but it is likely that this is because the scenarios have been chosen to achieve relatively efficient expected RES-E deployment, as well as because the high DG scenarios assume lower costs for solar PV, for example. That is, the modelling scenarios have been designed to limit the extent to which RES-E is built in the "wrong" places. We have not considered whether this level of cost-efficiency would actually be achieved in practice, given the possible future levels of country-specific (and technology-specific) targets.

Under some circumstances, distributed forms of generation may benefit the system by reducing the need for grid expansions and reinforcements, because generation is closer to the load that it serves. On the other hand, the modelling results also suggest that expansion of distributed generation can also require additional investment in network assets. Moreover, it is important to consider how certain forms of distributed generation, such as rooftop PV, benefit from and use network services. To the extent that owners of rooftop PV impose costs on distribution companies through their consumption of backup services, they should pay for these services – and the amount that they pay, under existing tariff structures, may not accurately reflect this cost, even if, overall, tariff levels are set to ensure cost recovery from all users of grid services.

7.4.3 Priority Access and Balance Responsibility

Part of the rationalisation of RES-E support[101] is promoting technological innovation and efficient investments. But support schemes for RES-E as well as overall market design should also provide incentives for efficient trading and despatch decision of existing RES-E plants. The modelling undertaken for this work also provides some insight into the inefficiencies that can arise when RES-E capacity does not face incentives to reflect the status of the system, because it is not exposed to the electricity price or imbalance charges. In the following, we therefore comment on two further issues: first, priority grid access for RES-E (Section , second, responsibility for balancing cost.

7.4.3.1 Priority Access

The results presented in this report consider the issue of RES-E curtailment in some detail. We note that although at first glance, minimising curtailment may appear to be a desirable objective, in fact, curtailment of RES-E sources may sometimes be economically efficient. Nevertheless, priority despatch for RES-E is included in many regulatory support schemes; under FIT they are a necessary element. When RES-E support was introduced, in many countries priority access was deemed to be indispensable for variable RES-E sources (wind and solar) that could not be scheduled alongside fully controllable conventional energy plants by the system operator.

In the most extreme form of priority access, curtailment of RES-E at times of excess generation (e.g. on sunny weekend days where high production by solar PV coincides with low load) is limited to situations when system stability is endangered. The situation is similar when RES-E generators are only remunerated for the energy actually injected into the system. In this case, operators of RES-E plants will reduce their output only once the costs of selling into the market are larger than the financial support they receive, i.e. in case of negative prices.

In order to study the effects of priority access, we have analysed two sensitivities that are designed to mimic the behaviour of RES-E generators that have limited incentives to consider demand or the impact of their output on the wider system. More specifically, we have considered the following:

- A feed-in tariff support scheme with an unconditional priority access for all RES-E production, represented by a large penalty on curtailment of 750 €/MWh;
- A support scheme with bonus payments or feed-in premiums, with a limited penalty on the curtailment of RES-E, i.e. a penalty of 100 €/MWh on the curtailment of wind and a penalty of 50 €/MWh on the curtailment of solar PV[102].

In both cases, curtailment only occurs in the modelling when RES sources are generating at times when the value of their output is *negative*.

Figure 135 shows that both approaches substantially reduce the level of curtailment, i.e. they allow for the use of more electricity available from RES-E than in case of a pure economic optimisation. More specifically, the additional sensitivities indicate that it may be possible to utilise up to 12.5 TWh of additional energy from RES-E in scenario 1, or approx. 17.5 TWh in case of the sensitivity with a delayed expansion of the European transmission grids. Nevertheless, the left part of Figure 135 also reveals that

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101 Cf. European Commission (2007), "Renewable Energy Road Map. Renewable energies in the 21st century: building a more sustainable future" [COM(2006) 848]

102 The penalties were set based on the deficit in revenues observed in Scenario 1.

these benefits are already reaped in case of a bonus scheme, whereas priority access does not lead to any tangible further reduction. However, the increased use of RES-E does not automatically lead to a similar decrease in OPEX, for instance due to additional cycles of conventional power plants or the replacement of more efficient plants by less efficient units.

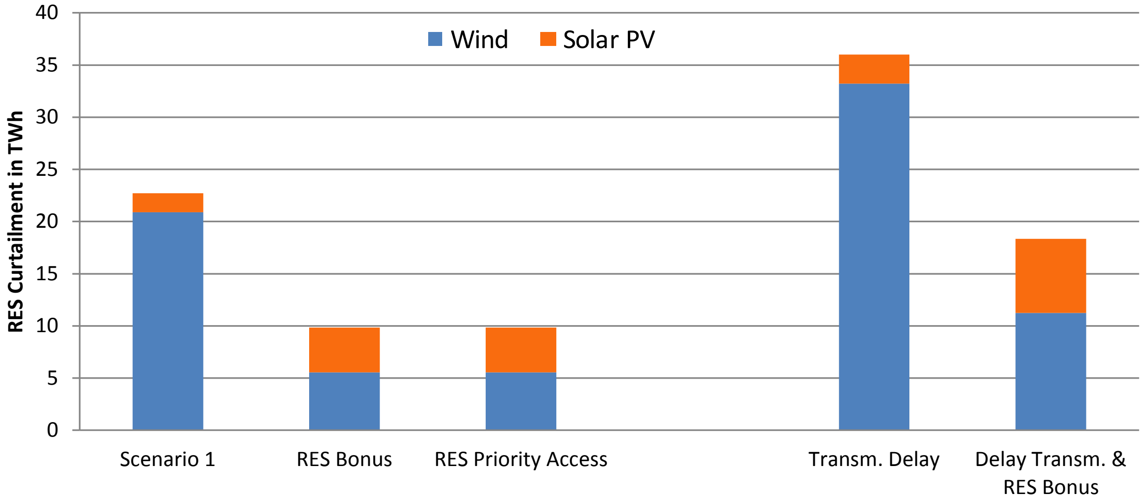

Figure 135 Curtailment of RES-E with support schemes in 2030 (EU-28, in TWh)

Even more importantly, reduced curtailment of RES-E may require additional investments in network and back-up capacity. For the examples defined above, this leads to incremental costs of approx. € 0.5 bn per year at the transmission level alone (see Figure 136). We have not explicitly modelled the corresponding impacts at the distribution level. Nevertheless, the analysis of constrained operation of DG-RES in Section 6.5.3 above (see Figure 133 on p. 150) indicates that guaranteed access for RES-E might add another € 0.5 to 1 bn in costs at the distribution level for scenario 1-DG.

