Europe's future secure and sustainable electricity infrastructure

e-Highway2050 project results

November 2015

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Foreword

After 40 months of intense work, the project will be delivering its results by the end of 2015. On November the 3rd and 4th, the main findings of the project are presented during the conference, offering a forum to discuss the future implementation.

The present booklet summarises the key findings of the project. For more details, please refer to the deliverables available in the website www.e-highway2050.eu or contact: rte-e-highway2050@rte-france.com

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Gérald Sanchis
e-Highway2050 coordinator
rte-e-highway2050@rte-france.com

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Disclaimer

Various scenarios have been studied under the project. The purpose is to cover a wide range of possibilities, not to identify a preferential one as only the costs and benefits of the transmission grid have been assessed. The cost of the complete power system should include also generation, demand side management and efficiency measures, storage and distribution network. This is out of the scope of the e-Highway2050 project.

The reinforcements of the transmission grid identified by the project are related to significant assumptions. Much efforts were dedicated to the relevance of these assumptions. However, as for any prospective study, some of them could for sure be discussed. In that perspective, the project is willing to make them as transparent as possible and encourage stakeholders to consider them carefully. Especially, the grid architectures defined by the project should not be re-used in documents or presentations without a reminder to the related assumptions.

e-Highway2050 key findings

- New methodologies for the development of the European transmission grid have been developed, enabling to:
  - Address long term horizons,
  - Cover the whole Europe,
  - Cope with the European low carbon objectives, translated at national, and local levels, while building global grid architectures

- An invariant set of transmission requirements has been identified in consistency, and in continuity with the Ten-Year Network Development Plan conducted by ENTSO-E. Their benefits for the European system, resulting from the optimal use of energy sources, largely exceed their costs.

- The proposed architectures integrate the present pan-European transmission grid, without needing a new separate 'layer' within this existing transmission network.

Executive summary

The European Commission, together with the member states, has defined clear targets for the decarbonisation of the European economy from 2020 up to 2050.

These low carbon trends for the European economy have a direct impact on the design and upgrade of all the European energy infrastructures, and especially on the electricity transmission network due to its critical role for the pan-European power system.

The European Network of Transmission System Operators for Electricity (ENTSO-E) addresses the developments of the pan-European electricity transmission network until 2030 in the Ten-Year Network Development Plan (TYNDP). Starting with the same network configuration for 2030, the e-Highway2050 research and innovation project goes until 2050: it deals with the transition paths for the whole power system, with a focus on the transmission network, to support the European Union in reaching a low carbon economy by 2050.

Novel network planning methodologies have therefore been developed to address such long-term horizons and cover all the continent. They have been used extensively to identify key network developments for Europe. The five very contrasted energy scenarios provide an envelope of the possible future evolution of the European power system while meeting the 2050 low carbon economy orientation.

The methodology relies on extensive numerical simulations of a model of the pan-European transmission network (made of approximately 100 regional and interconnected clusters): these simulations support an estimation of the benefits of grid expansion, thanks to a modelling of both generation and grid constraints. The robustness is guaranteed by a Monte-Carlo approach covering probabilistically various climatic years.

The simulations show that the 2030 network is not sufficient to face the 2050 energy scenarios. Indeed, during significant periods, grid congestions would prevent some available generation to reach the load. Especially, huge volumes of renewable energy sources (RES) would be curtailed and compensated by expensive thermal generation emitting CO_2.

To tackle these issues, different architectures of the transmission grid have been developed and compared to assess their techno-economic efficiency.

The results of the studies exhibit the following trends:

- An invariant set of transmission requirements has been found: major "North – South" corridors appear in all scenarios with several reinforcements that connect the North of the pan-European electricity system (North Sea, Scandinavia, UK, Ireland), and southern countries (Spain and Italy), to the central continental area (northern Germany, Poland, Netherlands, Belgium and France);

- The network extension rate is driven by the increase of generation capacities, especially renewable energy sources;

- The proposed architectures could be integrated in the present grid, without introducing a separated 'layer' of transmission grid.

The costs of investment in grid expansion depend on the scenarios. They lie between 100 and 400 billion €. However, the study demonstrates that the benefit for the European economy, resulting from an optimal use of energy sources, would largely exceed these costs in all cases. Indeed, up to 500 TWh of RES curtailment and 200 mega tons of CO_2 emissions would be avoided annually.

To successfully realize and operate those future transmission grids, key challenges have to be overcome. The project has highlighted some of them in the fields of technology, operation and governance.

1 Introduction

1.1 The Climate and Energy Union policy: preparing a low carbon economy

On March 27th 2013, the Green Paper[1] published by the European Commission (EC) framed an upgraded policy environment within which Europe ought to design its whole energy system from 2020 up to the middle of the twenty-first century (2050). Such a long-term perspective had already been laid out in 2011,[2] and then continued through the Energy Roadmap 2050[3] and the Transport White Paper.[4] Moreover, each of these key policy papers had witnessed a parent European Parliament Resolution,[5] aimed at converging on a "low carbon" vision for the European economy by 2050.

An intermediate 2030 framework was then proposed, refined and finalised by the EC and the Member States (MS) in January 2014, assuming that:

- The EU28 is making significant progress towards meeting its existing climate and energy intermediate targets for 2020;
- The 2050 perspectives are still plausible in terms of reducing greenhouse gas emissions by 80–95 % below 1990 levels by 2050.

Since October 2014 there has been a renewed integrated climate and energy policy framework available in Europe to reach a set of 2030 targets. It involves a clear regulatory framework for investors and proposes a more coordinated approach among Member States: this is the Energy Union strategy. This renewed policy framework aims at strengthening the plausibility of the 2030 targets as agreed by the EU leaders. It puts forward five mutually-reinforcing and closely intertwined dimensions:

> Energy security, solidarity and trust;

> A fully integrated European energy market;

> Energy efficiency contributing to moderation of demand;

> Decarbonising the economy;

> Research, innovation and competitiveness.

These dimensions support the three pillars of energy security, sustainability and competitiveness.

1.2 Impacts of the Climate and Energy Union policy on the European transmission grid

The 2030 targets and 2050 long term goals have a direct impact on European energy infrastructures, and more specifically on the pan-European electrical power system. This is directly reflected in the 10 % interconnection target adopted by the Council in October 2014 and presented by the European Commission in February 2015[6]. The Ten-Year Network Development Plan (TYNDP) prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) addresses the development of the pan-European electricity transmission network from now on until 2030.

But what about longer term horizons and the transition paths to support the European Union in reaching a low carbon economy by 2050?

This is the question addressed by the e-Highway2050 project.

This research project, supported by the European Commission under the Seventh Framework Programme, began in September 2012 and lasted for forty months. It was carried out by a large consortium of TSOs, industrial associations, academics, consultants and one NGO.

e-Highway2050 partners

TSOs

Industry

Research institutes

Experts

1.3 The e-Highway2050 project overview

The main results of the e-Highway2050 project are summarised in the present report.

The project had two overarching goals:

- to develop novel planning methodologies of the pan-European electricity transmission network, able to address very long-term horizons;
- to implement the prototype methodology in order to provide a first version of an expansion plan for the pan-European electricity transmission network, going from 2030 (the time horizon of the TYNDP) up to 2050, thus in line with the European energy policy pillars in view of decarbonising the European economy.

This report summarises the following key results:

- The five scenarios to reach long term EU decarbonisation orientations which have been created to frame the whole research and development project (Section 2);
- The critical issues for the transmission grid under these scenarios identified thanks to advanced numerical simulations (Section 3);
- The major "electricity highways"[7] which have been identified to support any of the above scenarios when deployed at pan-European level (Section 4);
- The key technological, regulatory, governance and operational challenges raised (Section 5).

Finally, outlook is presented in Section 6.

Additional work and more details are available in the deliverables provided by the project (see the full list at the end of this report, and on the project's web site).

2 The scenarios

2.1 Some contrasted decarbonised scenarios for 2050

The scenarios presented hereafter are the outcome of a sorting process implemented to select extreme scenarios regarding their impact on the transmission grid. They aim to explore a wide scope of plausible and predictable challenges to be faced by the power system. These challenges are driven by changes in generation, demand, energy storage and level of power exchanges. The e-Highway2050 scenarios are neither predictions nor forecasts about the future: the project consortium does not consider any of them to represent the future, nor does it assume any to be more likely than the others.

The five challenging scenarios resulting from this filtering process are summarised in Table 1, going from a low to maximum RES generation contribution.

Each scenario covers different backgrounds in terms of:

- Economy (GDP, population growth, fuel costs);
- Technology (maturity of carbon capture storage (CCS));
- Policies (incentives towards RES, energy efficiency, national/European energy independency);
- Social behaviour (nuclear acceptance, preference towards decentralised generation).

These various contexts result in significantly different assumptions for generation, electricity demand, storage, and power exchanges. The major differences between the five scenarios are presented qualitatively in Figure 1.

See deliverable D 1.2 for more details

The share of Renewable Energy Sources in the annual European generation ranges from 40% to 100%. Wind generation is significantly high in the scenarios *Large-scale RES* and *100% RES* at levels of 40–50% of the generation mix. Solar generation plays a major role in the scenarios *100% RES* and *Small & local* with about 25% of the total generation mix. Nuclear generation ranges from 19 to 25% of the generation mix in three of the five scenarios *(Large-scale RES*, *Big & market* and *Fossil & nuclear)*. Indeed, nuclear helps achieving the 2050 EU decarbonisation orientations. The 100% RES scenario is nuclear generation free. Fossil energy sources remain significantly high in the scenarios *Big & market* and *Fossil & nuclear* with 18% and 33% of the generation mix, respectively, since for these scenarios, the Carbon Capture Storage (CCS) technology is assumed to be mature. The share of fossil generation in the other scenarios stands below 5%.

Note : The generation mix refer here to the proportion of each energy source in the annual generation. As seen in the figure 2, the yearly demand changes from one scenario to the other.