These results confirm that the operating decisions of RES-E capacity can be affected by the way that RES-E policy is designed. Because the investment decision is exogenously imposed, rather than endogenised, it is difficult to use the results to draw firm conclusions about the overall social costs associated with policy provisions such as priority despatch or completely fixed revenues for RES-E – as exposure to or protection from price risk has a significant influence on the decision about whether to invest at all, particularly for individual investors. However, these results highlight that the perceived benefits shown in Figure 135 may actually represent a cost to society as it may be cheaper to curtail the corresponding volumes of RES-E.

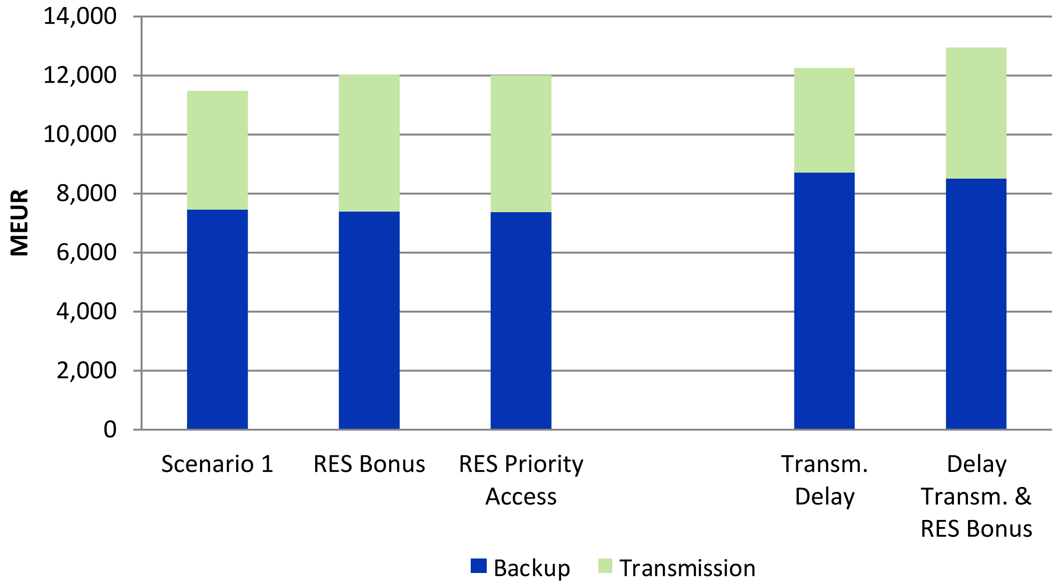

Figure 136 Summary of annualized investment costs in 2030 (EU-28, in MEUR)

In addition, significant changes can be observed for wholesale prices. Average annual wholesale prices decrease (see Figure 137), whilst regional variations increase. As indicated by the strongly increasing spread in the right part of Figure 137 priority access furthermore leads to considerable price volatility. The modelling hence suggests that these Priority Access scenarios appear to lead to a less consistent supply system, in which the difference between "peak" and "off-peak" prices is greater.[103] Depending on the metrics used to define energy security, this may be interpreted to imply a less secure system. Exaggerated off-peak prices created by priority access rules may also distort the energy market, reducing the efficiency of other network and generation investments, as we discuss further in Section 7.2.2.4.

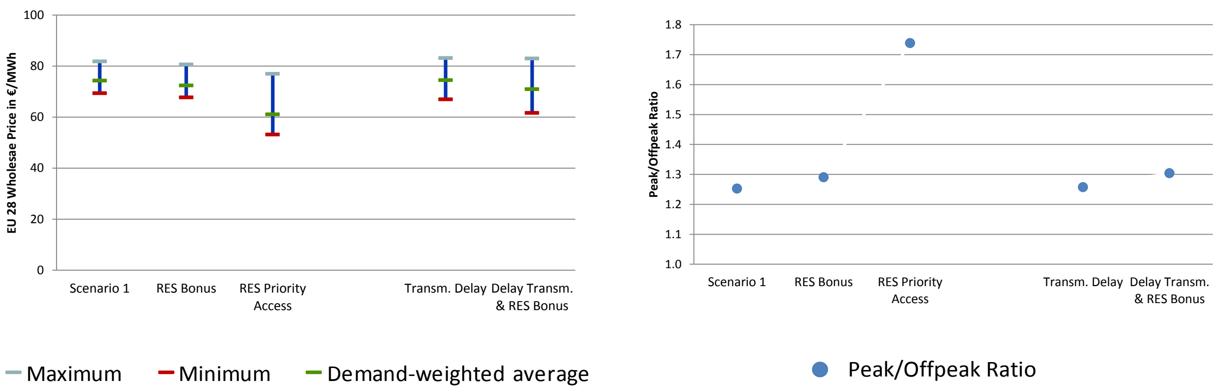

Figure 137 Annual wholesale electricity prices and peak/offpeak ratio in 2030

7.4.3.2 Balance Responsibility

Another aspect of market maturity of RES-E concerns the scope and allocation of the cost of balancing for variable RES-E. When offering their output in the wholesale energy market, operators of RES-E plants will rely on the latest production forecast, which will in turn be based on the latest weather forecast. Any

103 It is not clear, however, that the traditional definitions of "peak" and "off-peak" remain relevant in these scenarios, as the misalignment of demand and supply may occur at times that no longer correspond to traditional chronological patterns.

positive and negative deviations between forecast and actual production will have to be off-set: either by trading these deviations in the intra-day market or through the balancing mechanism. In order to minimise the need for balancing actions and, indirectly, the need for operational reserves, operators of RES-E plants should aim to offset their forecast errors in the intra-day market. However, the incentives to do so do not only depend on the overall design of balancing arrangements but will also be influenced by the way RES-E generators are treated in this context.

The concept of balance responsibility represents a key component of any liberalised energy market that is based on self-scheduling of generators. It implies that each market participant, or an agent nominated by this market participant, assumes the role of a balance responsible party (BRP). The BRP is responsible for minimising the residual deviations between supply and demand of its own portfolio, and has to bear the financial consequences of any remaining imbalances. The concept of balance responsibility hence aims at providing incentives on market participants for taking measures to reduce imbalances caused by deviations between supply and demand, as well as between scheduled and actual generation.

In some countries, balance responsibility of RES-E generators has been transferred to a centralised agent, such as the TSO or a separate entity. In this case, the cost of balancing RES-E are socialised, for instance by means of a surcharge on network or imbalance charges. In other countries, RES-E generators are being treated like any other generator. In these cases, operators of RES-E plant have to bear the full financial consequences of any forecast errors.

Partially or fully transferring imbalance risk to a centralised entity has the advantage that the latter may benefit from reduced imbalances of a portfolio of RES-E plants in comparison with individual plants. Moreover, it is one way of reducing investor costs and hence promoting RES-E investments. However, this option does not create any incentives on RES-E operators on taking efficient operational and investment decisions, which may help to improve predictability and reduce deviations.

Conversely, exposing RES-E plants to imbalance charges may create substantial risks for operators, in particular if they are subject to major forecast errors at shorter time scales, as for instance during the morning and evening "shoulder hours" of solar PV. The resulting imbalance risks reduce the value of energy sales from a RES-E plant and may force operators to offer less than the expected output in the wholesale market. But in turn, balance responsibility also creates strong incentives to minimise residual forecast errors, for instance by improving forecast models or by adjusting trading and scheduling decisions. For example, operators of RES-E plants may decide to initially reduce their sales in the energy market, in order to minimise the risk of deficits in real time. Alternatively, they may try hedge against such risks, for instance by contracting for other sources of flexibility, in order to offset their imbalances in real time.

Experience from some European countries has shown that RES-E generators are able to provide less volatile and more predictable generation schedules if so incentivised by balancing arrangements. In addition, this also promotes participation in the intra-day energy markets and leads to additional opportunities for providers of flexibility, which may thus earn additional revenues in the market.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 Main Drivers of Future Infrastructure Requirements and Technical Barriers

This study has analysed several scenarios with different penetrations of RES-E. In line with the increasing share of renewable energies, all scenarios require major investments into RES-E capacity. By 2030, investments into RES-E and OPEX of conventional generation together account for some 75% of total incremental costs of electricity supply. At the same time, these developments require significant investments into additional infrastructure, including new conventional generation, transmission and distribution. Even when neglecting the costs of RES-E and "normal" conventional plants (e.g. coal plants and CCGTs), this may lead to incremental costs of between € 20bn and € 50bn annually in 2030. On the basis of annualised costs, distribution expansion accounts for the majority of the corresponding costs (approx. 60% to 70%), followed by investments into back up generation, whereas transmission represents less than 15% to 20% of total costs in all scenarios.

These numbers indicate that it is important to understand the main drivers for infrastructure needs, relevant technical barriers as well as possible technical measures that may help reducing infrastructure requirements. In the following, we briefly identify and explain the main drivers for infrastructure needs in each of the three different areas, followed by a brief summary of relevant technical barriers. Thereafter, Section 8.2 summarises the most promising technical measures as identified in Chapter 6 above.

Relation between RES-E and Conventional Generation

The study has shown that different scenarios may require a different volume and structure of conventional generation capacity. The need for conventional generation capacity is primarily driven by the evolution of electricity demand. Conversely, the choice of different RES-E technologies appears to be of secondary importance, although for instance technologies with higher capacity factors (e.g. offshore wind) require less conventional capacity than solar PV. Thirdly, a comparison between a resource- and a load-driven distribution of RES-E has shown that locating renewable generators into geographical proximity of demand may help to reduce infrastructure requirements, including the need for back up capacity.

Based on the findings presented in this report, the study leads to the following conclusions with regards to the ability of RES-E to displace conventional generation and the residual requirement for conventional generators:

- An increasing penetration of RES-E can displace conventional generation capacity that is capable of providing base load, i.e. which mainly serves to supply energy. This effect is primarily driven by capacity factors of RES-E but is not directly related to the technology or source of renewable energy.
- Conversely, the impact of RES-E on the total need for conventional plants, and other types of firm capacity, strongly depends on the type of RES-E. Whilst controllable sources, such as biomass, geothermal energy or hydropower, can effectively contribute to generation adequacy, the impact of variable RES-E remains limited. Even in combination with a large-scale expansion of European transmission grids, variable RES-E have to be largely backed up by conventional capacity with low capital costs (e.g. OCGT). The need for conventional back up capacity depends on the minimum amount of capacity, which variable RES-E can make available at all times, or at least during times of high load. In contrast, the firmness of different RES-E technologies is not equivalent with its capacity

factor, i.e. even variable RES-E generators with a high capacity factor may not be able to contribute to firm capacity substantially.

- Both effects are driven by the type and source of RES-E generation but do not depend on the choice for either centralised or decentralised generation. Ceteris paribus, the need for conventional plants, including back up capacity, is thus independent of the share of DG in RES-E.
- The geographical distribution of RES-E represents an important driver for infrastructure needs. Renewable generation that is located close to demand centres may allow reducing the need for conventional back up capacity, irrespective of the network level to which it is connected.
- Finally, the need for conventional back up capacity is closely related with transmission expansion (see below). Although less transmission expansion may reduce the cost of the network, it may require significant additional back up capacity to be built.

Need for and Drivers of Transmission Expansion

The study also has shown that different scenarios and assumptions may lead to different network structures and a different level of transmission expansion in general. Though transmission expansion may not be absolutely essential, additional transmission greatly facilitates the integration of (variable) RES-E, whereas constrained grid expansion leads to additional challenges and costs. Overall, the following key observations are worth noting:

- Transmission expansion becomes increasingly important as the penetration of RES-E grows. Additional transmission may not be strictly required in a technical sense. However, a reduced level of transmission may either require other infrastructure to be built or result in substantially more curtailment of RES-E generation.
- Transmission investments are mainly driven by differences in the costs of available electricity (energy) at different locations. With regards to RES-E, this particularly implies the following:
  - The need and benefits of transmission are primarily driven by the geographical distribution of RES-E and load. A balanced geographical distribution of RES-E across Europe, or within individual countries, hence creates an important instrument for facilitating the integration of both controllable and variable RES-E.
  - The scope for transmission expansion is also influenced by the capacity factor of different types of RES-E and its correlation with local load. Since transmission represents a cost-effective solution for sharing energy production between different areas, it facilitates the utilisation of electricity production from renewable energies, which might otherwise remain unused (e.g. be curtailed).
- Transmission may also help to share flexibility and firm capacity between different regions. Except for very short distances, however, this benefit will not justify transmission expansion on its own but will rather be a “by product” of transmission capacity that is built to enable the exchange of energy.