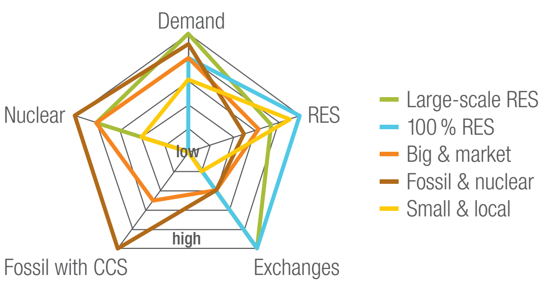
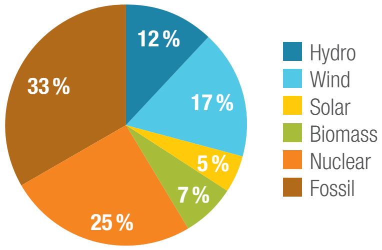


Figure 1: Major differences between the scenarios

Scenario description | **Annual generation mix at European level**

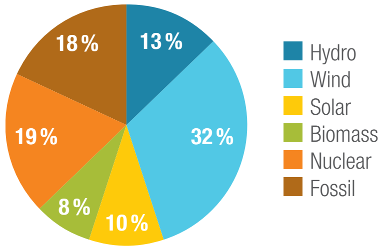
Fossil & nuclear

In this scenario, decarbonisation is achieved mainly through **nuclear and carbon capture storage**. RES plays a less significant role and centralised projects are preferred. GDP growth is high. Electrification of transport and heating is significant and energy efficiency is low.



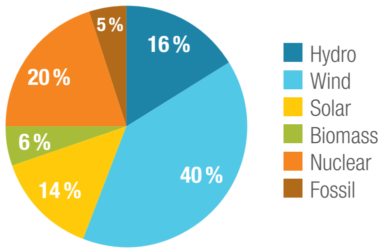
Big & market

In this scenario, the electricity sector is assumed to be **market-driven**. A preference is thus given to centralised projects (renewable and non-renewable) and no source of energy is excluded. **Carbon Capture Storage** is assumed to be mature. GDP growth is high. Electrification of transport and heating is significant but energy efficiency is limited.



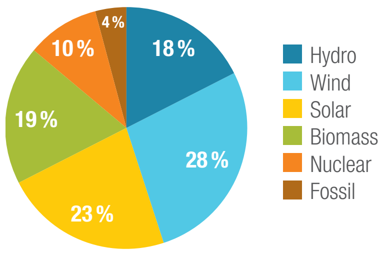
Large-scale RES

The scenario focuses on the deployment of **Large-scale Renewable Energy Sources** such as projects in the North Sea and North Africa. GDP growth is high and electrification of transport and heating is very significant. The public attitude is passive resulting in low energy efficiency and limited demand-side management. Thus, the **electricity demand is very high**.



Small & local

The *Small & local* scenario focuses on local solutions dealing with **de-centralised generation**. GDP and population growth are low. Electrification of transport and heating is limited but energy efficiency is significant, resulting in a **low electricity demand**.



100 % RES

This scenario relies only on **Renewable Energy Sources**, thus nuclear and fossil energy generation are excluded. High GDP, high electrification and high energy efficiency are assumed. **Storage technologies and demand side management** are widespread.

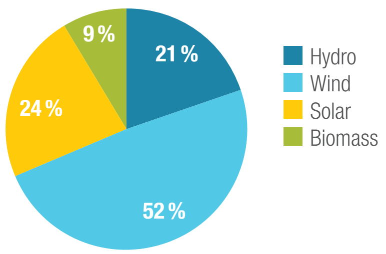


Table 1: The five challenging scenarios of e-Highway2050: short scenario description (left) and presentation of the corresponding European mix (right).

2.2 Generation, demand and storage assumptions in the scenarios

The annual electricity demand is depicted in the Figure 2, for all of the 33 European countries considered[8] and for each scenario. The assessment involves some of the scenario criteria, i. e. GDP and population growth, the use of electricity for heating, industry and transportation and energy efficiency measures. As a result, the European electricity demand varies significantly for each of the scenarios. The scenario *Small & local* has the smallest total volume (3200TWh), which is close to the 2013 levels (3277 TWh). By contrast, the demand in the scenario *Large-scale RES* (5200 TWh) is 60 % more than the levels measured in 2013. The three other scenarios lie in-between such extreme values. The evolution of the minimal and maximal loads follow the same trends: the highest peak load – 926 GW – is encountered in the scenario Large Scale RES whereas the smallest – 532 GW – occurs in *Small & local* and is similar to 2013.

For each scenario, generation capacities are defined in Europe to meet the demand, consistent with each of the scenario backgrounds. The geographical dimensions retained for the study involved one hundred "clusters" covering the whole Europe and some neighbouring countries (see Figure 7). Indeed, due to the uncertainties of such a long-term horizon and the complexity of addressing the whole continent, more detailed descriptions – like the substation level – are neither attainable nor needed for the present work.

The main goal of the approach is to ensure an overall consistency, meaning European targets translated into local generation portfolios, while taking into account parameters like:

- The 2020 national renewable action plans;
- Wind and solar potentials in the clusters (including a maximum acceptable land cover);
- Wind and solar average capacity factors in the clusters;
- Population development;
- National policies towards nuclear;
- The hydraulic potential.

The RES capacities are located preferably in the most profitable clusters. However, a criterion of national energy autonomy is also taken into account for each scenario. For instance, in the scenario *Small & local*, no country supplies more than 10 % of its electricity demand using imports. By contrast, in the scenarios *Large-scale RES* and *100 % RES*, some countries import nearly 60% of their electricity needs.

Thermal generation is also defined with a European perspective. Simulations are performed to assess the appropriate number of power plants necessary to ensure adequacy (assuming infinite network capacities). Thus, over capacity for generation units in Europe is avoided.

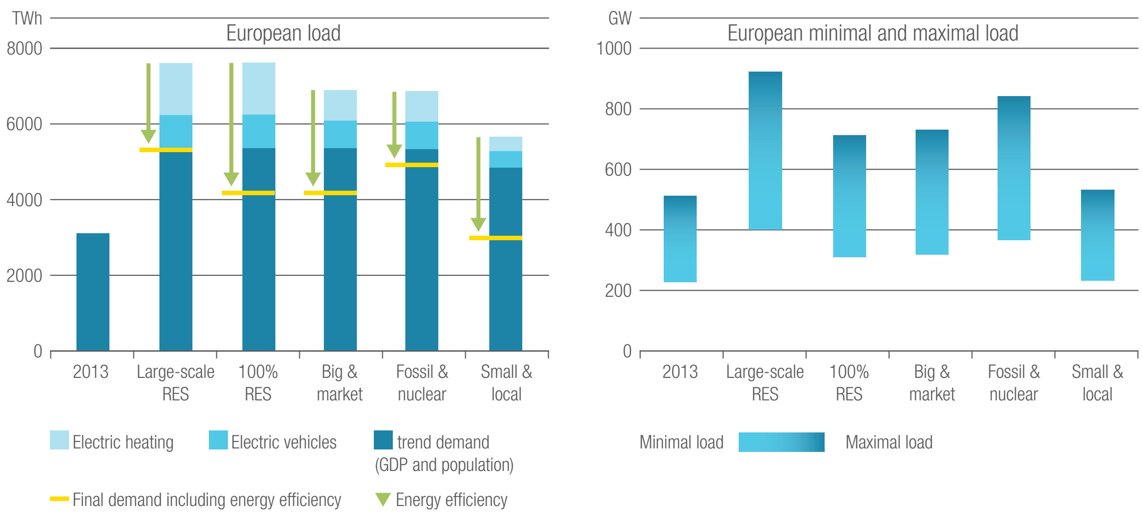


Figure 2: European annual, minimal and maximal demands for the five e-Highway2050 scenarios

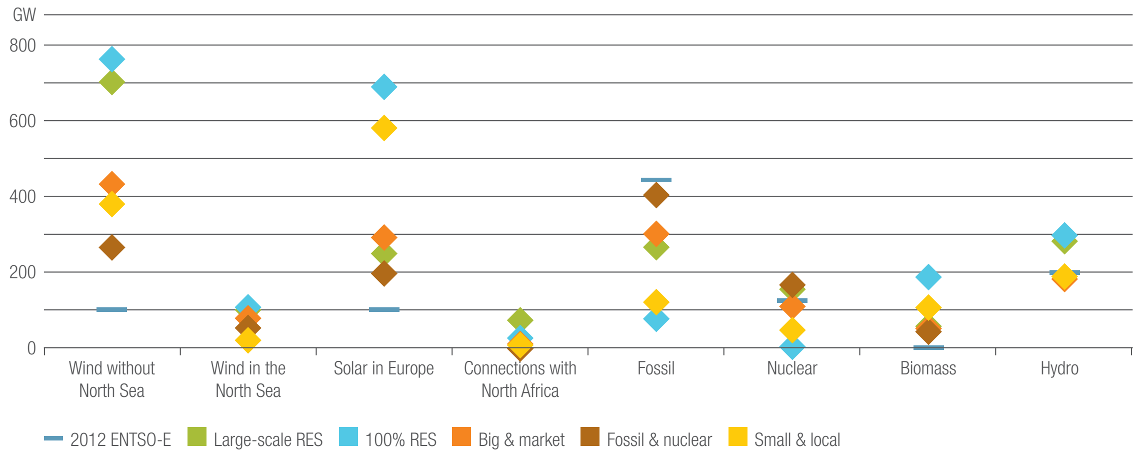


Figure 3: European installed capacities per technology in the five scenarios at 2050 (compared to 2012).