Need for and Drivers of Distribution Expansion

As mentioned above, distribution accounts by far for the largest share of additional infrastructure that is required to facilitate the integration of RES-E. Although distribution expansion is partially influenced by the same factors as transmission reinforcements, it is important to account for some specific drivers, such as a much increased importance of load growth and the variability of RES-E as well as the influence of the connection level. The main drivers for the need of distribution expansion can be summarised as follows:

- In many cases, the future need for distribution reinforcements may be driven by load growth in general and an increase of peak load in particular, for instance due to an increasing penetration of heat pumps or electric vehicles. Conversely, an increasing penetration of DG seems to remain of secondary importance in most parts of Europe until 2030, at least in the scenarios considered by this study.
- Nevertheless, high penetrations of DG will generally require an expansion of distribution networks, in order to deal with increasing back flows and/or voltage problems. Nevertheless, a limited share of DG may initially help to avoid or defer distribution investments, especially in case of controllable DG.
- DG-related distribution expansion is mainly driven by the type of RES-E. Controllable DG is less likely to require network reinforcements, or may even allowing avoid or at least deferring them. Conversely, distribution expansion will generally be required to facilitate integration of higher penetrations of variable RES-E. Similarly, the need for distribution expansion strongly depends on the production profile of variable RES-E and its correlation with local load profiles.
- Investment requirements at the distribution level are also strongly influenced by the voltage level at which (variable) RES-E are connected to the distribution network. Similarly, the need for network reinforcements for a given penetration of RES-e will generally be higher in rural areas than in urban areas with higher load density. A harmonised distribution of DG-RES and demand across different voltage levels hence helps to reduce the need for network expansion. However, these savings have to be balanced against the cost of more expensive network connections and /or differences in resource availability.
- In contrast to the transmission level, a substantial share of necessary network reinforcements is caused by voltage problems rather than by a violation of thermal limits. As further discussed below, smart grid technologies and other "low-cost" solutions hence play a potentially much larger role at the distribution level.

Technical barriers for integration of RES-E

As mentioned above, it may be technically possible to integrate an increasing penetration of variable RES-E into the power system even without additional infrastructure being built, provided that it is possible to curtail production from RES-E. Consequently, the ability of European power systems to integrate increasing volumes of variable RES-E is mainly related to economics, whereas it is more difficult to identify clear technical barriers.

Still, the analysis of necessary curtailment has shown that there exist several possible barriers for integration of variable RES-E:

- Lack of adequate network infrastructure (transmission and distribution);
- Inflexible generation and demand; and
- Connection and operating conditions.

Insufficient network infrastructure represents an important barrier for an efficient utilisation of available production from variable RES-E. A lack of transmission or distribution capacity leads to increasing levels of curtailment and may, in the case of insufficient transmission capacity, require additional back up capacity to be built. Although the corresponding effects have not been quantitatively assessed through additional simulations, it is clear that the capability of the power system to integrate additional RES-E may also be constrained by inflexible generation or demand.

These effects are also influenced by the (in-) flexibility of (local) generation and demand. Indeed, curtailment of RES-E may be avoided either decreasing the production of (thermal) power plants that may be required to provide ancillary services, and/or by increasing demand, i.e. by means of demand response. Although we have not assessed this effect quantitatively, it is clear, therefore, that inflexible generation and demand represent a potential barrier for integration of variable RES-E as well.

Apart from these fundamental developments, connection conditions may represent another technical barrier for the integration of RES-E. Apart from requirements on generation technologies, this especially applies to the technical rules governing the point of connection. Allowing variable RES-E to connect to any point in the network without consideration of local conditions may result in an excessive need for network reinforcements and hence lead to substantial additional costs. Conversely, any undue restrictions may create substantial economic barriers for on DG-RES.

As further discussed below, it is therefore important to mitigate corresponding barriers both through the use of promising technical solutions and appropriate regulatory measures.

8.2 Role and Impact of DG on Infrastructure and Costs

In contrast to many other studies, which have analysed future challenges and infrastructure requirements of the European power system to date, this study has paid particular attention to the role of DG and its specific impact on European distribution networks. This assessment has revealed several insights into the role and of DG on infrastructure requirements and the costs of electricity supply. In particular, the analysis in this study has shown that:

- DG does not have any direct impact on need for transmission and back up capacity;
- DG may both cause and avoid distribution expansion, depending on:
    - Type of DG (i.e. controllable resources vs. variable RES-E and correlation with load);
    - Penetration of DG;
    - Vertical distribution (i.e. connection level);
    - Horizontal distribution (proximity to load and transformer stations);
- Need for distribution expansion can be strongly reduced when combined with more flexible demand or decentralised storage.

The simulations carried out in this study do not show any clear advantage for either centralised or decentralised generation when looking at the need and cost of transmission and back up capacity. The costs of transmission may both increase or decrease. Similarly, whilst the need for back up capacity generally increases in the DG scenarios, a closer analysis reveals that these impacts are mainly driven by the type and regional distribution of variable RES-E on a European level rather than the choice between centralised and decentralised generation within a given region.

In contrast, and as would have been expected, the analysis in this study clearly shows that DG may have a significant impact on the need, composition and costs of distribution expansion. Moreover, the analysis shows that DG may both cause and avoid distribution expansion. The corresponding effects are strongly influenced by the type of DG. Generally speaking, controllable resources, such as thermal plants fired by fossil fuels and/or biomass or hydropower, may avoid or at least defer distribution expansion, provided that they can be reliably called upon at times of high load. Conversely, the possible savings from variable DG, like solar PV or small-scale wind turbines, remain highly limited as they cannot guarantee a firm supply of electricity at times of peak load. Even more, in order to successfully integrate higher levels of variable DG, additional distribution capacity is required, mainly due to the limited capacity factor of variable RES-E (in particular solar PV), which requires a lot of capacity to be installed to deliver a given amount of energy. Although the need for distribution expansion also depends on the correlation between the production profile of a given resource and the local load profile, the need for network expansion is mainly driven by the maximum amount of capacity to be transported but not the correlation between average production and consumption.

Besides the type and overall penetration of DG, the need for distribution expansion also depends on the vertical and horizontal distribution of DG. Connecting DG to higher voltage levels allow accommodating a higher absolute penetration of DG but will reduce the benefits of avoided or deferred network expansion, especially in case of controllable DG. In addition, the need for distribution expansion is influenced by the horizontal distribution of DG, i.e. its proximity to load and transformer stations. Hence, the need for distribution expansion can be reduced by installing production capacities closer to demand (e.g. in urban or suburban rather than rural areas), or by locating (variable) DG closer to the transformer at the start of individual feeders.

These considerations indicate that the impact of DG depends on a multitude of different factors. There is no universal relation between the share of DG and the need of distribution expansion, but it depends on the local situation. Consequently and as also reflected by the results of our numerical analysis, similar developments may thus lead to different outcomes under different circumstances. As further discussed below, this principally provides the basis for managing the need for distribution expansion, for instance by influencing the type and local distribution of (variable) DG through adequate regulatory options. Similarly, the potential challenges of integrating large volumes of variable DG may also be mitigated by increasing local flexibility, for instance by means of more flexible demand or decentralised storage. In other words, the benefits of DG will be particularly large when combined with other developments leading to more flexible local demand at the distribution level.

8.3 Possible Technical Solutions

In Chapter 6, we have analysed a number of technical measures and solutions, which may be considered in order to facilitate the integration of RES-E whilst limiting the need for additional infrastructure and reducing overall costs to consumers. The discussion has shown that there exist a multitude of possible options, some of which can be implemented relatively easily at limited costs, whereas other may be more difficult or costly to introduce.