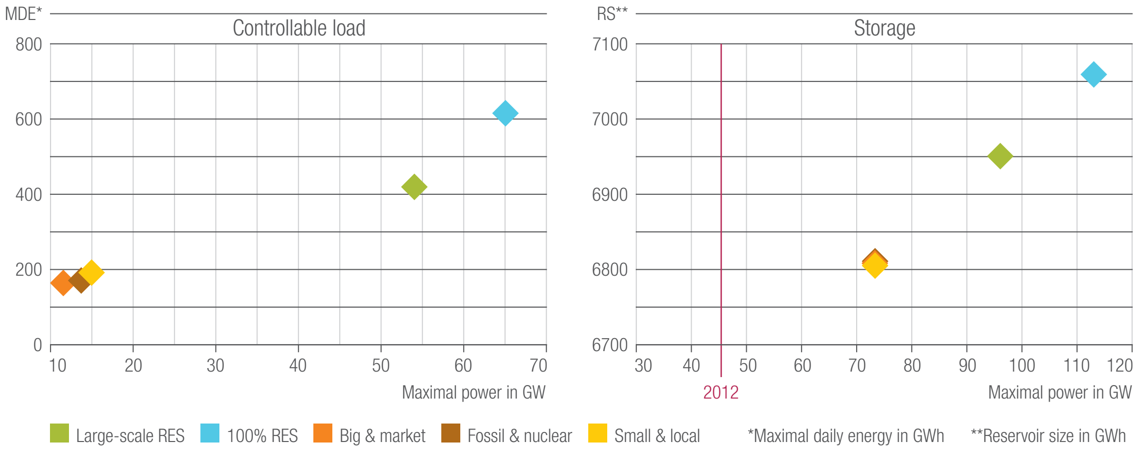


Figure 4: European demand side management assumptions

Figure 5: European storage assumptions

The realisation of such top-down scenarios would require a very high level of coordination within Europe, thus differing significantly from national independent plans.

For each scenario, Figure 3 depicts the 2050 European installed capacities per technology with a reminder of the situation in 2012.

Wind generation capacity ranges from 260 GW to 760 GW plus from 15 GW to 115 GW in the North Sea. For solar generation, capacities range from 190 to 690 GW in Europe. Solar generation in North Africa is very high in the scenario *Large-scale RES*, covering up to 7% of the European demand with a solar installed capacity of 116 GW. In the *100% RES* scenario, solar from the North african area covers 3% of the European demand and less than 1% for the other scenarios. The nuclear capacity increases compared to 2012 in the scenarios *Fossil & nuclear* and *Large-scale RES* – up to 169 GW and 157 GW, respectively. It decreases in the other scenarios. Biomass-based electricity generation, being a dispatchable RES source, reaches significant levels in the scenarios with high RES penetration. It reaches almost 200 GW in the scenario *100% RES*. Noteworthy, in Figure 3, some fossils plants are displayed in the scenario *100% RES*. It actually corresponds to plants that are necessary for adequacy; they are referred to here as “fossil” but other solutions, like more biomass/storage, or DSM measures, could also be imagined. However, as discussed in part 5.4, their profitability might be a critical issue as they serve only a few hours per year.

With the high shares of renewable energy, the development of storage and demand side management is expected in the future. Ambitious assumptions are thus taken into account in the five scenarios as depicted in Figure 4 and Figure 5, Demand Side Management is modelled as a shiftable load within the day. Electricity storage localisation and characteristics are based on typical Pumped Storage Plants.

See deliverable D 2.1 for more details on the methodology and results

2.3 Generation trajectories from today to 2050

The TYNDP 2016 has defined four "visions" to address the 2030 horizon. To assess the trajectory of the power system from 2030 to 2050, a corresponding 2030 vision is identified for each of the five 2050 scenarios consistent with the TYNDP2016 visions: it is considered as the most likely antecedent. Five 2040 scenarios are then defined by interpolating between the 2030 datasets of the TYNDP 2016 and the e-Highway2050 scenarios.

Figure 6 displays the trajectories for three of the five scenarios. All trajectories are characterised by a large increase in the total installed capacity in Europe. This is mainly due to the high share of renewable: more renewable capacity is needed to produce as much energy as thermal generation. The three scenarios presented here lead to the following conclusions:

- Fossil generation decreases significantly, especially coal generation which emits a lot of CO_2;
- Nuclear remains constant after 2030 in the *Big & market* scenario, but decreases in the others. It is even null by 2050 in the *100 % RES* scenario;
- Hydro increases significantly in the *100 % RES* scenario;
- Between 2013 and 2030, the TYNDP 2016 visions 1 and 2 exhibit an average increase in solar capacity by 4 GW/year in Europe, while vision 4 shows 10 GW/year. From 2030 to 2050, the increase rate in the *Big & market* scenario is roughly the same, i. e. 7 GW/year. Yet, the *100 % RES* and *Small & local* scenarios face a drastic acceleration with an installation of more than 21 GW/year;
- Between 2013 and 2030, the TYNDP 2016 visions 1 and 2 show an average increase of wind capacity by 7 GW/year in Europe, while vision 4 shows 16 GW/year. From 2030 to 2050, the increase rate in the *Small & local* scenario is constant when compared with the rate between 2013 and 2050, i. e. 7 GW/year. Yet, for the *Big & market* and *100 % RES* scenarios, the rates of increase are almost doubled, thus reaching 14 GW/year and 25 GW/year, respectively.

See deliverables D 4.3 and D 4.4 for more details

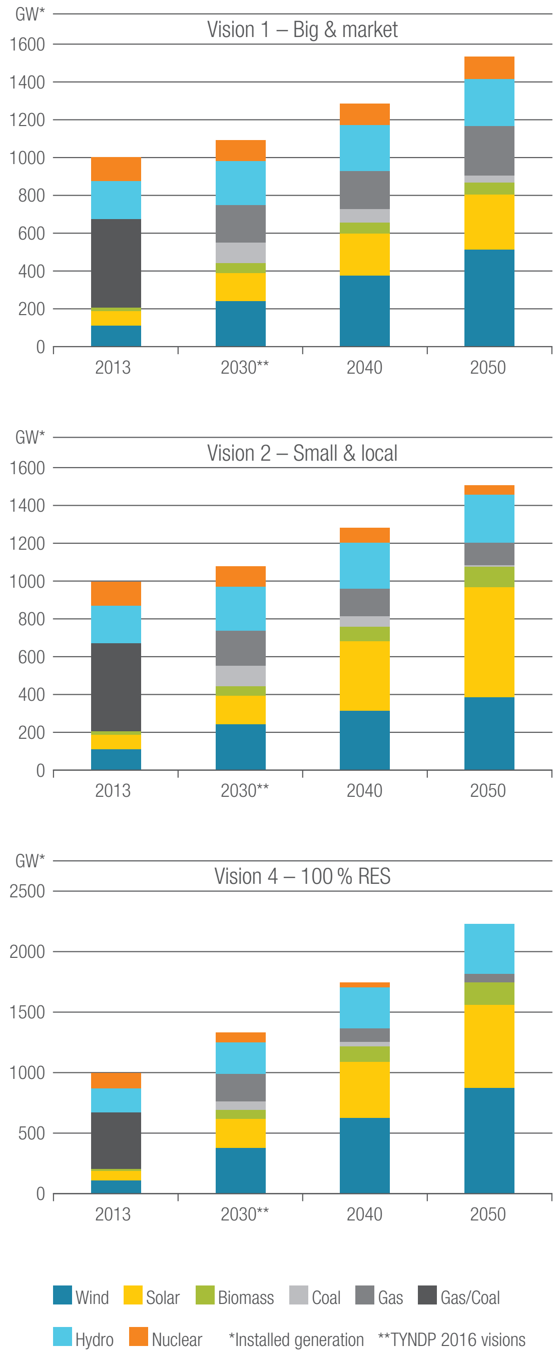


Figure 6: Trajectories of the European installed generation per technology from 2013 to 2050 for three e-Highway2050 scenarios

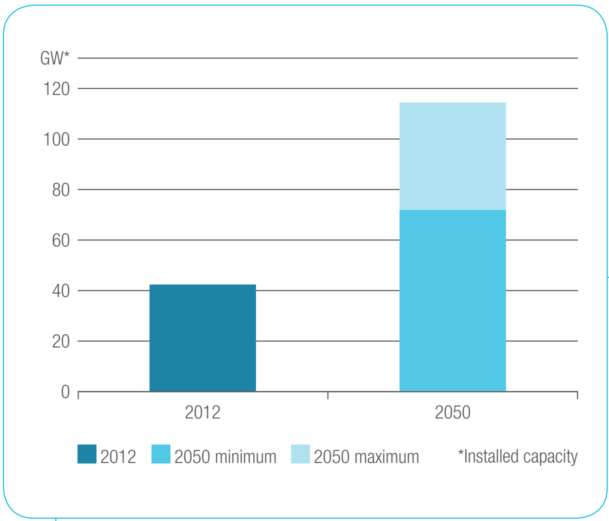


Figure 8: Storage capacities: The additional storage capacities assumed by the project concern only pump-storage technology.