Table 27 lists a number of potential measures, which may help to facilitate the integration of RES-E. For each of these measures, which are explained in more detail in Chapter 6, Table 27 also specifies in which areas they may allow for cost savings, i.e. generation, transmission or distribution. This summary shows that some measures, like demand response or the use of ‘smart grid’ technologies, may lead to savings in several areas. Conversely, our analysis also indicates that the benefits from many other measures can be expected to be largely limited to one particular area. It is also visible that many of these measures may help to reduce the need for back up generation or distribution expansion. In contrast, there appear les options for reducing the need for transmission expansion, which is in line with our earlier conclusion in Section 8.1 that the need for transmission expansion is mainly driven by the regional distribution of different types of variable RES-E across Europe.

Finally, it is worth noting that the measures at the bottom of Table 27 are generally related to larger investments and/or significant improvements of technology. In contrast, we believe that the measures in the upper half of Table 27 can be introduced with limited costs as they are largely based on existing technology and do not require major changes to the current infrastructure.

Table 27 Summary of technical measures that may facilitate the integration of variable RES

Measure	Areas of possible cost reductions		
	Generation	Transmission	Distribution
Ancillary services from RES-E plants	✓		(✓)
Utilisation of demand response	✓	✓	✓
Regional sharing of operating reserves	✓		
Improved RES-E forecasts	✓		
Reactive power from DG-RES			✓
Restricted DG-infeed by solar PV			✓
Improved network monitoring and control		✓	
More flexible conventional plants	✓		
Technology improvements of RES-E	✓	(✓)	(✓)
Pan-European overlay grid		✓	
Innovative transmission technologies		✓	
Use of 'smart grid' technologies	(✓)		✓
Decentralised storage	(✓)		✓

Based on the quantitative analysis in Chapters 4 and 6, it is possible to assess the potential benefits, which many of these measures may bring to a future power system with a high penetration of variable RES-E, including a large share of DG. Figure 138 presents an indicative comparison of the costs and net benefits of the technical solutions listed in Table 27. We note that it has not been possible to investigate the potential impact of every single measure in detail in this study, and that an analysis of the costs of the different measures as beyond the scope of this study. Consequently, we emphasise that the comparison in Figure 138 should be understood as indicative, and that a more detailed investigation of individual aspects may very well reveal further differences that are not shown in Figure 138.

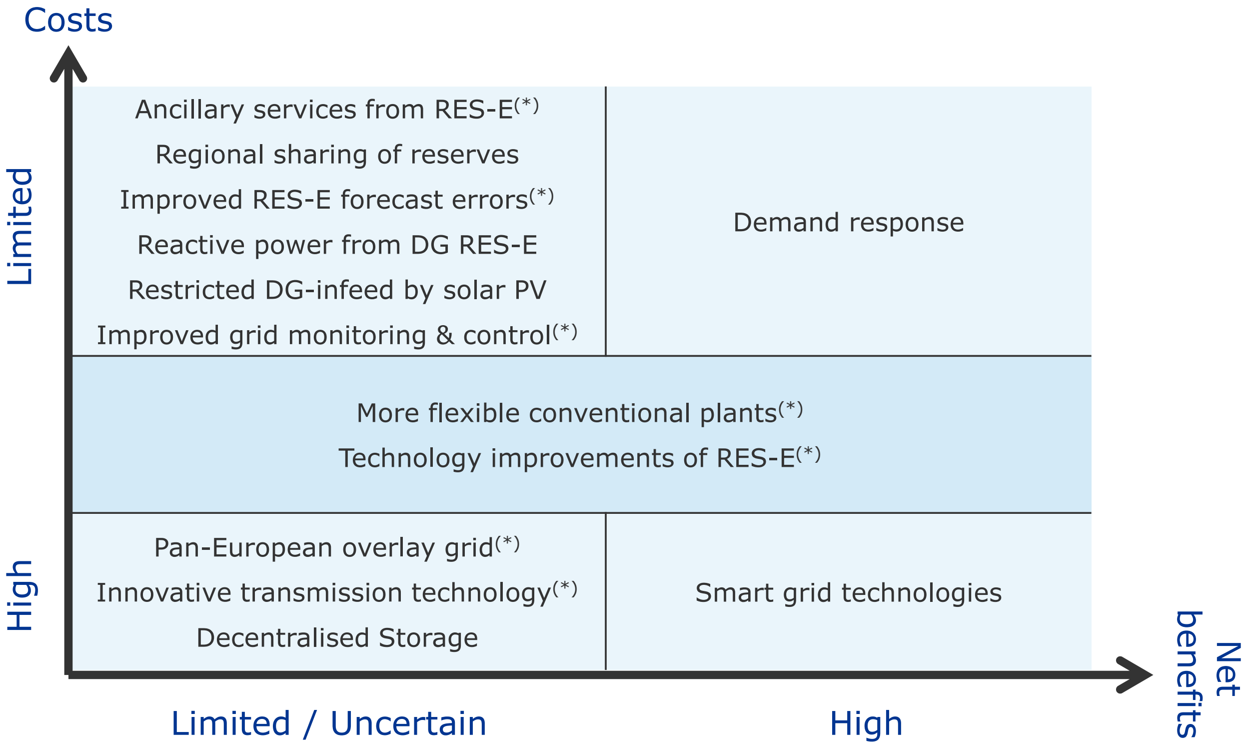

Figure 138 Indicative comparison of costs and net benefits for selected technical solutions
Note: (*) indicates measures for which the potential economic benefits have not been quantitatively estimated in this study, or not a sufficient degree of detail.

Against this background, our analysis has shown that the measures listed on the right of Figure 138 have are principally able to deliver major savings to power systems with a large share of variable RES-E, with annual savings of in excess of € 10 to 20 billion. Conversely, our analysis indicates much smaller savings for the measures on the left of Figure 138, of somewhere between less than € 1 billion and up to € 5 billion annually. In addition, this group includes several measures, for which this study has not delivered a quantitative estimate of the potential economic benefits. The same applies to the two measures in the centre of Figure 138, although we assume that both of them may potentially allow for substantial savings.

Figure 138 suggests the following conclusions with regards to the value and attractiveness of the different measures identified in Table 27 above:

- Demand response seems to represent the most attractive option as it is able to deliver major savings but can be used at limited costs. In particular, demand response can facilitate the integration of DG, i.e. when being provided not only by large but also by smaller and medium-sized consumers. Similarly, additional volumes of DR will be available in situations with an increasing penetration of heat pumps and electric vehicles, helping to mitigate the challenges caused by the additional (peak) load from these applications.
- Secondly, our analysis strongly suggests pursuing the different measures listed on the top left. Although the individual contribution by each of these measures may be limited in many cases, they may lead to substantial savings when used in combination. Moreover, these measures represent ‘no regret’ options that can be implemented at limited costs since they do not require substantial additional infrastructure or major technological developments.