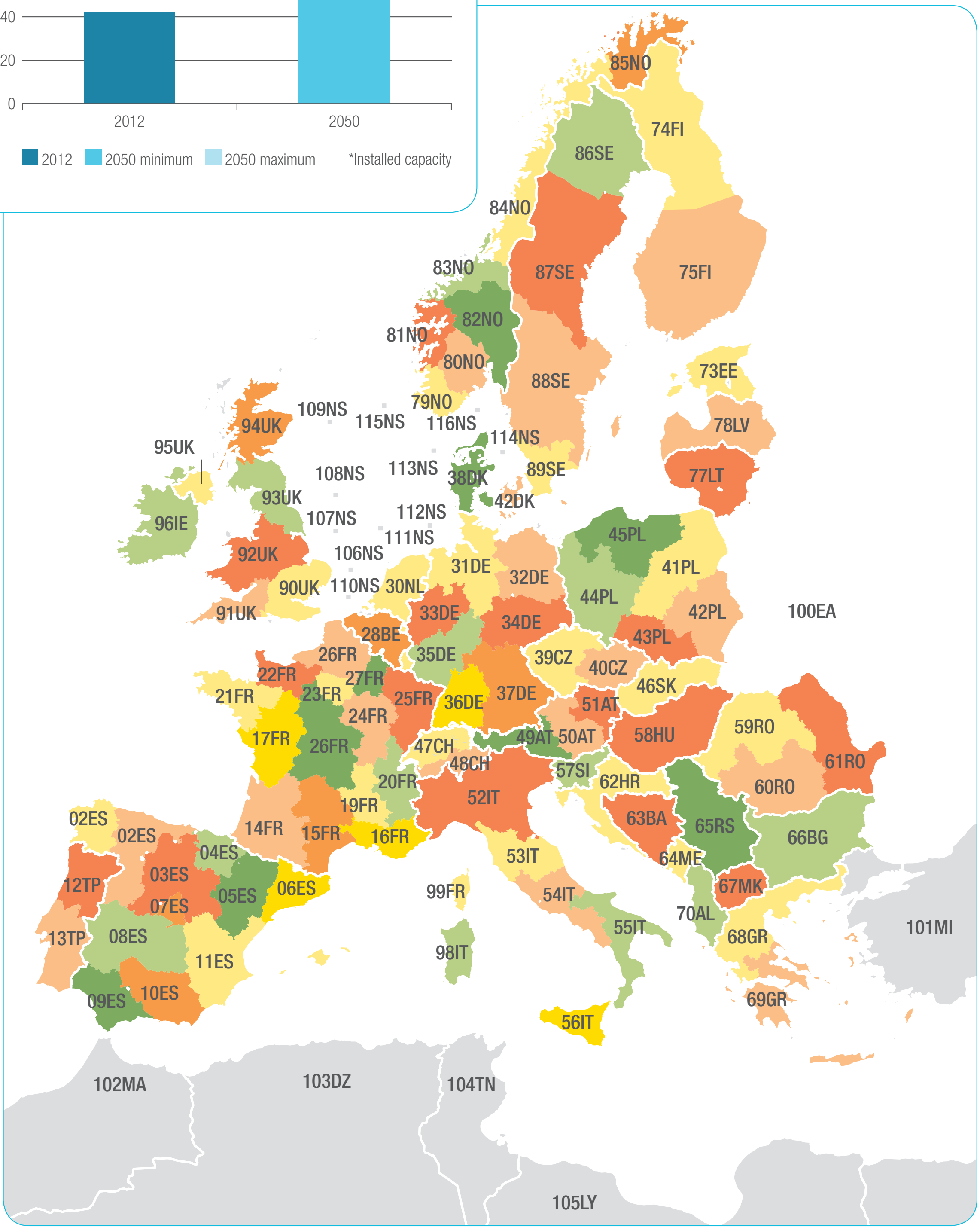


Figure 7: Model with 100 clusters: For the study, the European power system is represented via a zonal model with 100 clusters. Demand and installed capacities for each generation technology have been defined per cluster, and for each scenario. © EuroGeographics for the administrative boundaries

3 The potential grid bottlenecks by 2050

The first step of the analysis is to assess, based upon the generation capacities and the demand foreseen by 2050 in the different scenarios, whether the 2030 transmission grid could be appropriate without any new investments or where congestions might occur. To do so, an equivalent grid model is implemented allowing to perform "system simulations" in order to pinpoint the impacts of the grid limitations. The possibility to implement non-grid solutions is then briefly discussed

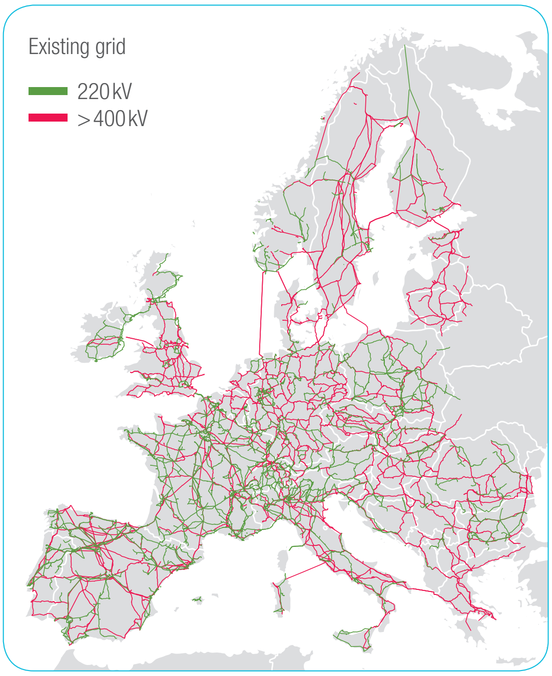
3.1 Initial conditions: the starting grid

The scope of the project covers the period 2030–2050, thus the starting grid, which represents the initial conditions for the transmission grid, is set with the following assumptions:

- the transmission network existing today will still be in operation in 2050, i.e. the existing overhead lines and cable links will have the same topology and characteristics in 2050, even if they have been refurbished;
- the transmission network developments for 2030, foreseen by the TYNDP 2014,[9] which include, for example, major North-South HVDC corridors in Germany (see Figure 9) and some interconnections with North Africa (depending on the scenario), will all be completed.

Based on a detailed model of this transmission network (made of more than 8000 nodes), an equivalent grid model of one hundred clusters is computed to best match the flows occurring on the real grid. For each line of this simplified model, an equivalent impedance and a Grid Transfer Capacity (GTC) is estimated. This equivalent model provides the grid initial conditions, i.e. the starting grid, for the simulations. The detailed model and the starting grid are shown in Figure 9. As can be seen on the right-side of the graph below, the starting grid considered is already well-developed, especially in continental Europe. It is already a major step toward the electricity highways.

See deliverable D2.2 for more details



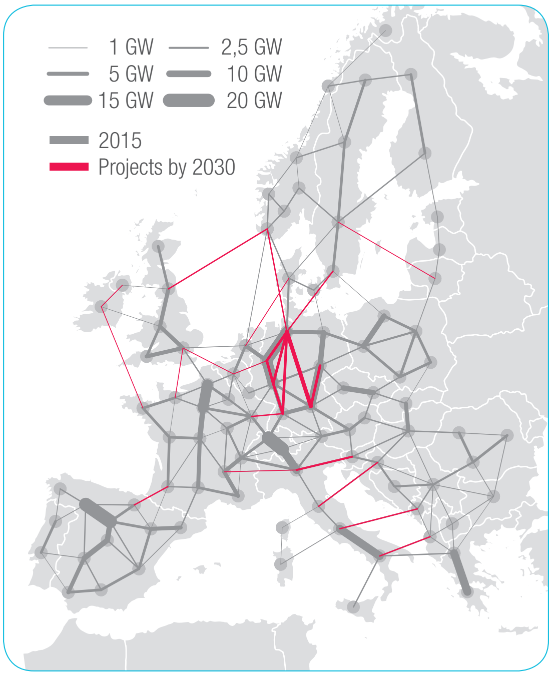


Figure 9: Starting grid of the e-Highway2050 project. Existing grid (left) and equivalent model of the 2030 grid (right, the grey lines represent the existing lines and the red ones represent the projects to be realised by 2030 at the point in time of starting the simulations).

3.2 System simulations

An innovative approach is applied to provide a robust numerical model of the behaviour of the whole European power system. The starting grid, as well as the description of the demand, storage and generation portfolios are embedded in the numerical "system simulations" performed with the software *Antares*[10]. These simulations optimise the dispatch of generation in terms of cost for each hour of the year, taking into account the starting grid topology and characteristics (impedances and Grid Transfer Capacities). Thus, this optimisation problem identifies the cheapest generation to cover the demand while keeping flows on the network within their limits. (optimal power flow) The operating costs of the pan-European power system can be estimated for the starting grid and for any modified grid architecture. This is at the core of the cost-benefit analysis described in part 4.2.

Given the high share of RES, the simulation of only one climatic year cannot ensure robust results. To tackle this issue, probabilistic simulations of 99 possible years are performed using a Monte-Carlo approach. All results presented in this report are the minimum, maximum or average values over these Monte-Carlo years

3.3 The consequences of the bottlenecks

If the grid as foreseen for 2030 is combined to the 2050 scenarios, the simulations show that the power system will face major issues.

First, during some periods, load cannot be completely supplied. These situations occur in clusters where generation is not sufficient and bottlenecks in the starting grid prevent available generation in other clusters to serve this load. The significance of such events strongly depends on the regions and on the scenarios. The Figure 10 below shows, for the least critical scenario (*Small & local*), the annual number of hours with some unsupplied demand[11] in the different countries. For example, in this scenario, load shedding occurs in France more than 800 hours per year.

On the other hand, a significant amount of renewable generation cannot reach load centres due to grid congestions and have to be curtailed. This does not systematically result in load shedding since local thermal generation can sometimes be used instead. However, these local generations have significant fuel costs and lead to CO_2 emissions. That is why curtailed renewable energy represents both economic and environmental drawbacks. Figure 10 displays, for each country, the percentage of renewable generation curtailed per year in the same scenario (*Small & local*). For instance, in this scenario, 22 % of the offshore North Sea wind generation has to be curtailed.

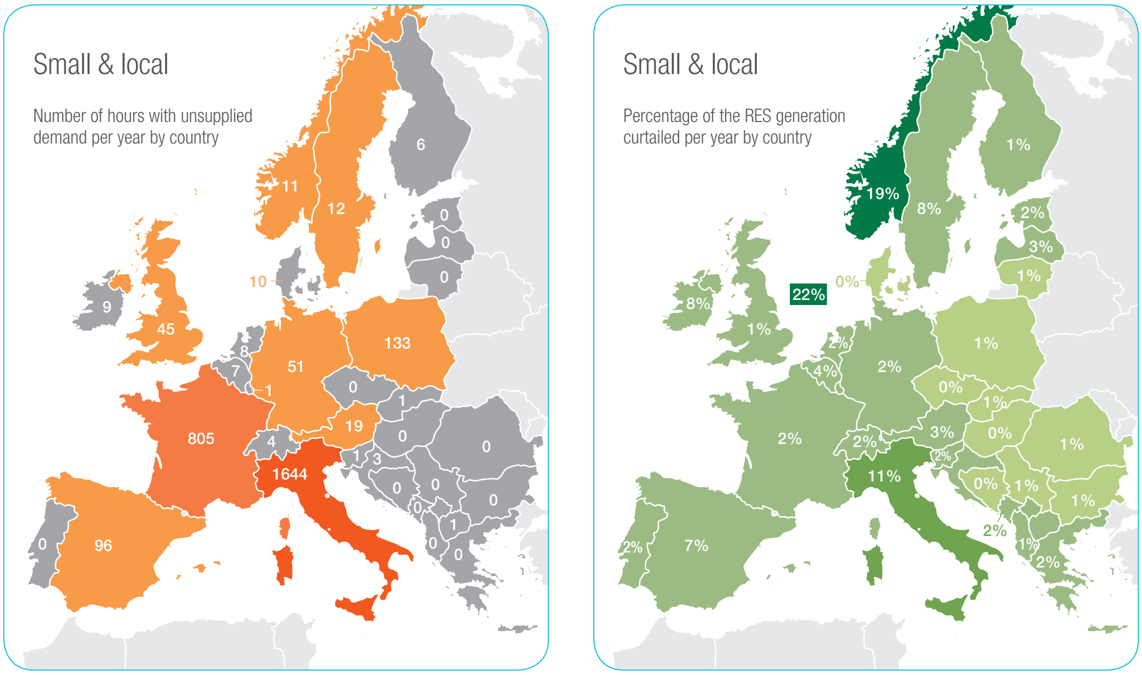


Figure 10: Left: Number of hours with unsupplied demand per year by country in *Small & local*. Right: Percentage of the RES generation curtailed per year by country in *Small & local*.

3.4 Potential solutions excluding transmission grid development

Several options to cope with the above transmission network bottlenecks are available: some are discussed hereafter based on indicative qualitative analyses but could be further investigated. Such solutions could indeed be alternatives to the transmission grid development (which is the scope of the e-Highway2050 project and is addressed in-depth in Section 4). Let us mention generation, electricity storage or Demand Side Management (DSM).

Invest in more thermal generation capacities where needed

Load shedding can be avoided by installing more fossil-fuel peak power plants near these loads. Based on the results of the numerical simulations for the whole Europe, the capacity of such additional generation would be at least 60 GW in the less severe scenario (*Small & local*) and at least 140 GW in the most critical one (*100 % RES*). Their respective contribution to yearly generation would then be 5 and 50 TWh. The cost of such additional generation would range between 5 and 25 billion Euros per year[12]. Despite these significantly high costs, more thermal generation would be unable to solve the problem of RES spillage and would increase the resulting CO_2 emissions.

Invest in more short-term electricity storage or Demand Side Management

According to the simulations, in some southern countries, an excess of PV generation occurs regularly during spring and summertime. In the evening, thermal generation has to start to meet demand. Local daily electricity storage could be used in such cases to shift PV generation from midday to the evening. For instance, in the case of Spain in the *Small & local* scenario (see Figure 11 below), the amount of daily energy to store would be around 70 GWh in the summer. This could be implemented, for instance, with 10 million batteries of 7 kWh. Assuming a cost of 2 000 Euros per battery, the investment cost would reach 20 billion Euros, for Spain alone. A significant decrease in cost is necessary to make this solution viable when compared with peaking units or grid development.

In addition, when assessing the results from the simulations, daily storage does not appear to be a suitable solution for countries like Germany or France, neither for southern countries in winter. Indeed, in those cases, no significant excess of RES generation occurs during the day as the significant amount of storage and DSM already assumed are sufficient to cover possible PV surplus. (cf. Spain in January in Figure 11).

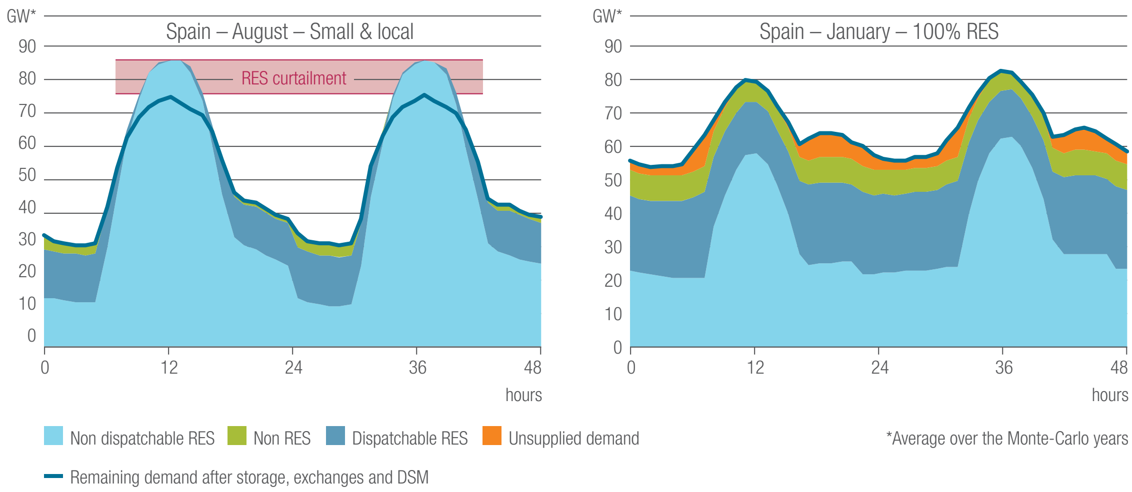


Figure 11: A typical load profile over 48 hours for Spain: summertime in the *Small & local* scenario, wintertime for the 100 % RES

Invest in more PV generation and storage

Load shedding occurs almost exclusively in the evening in winter. At that time, more PV generation cannot help or should be combined with electricity storage. Considering the cost of storage and PV generation and also the low PV load factor in winter, the cost of this solution is extremely high. For instance, in the *100% RES* scenario, more than 70 GWh of load are not supplied in the winter evenings in Spain (Figure 11). With a PV load factor around 11 % in winter, an increase of at least 30 GW[13] of PV would be necessary for an investment cost of 42 b€ (assuming 1.4 b€/GW) plus 20 b€ of batteries for Spain only. This additional PV generation would be almost completely curtailed in summer or even more storage should be considered.

Invest in more wind generation

In the case of Spain in the *100% RES* scenario (Figure 11), load shedding occurs in winter for an average of 4 GW. Delivering an average 4 GW would require the development of at least 17 GW of wind power.[14] In this scenario, the installed wind capacity in Spain is already 70 GW out of a potential estimated at 80 GW.[15] Thus installing 17 GW of extra wind power capacity seems unrealistic, at least for this scenario. Moreover, assuming an investment cost of 1 b€/GW, it would cost at least 17 billion Euros for Spain alone. In general, the RES capacities in the e-Highway2050 scenarios are already extremely ambitious, and the extra costs to further increase them would be high.

e-Highway2050 focuses on transmission solutions

Additional studies could be performed to assess the techno-economic efficiency of the solutions proposed above and also other options like for instance Power to Gas. A combination of all the solutions might even lead to more promising answers to the system challenges. The e-Highway2050 project aims at only assessing grid solutions in detail. Transmission grid development is expected to be a very efficient solution since it combines the following assets:

- It can transport renewable energy from areas where it is not needed to load centres. This is typically the case for the North Sea offshore wind parks or for RES generation in Scandinavia;
- It enables areas having very different load and generation patterns to support each other. For instance, southern countries can export PV generation during the day to northern Europe and during the night northern Europe can export wind generation to southern consumption areas;
- It can smooth the RES fluctuations between European countries. For instance, France and Germany may not encounter high winds during the same periods.

4 The power grid infrastructure suited for a low carbon economy by 2050

Thanks to the electric system simulations described above, several transmission grid architectures can be compared to assess their techno-economic profitability.

The purpose of the grid development process is to find an optimal solution between two extreme options:

- No further reinforcements are implemented beyond 2030. The grid investments are then minimal: yet, the generation operating costs of the power system are high since grid congestion can prevent from using the cheapest generation units (see the simulation results shown in Section 3.3).

- Infinite capacities are built between all the clusters of the starting grid (the so-called “copper plate” assumption). The grid investment is then virtually infinite, but the operating costs of the power system are minimal since the cheapest generation units can always be used whatever their location is.

For each scenario, a methodology is thus applied to define an efficient grid architecture from a European techno-economic perspective. It relies on iterative simulations to assess the impact of different grid architectures.

The granularity of the results presented here is not as accurate as in a study that would tackle shorter time horizons, using a full grid model (like for instance the TYNDP approach of ENTSO-E).The clustering approach enables focusing on transmission needs between clusters only, thus being unable to detail the needs for intra-cluster reinforcements. The priority is therefore given to the detection of major electric energy transmission issues, meaning long distance and large capacity reinforcements (often higher than 2 GW), forgetting about the possible necessity of smaller reinforcements. Quite often, more than one route is possible to reach the same electric system objective. As a result, it may be possible to identify routes which differ from those suggested in the study, but which fulfil similar requirements.

The approach relies on estimated GTC as a result the operational issues of the grid were not fully assessed. Additional investment to ensure operability might be necessary but their cost should be small in comparison to the ones discussed here.

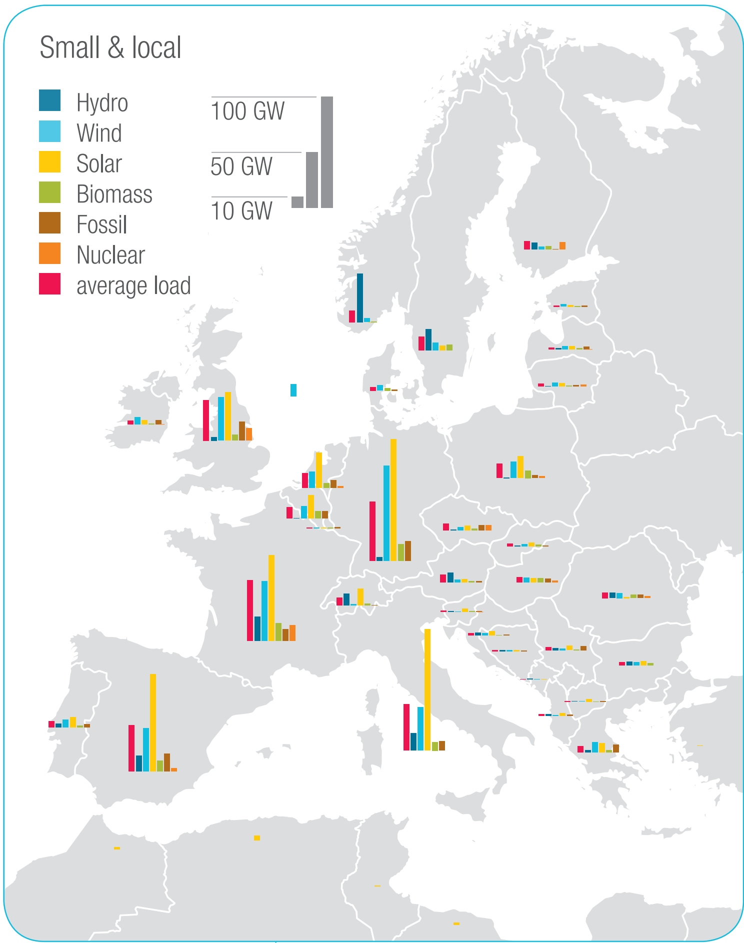
See deliverable D2.3 for more details

4.1 Grid architectures for 2050

Figures 12 A to E provide an overview of the generation installed capacity and the proposed new transmission reinforcements in support of each of the five scenarios.