- In a way, the two measures in the centre of Figure 138 can also be considered as potential 'no regret' options, or even as an essential precondition for the large-scale integration of variable RES-E into the European power sector. However, it is difficult to assess the costs and timelines at which such improvements may be realised. Indeed, it seems that these two options rather represent desirable outcomes that should be supported by market design (see below) as well as research & development, but that it may be more difficult to directly control them.
- As indicated by the analysis in Chapter 6.5, smart grid technologies, such as area and in-line voltage control or voltage regulated distribution transformers, may allow for potential savings. But the use of these technologies requires potentially major investments. Moreover, as emphasised in section 8.2, the economic value of these measures strongly depends on the local situation, such as the existing design and state of the distribution network, the type and penetration of variable DG etc. Consequently, the potential benefits of smart grid technologies may need to be carefully weighed against costs in each case, in order to ensure that their deployment delivers true economic benefits to the system.
- Similar considerations apply to the last group on the bottom left of Figure 138. Due to the major investments required, the costs and benefits of these options need to be carefully analysed. For the particular case of decentralised storage, we furthermore emphasise that the potential benefits of this option critically depend on major cost reductions of this technology. Based on the results of this study, it therefore appears uncertain whether decentralised storage will already represent an economically efficient solution by 2030[104], even when assuming a major growth of variable DG.

Despite these cautioning comments, we note that the measures presented in Table 27 and Figure 138 should not be considered as a set of mutually exclusive alternatives. Instead, they rather represent a menu of suitable measures, which can and indeed should be used in combination.

Based on the identification of possible solutions, a key question for the purpose of this study is what is required in order to implement different solutions, or how their future use may be promoted? In preparation of the discussion of possible changes to regulation and market design in Section 8.5 below, Table 28, therefore, shows a separate view of the measures identified above. More specifically, Table 28 differentiates between measures and/or changes, which require:

- Technological advances, for instance in the areas of equipment design, operational practices or forecasting, monitoring and control;
- Improvements of the current and envisaged market design, including interactions between different stakeholders in the electricity market and/or remuneration;
- Development of the regulation of network operators;
- Major investments into new assets, including generation, transmission, distribution or storage and, to a lesser degree, monitoring, communication and control.

[104] Our analysis does not generally support the use of electricity storage in the time horizon until 2030, mainly due to high capital cost, conversion losses and the type and regional distribution of RES-E (largely wind power) in most of the scenarios considered. Still, decentralised storage (in combination with solar PV) may potentially become a promising solution under certain circumstances and assuming a major decline in investment costs.

Table 28 Preconditions for implentation of potential technical measures

Measure	Changes / Improvements in area of Technology / Operations	Market design	Regulation	Substantial investments required
Ancillary services from RES-E plants		✓		
Utilisation of demand response		✓	(✓)	
Regional sharing of operating reserves	(✓)	✓		
Improved RES-E forecasts	✓	(✓)		
Reactive power from DG-RES		✓		
Restricted DG-infeed by solar PV		✓		
Improved network monitoring and control	(✓)		(✓)	(✓)
More flexible conventional plants	✓	(✓)		✓
Technology improvements of RES-E	✓	(✓)		✓
Pan-European overlay grid	✓		(✓)	✓
Innovative transmission technologies	✓		✓	✓
Use of 'smart grid' technologies	(✓)		✓	✓
Decentralised storage	(✓)		(✓)	✓

In line with our previous comments, Table 28 shows that most of the measures in the first group can principally be implemented by adjusting and further developing the design of European electricity markets. In this context, it is worth noting that many of these measures are implicitly covered by or are at least fully compatible with the Target Model for the electricity market. Although we do acknowledge that implementation of many of these measures would involve considerable complexity, they do not require any fundamental changes but can principally be implemented within the currently evolving legislative and regulatory framework at a European and national level. Moreover, they can largely be implemented with existing technologies and at limited costs, such that we do not foresee any fundamental barriers to their deployment.

In contrast, many of the measures listed in the lower half of Table 28 require further technological advances as well as major investments into new assets. Apart from uncertainty on the evolution of future technology and costs, these measures require access to sufficient funds in both the competitive and regulated sectors, i.e. for operators of generation and storage assets as well as transmission and distribution networks, respectively. As discussed in Chapter 7 this requires sufficient incentives to invest and may, therefore, require further refinements to regulation and market design (see Section 8.5).

8.4 Market Impacts and Barriers for Investments

In addition to an in-depth analysis of future infrastructure requirements, this study has also analysed the resulting impacts on electricity markets as well as the operation and profitability of conventional and renewable generation technologies.

The simulations show that the fuel mix and average wholesale price levels may both change significantly over time, reflecting the underlying changes in the generation structure as well as each scenario's assumptions on the development of fuel and CO_2 prices. From the perspective of the electricity market and market participants, therefore, it seems more important to note the following developments:

- In line with an increasing penetration of variable RES-E, some scenarios are characterised by an increasing volatility of wholesale market prices. This development furthermore is strongly correlated with the degree of transmission expansion; whereas scenarios with optimised network reinforcements lead to converging regional prices and limited volatility, a lack of or limited transmission expansion may result in major regional disparities and extreme levels of volatility in some areas.

- Depending on the mix of RES-E generation technologies, the profile of wholesale market prices may change substantially. In line with recent developments in Central Western Europe, the simulations show that especially a growing penetration of solar PV depresses traditional peak / off-peak ratios but may lead to short but more pronounced daily peaks during shoulders hours in the morning and evening.
- As the penetration of renewable power generation grows, the role of conventional power generation capacity changes. Running fewer operating hours, operation and revenues of conventional plants will be less predictable, and they will become more dependent on peak energy prices to earn the margins required to cover their fixed operating and investment costs. In addition, increasing price volatility and short-lived price spikes will require more flexible generation, which is able to react more quickly to changing market conditions.
- Due to the variable production by RES-E, European power systems will principally be in need of increasing volumes of ancillary services. This principally creates additional income for flexible generators that earn less from wholesale markets but can provide ancillary services to the system. When assuming that variable RES-E are incentivised to provide ancillary services and that balancing services are shared by TSOs on a regional basis, however, the additional income to conventional generators may remain limited. In addition, an increasing contribution from other sources of flexibility that were not traditionally used in the past, such as demand response, may further reduce prices and generators' revenues in the ancillary services markets.

As mentioned in Section 8.1 all scenarios will require considerable infrastructure to be built and maintained. This study has therefore specifically analysed the profitability of different generation technologies, in order to assess whether the scenarios considered and current market arrangements may lead to potential barriers for investments into new generation infrastructure. In addition, Section 8.5 comments on other aspects related to the regulation of electricity networks.