At first glance, the predominance of “North to South” corridors appears clearly: all scenarios have several reinforcements that connect the North of the pan-European electricity system (North Sea, Scandinavia, UK, Ireland), and southern countries (like Spain and Italy), to the continental synchronous area (northern Germany, Poland, Netherlands, Belgium and France)

The scenarios *100 % RES* and *Large-scale RES* lead to greater transmission requirements (size and distance) than the *Small & local* and *Fossil fuel & nuclear* scenarios. *Large-scale RES* and *100 % RES* show the importance of major infrastructures in the center of the continental system. This adds to the peripheral network investments required by all the scenarios: the volumes of renewables in both scenarios, especially coming from the North Sea, are such that all the corridors from these sources to the major load centres need to be reinforced.



Small & local – 2050

Generation capacities and average load (left) and consequential transmission requirements (below)

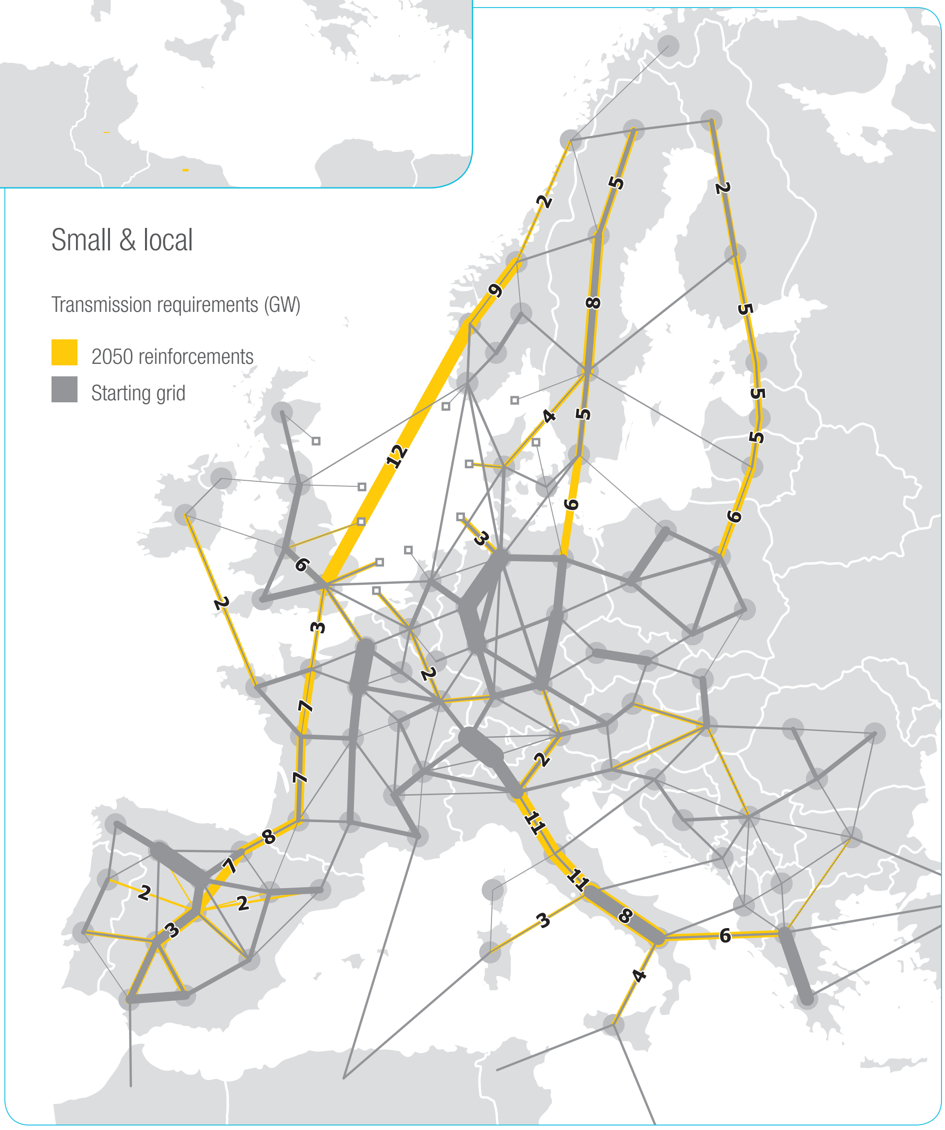
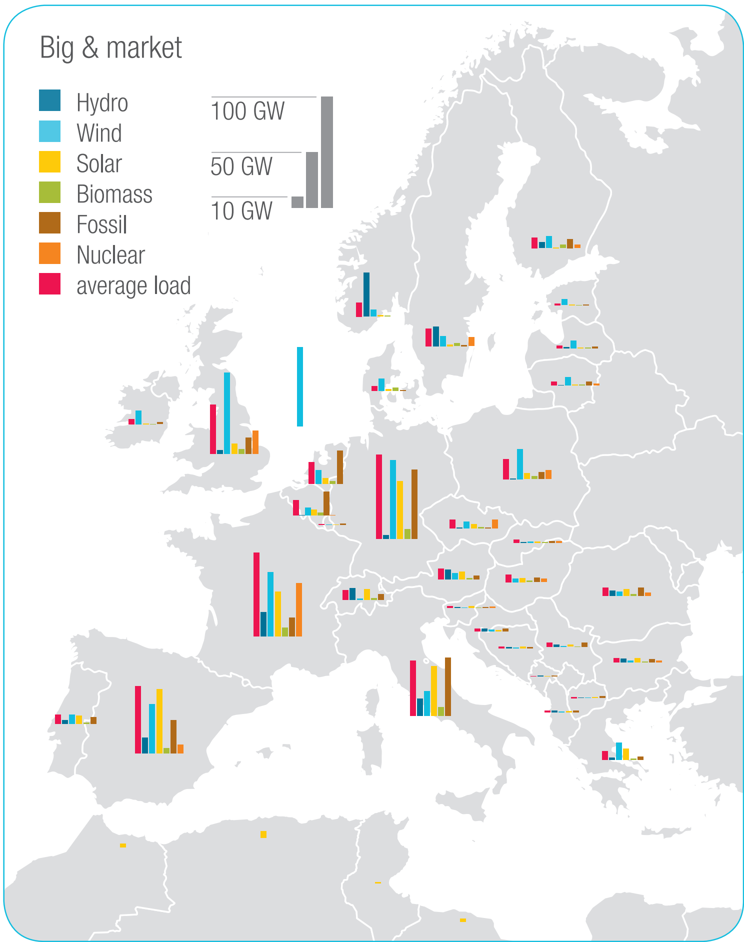


Figure 12 A: Transmission requirements identified in scenario *Small & local* (GW)

Big & market – 2050

Generation capacities and average load (left) and consequential transmission requirements (below)



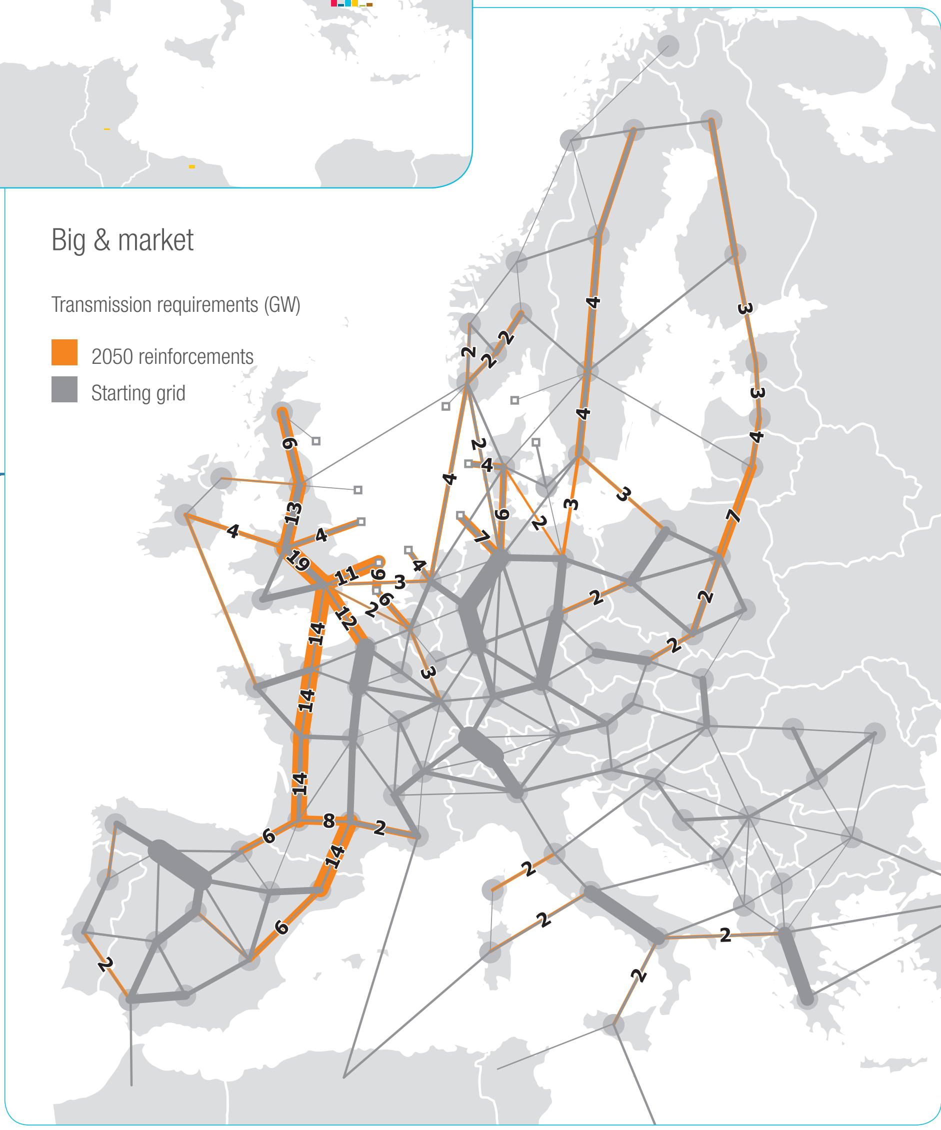
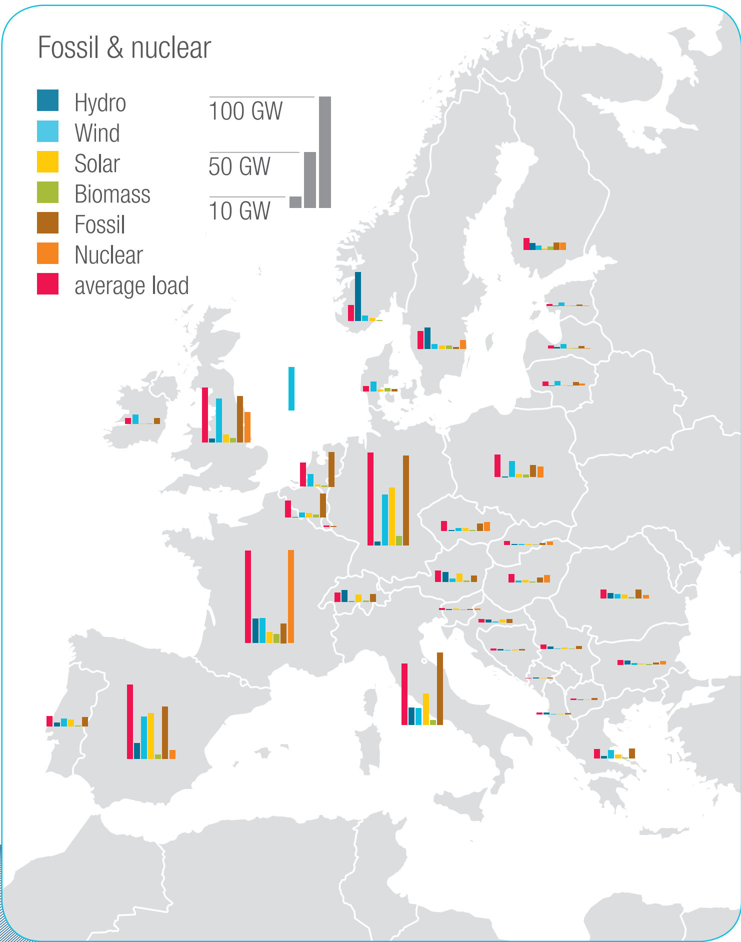


Figure 12 B: Transmission requirements identified in scenario *Big market* (GW)

Fossil & nuclear – 2050

Generation capacities and average load (left) and consequential transmission requirements (below)



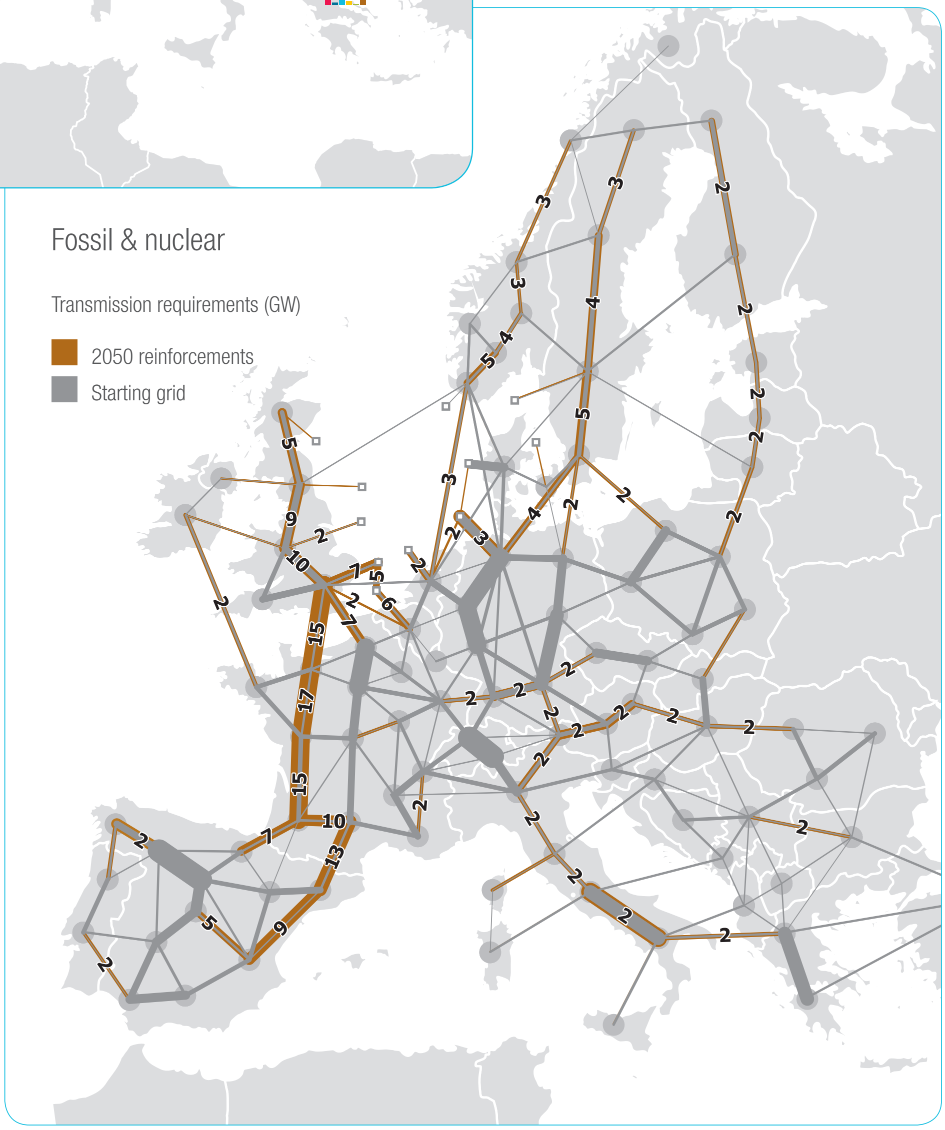
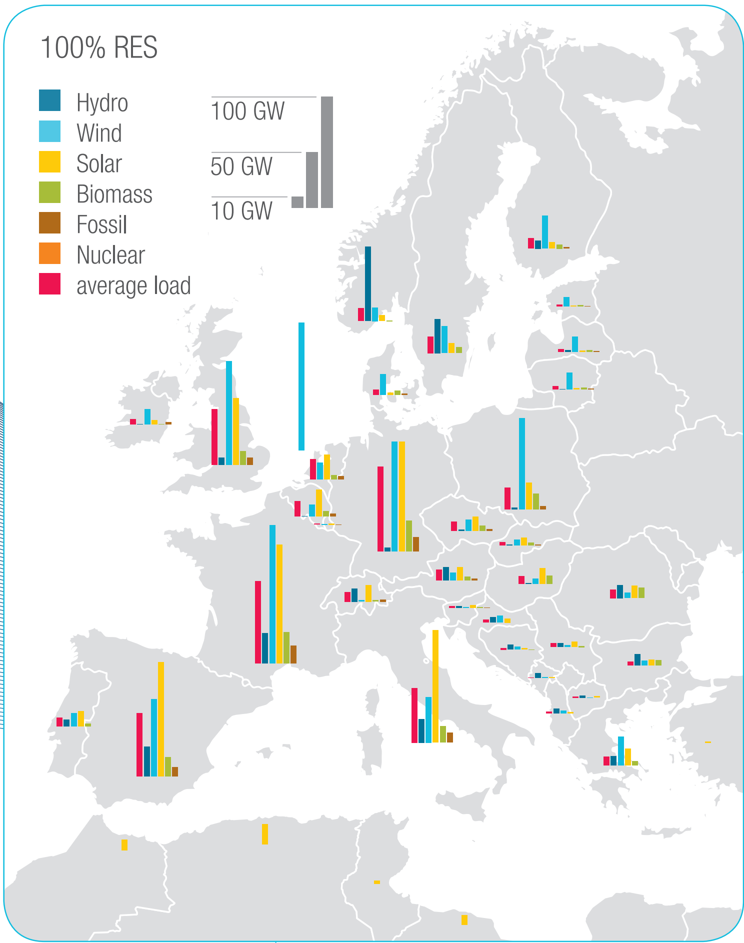


Figure 12 C: Transmission requirements identified in scenario *Fossil & nuclear* (GW)

100% RES – 2050

Generation capacities and average load (left) and consequential transmission requirements (below)