With regards to the profitability of different generation technologies and incentives to invest into new plants, the results of the study lead to the following observations and conclusions:

- Increasing reliance on short-lived price spikes might increase the risk profile of generation investments and the financing costs they face. However, increasing price volatility may also reward more flexible generation, which is able to react more quickly to changing market conditions.
- The profitability analysis of different generation technologies indicates that existing generators will generally be able to recover their fixed O&M costs throughout the whole modelling range. Nevertheless, periods of temporary over-capacity, caused by the rapid increase of RES-E, may force some older plants to retire before the end of their economic lifetime.
- As mentioned in Section 8.2, the value of additional electricity storage seems to remain limited in the time horizon until the year 2030. Consequently, it is not surprising to see that market revenues do not generally justify investments into new electricity storage.
- Although the modelling framework does not allow drawing strong conclusions on the extent to which new conventional generation technologies are able to recover their fixed O&M and construction costs, the results do show that necessary investments into new conventional plants may be profitable.
- While is it true that some inefficiencies in energy markets may undermine the efficiency of investments taken by participants in the energy market, these inefficiencies have not been modelled

within our framework, which fundamentally assumes a well-functioning energy market. Therefore, any suggestion from the modelling results that prices do not remunerate investment in new capacity should not lead to the conclusion that the energy market will not remunerate investment in the generation capacity required to integrate RES-E into the EU power system efficiently.

- The analysis carried out in this study does suggest that the profitability of renewable technologies improves towards 2030. Still, the overall level of power prices will remain too low to remunerate investments in most RES-E technologies. This suggests that subsidies will continue to be required to support the scale of RES-E development assumed in this study, in particular in the case of offshore wind and solar PV.

8.5 Possible Options and Requirements in Regulation and Market Design

As discussed in Chapter 7 efficient integration of renewables can be best achieved by implementing power market designs, network charging arrangements and renewable support schemes that promote effective competition and economically efficient outcomes. In principle, the aim of promoting economically efficient outcomes is best achieved through well-functioning, competitive markets, in which participants are exposed to the marginal costs they impose on the system, and receive the marginal benefit they provide to the system through revenues or cost savings. Similarly, network charges should send efficient locational signals to network users, whilst regulation of network companies must ensure that an efficient level of investment takes place in distribution, transmission and interconnection to accommodate renewables expansion efficiently. Finally, support schemes for RES-E support should not only promote technological innovation and efficient investments but also provide incentives for efficient trading and despatch decision of existing RES-E plants.

Against this general background, Chapter 7 has discussed different options that can be taken in this respect with regards to the design of efficient energy markets, electricity network regulations, and renewable electricity support policies. Many of these options mentioned reflect ongoing developments on the way towards implementation of the target model for the electricity market, such as regional integration of wholesale and ancillary services markets. Similarly, other measures have already been the subject of extensive discussions, like the possible need and benefits of a capacity mechanism or the challenges around the remuneration of network investments that are providing economic benefits to multiple countries or stakeholders in an interconnected system.

For the purpose of this study, we therefore focus on a limited number of selected measures that are specifically related to the technical challenges and solutions identified in Sections 8.1 to 8.3 above; see Table 29. The first two options are specifically aimed at improving the way, in which flexibility is priced in and allocated between the energy and ancillary services markets. The third and fourth items are both related to network regulation and the objective of providing incentives for efficient investment decisions by network operators. The last two options finally are mainly directed at RES-E generators, although locational signals may equally serve to promote efficient investment and operational decisions by conventional generation and load.

Table 29 Selected measures in regulation and market design

Measure	Market Design	Network Regulation	RES-E Support
Reduced duration of trading intervals	✓		
Close-to-real time markets for ancillary services	✓		
Changes to network planning standards		✓	
Encourage innovative ("smart") network technologies		✓	
Use of locational network charges		✓	
Provide incentives for market-supportive behaviour and reduction of imbalances			✓

Similar to the discussion of potential technical solutions in Section 8.3, not all of these measures will be equally effective in mitigating the challenges of integrating RES-E, and they will also differ in terms of the costs they may impose on consumers. In order to put the different measures into perspective, it thus seems useful to consider the contribution of different cost items to total incremental costs of electricity supply (compare Section 4.6.2):

- Incremental costs of electricity supply are clearly dominated by CAPEX for new RES-E plants, followed by OPEX of conventional plants, i.e. costs for fuel and CO_2 emissions;
- Apart from CAPEX for new conventional plants, the costs of distribution expansion represent another major cost item; and
- Investments into additional back-up capacity and transmission expansion, though being substantial, do only represent a small fraction of total costs.

Based on these considerations, Figure 139 presents an indicative comparison of the costs and benefits of the changes to regulation and market design identified in Table 29 above.

The two measures on the top right can principally be expected to support major savings at limited costs. As mentioned above, revised network planning standards at reaching an optimal trade-off between constraint and investment costs for connection of variable RES. If implemented properly, this may help to avoid unnecessary investments and/or undue restrictions to new connections especially in distribution networks, noting that distribution expansion accounts for a considerable proportion of total incremental costs. Similarly, the removal of preferential rights of variable RES-E during daily system and market operation may lead to major savings. Overall, these two measures thus appear as particularly valuable.

We have argued above (see Section 8.3) that the use of "smart" network technologies represents a potentially very promising technical solution, which may lead to major savings. However, the design of truly efficient regulatory regimes for this purpose is highly complex and still under discussion. In addition, this option also bears a risk of significant additional costs when not properly implemented, i.e. in the form of rewarding unnecessary investments. Despite its potential merits, this measure may, therefore, have to be considered with some caution in comparison with the first two measures.

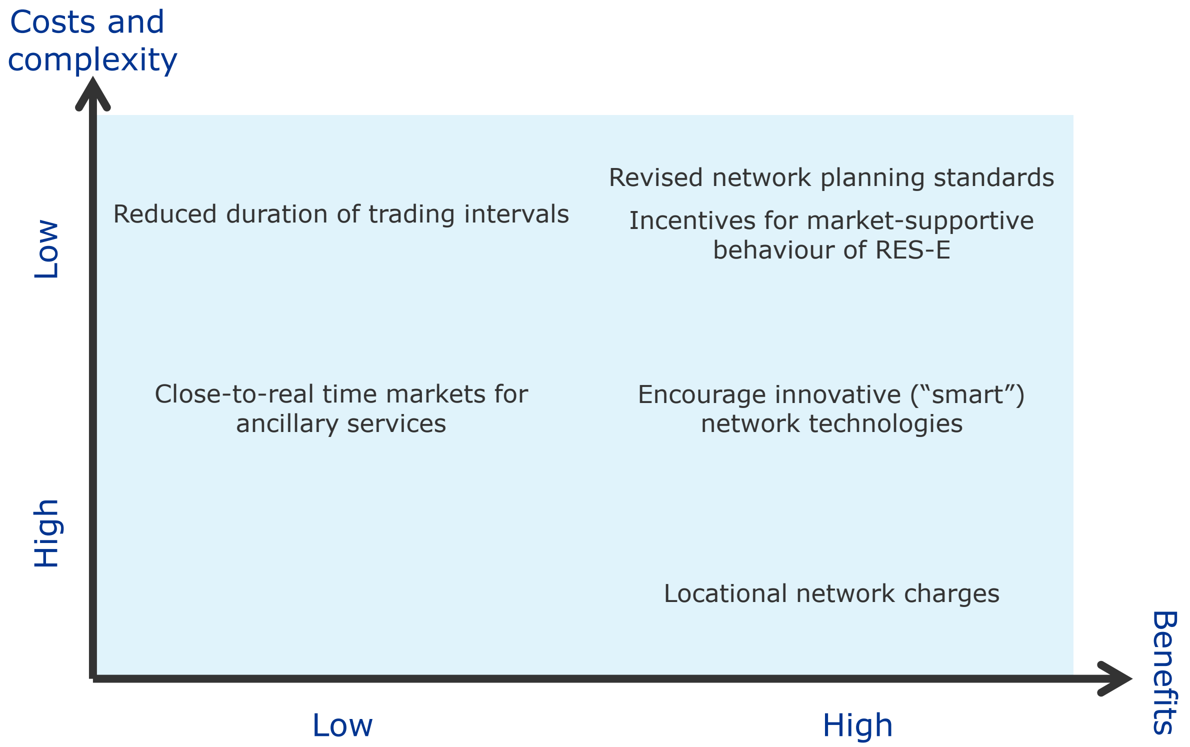

Figure 139 Indicative comparison of costs and benefits of selected changes to regulation and market design

The benefits of shorter trading intervals or close-to-real-time markets for ancillary services can be expected to remain more limited since they will mainly allow for a limited reduction of OPEX and, potentially, some back up capacity. Nevertheless, reducing the length of trading intervals represents a measure that can be implemented quite easily such that it may deserve further study. Conversely, the introduction of close-to-real-time markets for ancillary services (see section 7.2.4), where the allocation of ancillary services to different service providers is not decided upon on the day ahead (or even before) but shortly before real time, may become fairly complex, especially when being considered at a regional or even European level. Moreover, we expect that a major part of the potential savings can already be reaped by full implementation of the target model, i.e. a liquid pan-European intraday market, such that the incremental benefits of this measure may remain limited.

Finally, an extended use of locational network charges may incentivise a balanced distribution of variable RES-E (and conventional plants) across different regions as well as on a more scale within a distribution network, i.e. both in terms of horizontal and vertical location. This may allow reducing the need for network expansion, especially at the distribution level. Similar to the promotion of "smart" network technologies, however, the design of truly cost-reflective locational charges at the distribution level may become highly complex.

8.6 Selected Recommendations

The modelling results in this study have shown that future infrastructure requirements as well as the overall costs of electricity supply are strongly influenced by the choice and regional distribution of different types of variable RES as well as the design and planning of individual assets and the overall electricity supply system. Our analysis suggests, therefore, that technical and regulatory measures, as well as wider efforts in the areas of research and development, should aim at the following objectives, in order to facilitate the integration of variable RES-E and reduce the need for additional infrastructure:

- Incentivise parallel **expansion of RES-E and network infrastructures**, which aims at a balanced regional distribution and technology mix of RES-E;
- Promote a **balanced distribution of (variable) DG** across different network levels and between different types of distribution networks (e.g. urban vs. rural areas);
- **Support technology improvements of RES-E plants**, which lead to increased capacity factors and decreasing variability;
- Facilitate use of demand response; and
- Stimulate the use of innovative transmission and "smart grid" technologies.

In Sections 8.3 and 8.5 we have considered a range of technical solutions and regulatory measures, which may considered in order to support these overarching goals. In addition, we have assessed the individual measures with regards to their effectiveness, costs and complexity of implementation. Based on this discussion, Table 30 provides a list of selected recommendations with regards to technical design and operations, on the one hand, and regulation and market design, on the other hand.

Table 30 List of selected recommendations

	Technical Design and Operations	Regulation and Market Design
Priority measures	• Use of demand response • Provision of ancillary services by RES-E • Regional sharing of operating reserves • Provision of voltage control by variable DG • Limited infeed by solar PV (% of capacity installed) • Improved network monitoring and control • Selective use of smart grid technologies	• Implement target model • Revised network planning standards • Incentives for market-supportive behaviour of RES-E • Encourage innovative ("smart") network technologies
Additional measures to be considered	• Use of innovative transmission technology • Pan-European overlay grid • Use of decentralised storage	• Locational network charges • Reduced duration of trading intervals • Close-to-real time markets for ancillary services
Other areas to be supported (R&D)	• Reduced forecast errors (RES-E) • Technology improvements of RES-E, conventional plants, storage and innovative network technology	

More specifically, we have grouped our recommendations into three different categories. First of all, Table 30 identifies a number of **priority measures**, which can be expected to both effective and efficient, i.e. which can be implemented with limited costs and complexity and which can either be expected to deliver major economic benefits, or otherwise represent "no-regret" options, including the selective use of smart grid technologies. Based on our analysis, these priority measures should clearly be supported by future European policy and regulations. We emphasise that full implementation of the target model for the electricity market clearly is among the most important steps as it implicitly covers or is at least fully compatible with many of the other priority measures listed in Table 30. Among others, this also applies to the promotion of demand response, which our study has revealed as one of the most powerful technical measures.

Secondly, Table 30 also list a number of **additional measures to be considered**. These measures may potentially allow for significant savings. However, their true benefits either appear uncertain or may only apply in certain areas or situations, like the construction of a European overlay grid or the use of decentralised storage. Likewise, the cost and complexity of changes to regulation and market design may outweigh the potential benefits of these measures when not being implemented properly. In contrast to the first category, application of these measures should be subject to further study, potentially on a case by case basis, in order to ensure that they really lead to net economic benefits.

Finally, Table 30 includes a summary of **other areas deserving further support**. This group includes technical improvements for instance in terms of equipment design or forecasting accuracy. Our analysis suggests that corresponding improvements may also facilitate the integration of variable RES-E and reduce costs, but such improvements cannot be directly controlled and directed. To a certain extent, one may reasonably expect that such technological advances will be indirectly driven by the electricity market, i.e. assuming that the measures mentioned above will reward flexibility, or more generally the capability of supporting the system. From a policy perspective, these areas may nevertheless deserve additional support, for instance in the form of support to future research and development.

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