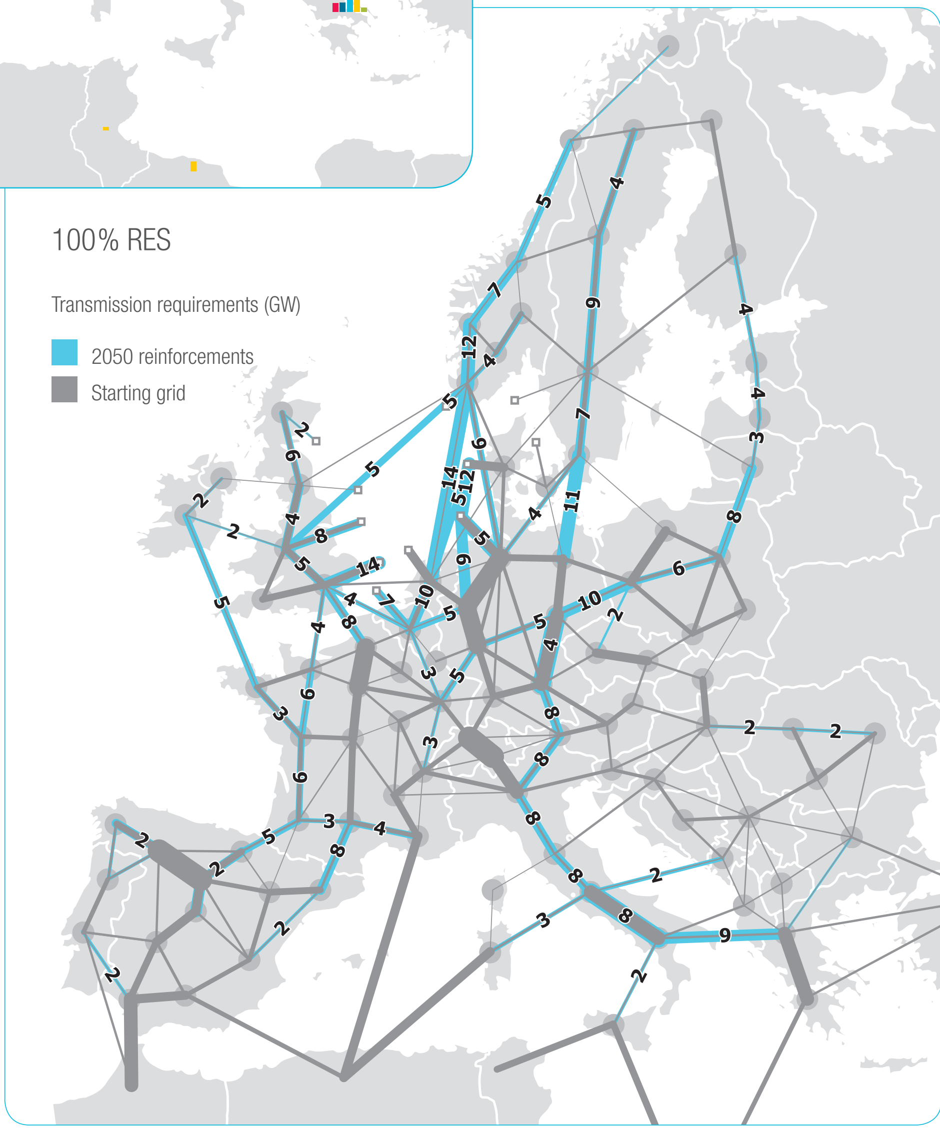
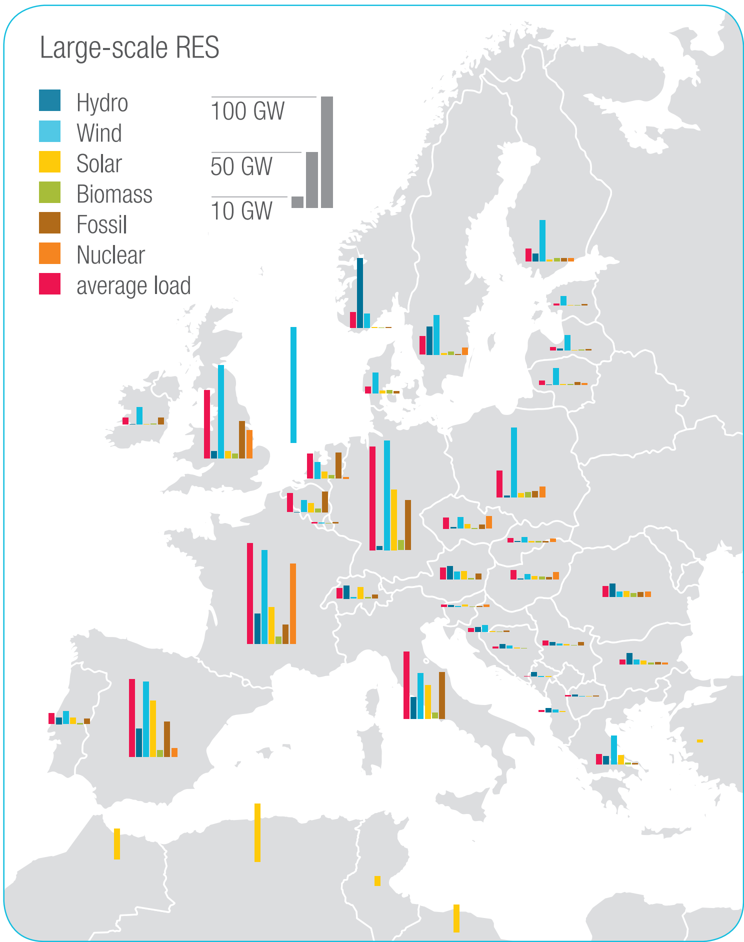


Figure 12 D: Transmission requirements identified in scenario *100 % RES* (GW)

Large-scale RES – 2050

Generation capacities and average load (left) and consequential transmission requirements (below)



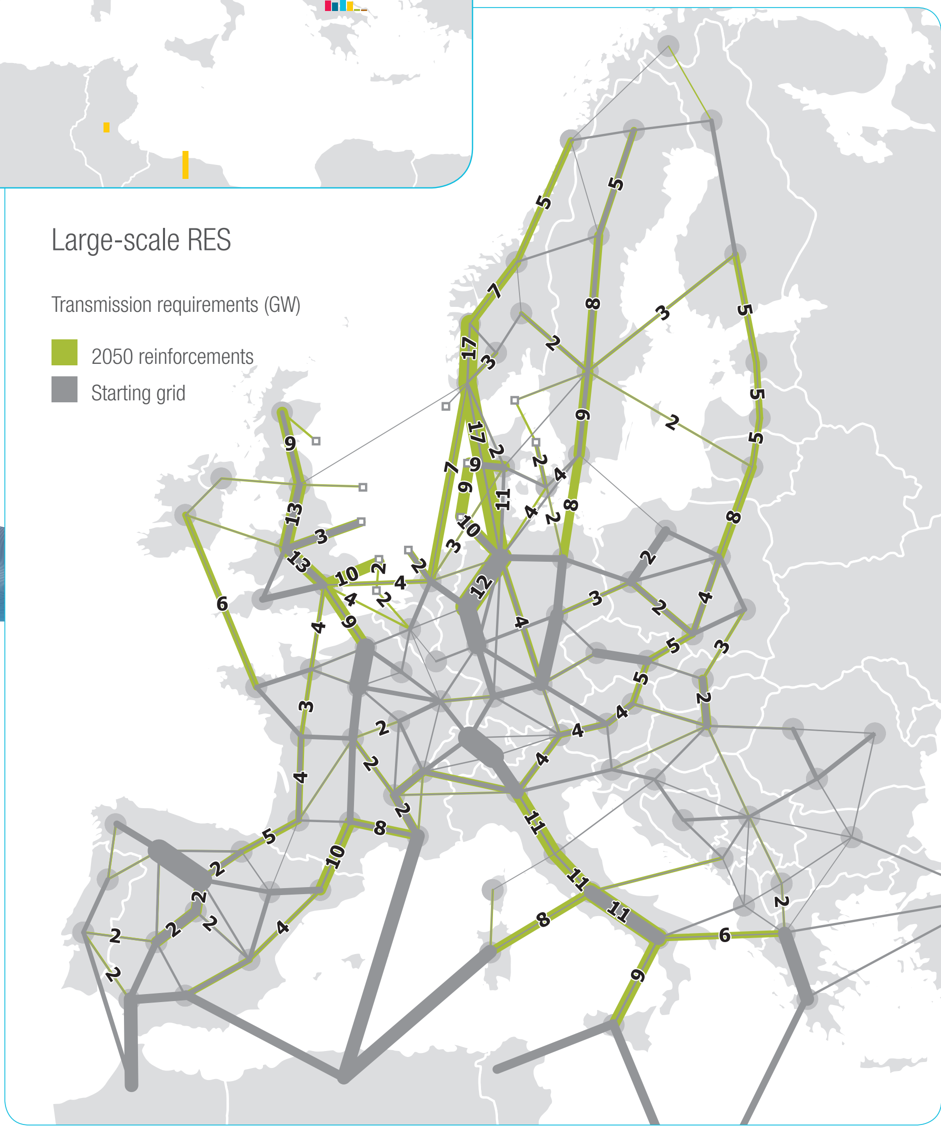


Figure 12 E: Transmission requirements identified in scenario *Large-scale RES* (GW)

Even if the scenarios are extremely diverse, some major corridors are common to all of them.

They appear robust to face the large uncertainties in 2050 and are thus good candidates for mid-term grid investments as further discussed in part 4.3.

Figure 14 pinpoints the similarities between the scenarios, emphasising only the corridors that have been reinforced in at least two of the covered scenarios. This figure also displays a reminder of the power ranges for the corridors to be developed.

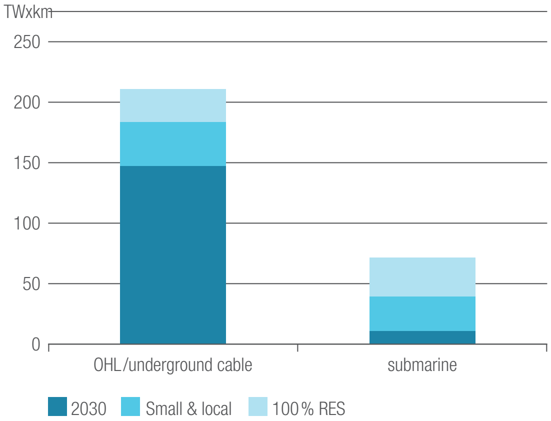


Figure 13: Transmission infrastructure capacities: The indicator shows the cumulative transmission grid capacities in TWxkm present in 2030, and the proposals for two extreme scenarios in 2050. This indicator includes new and refurbished infrastructures. In total, the increase is between + 40 % and 90 %, equally split between land and submarine.

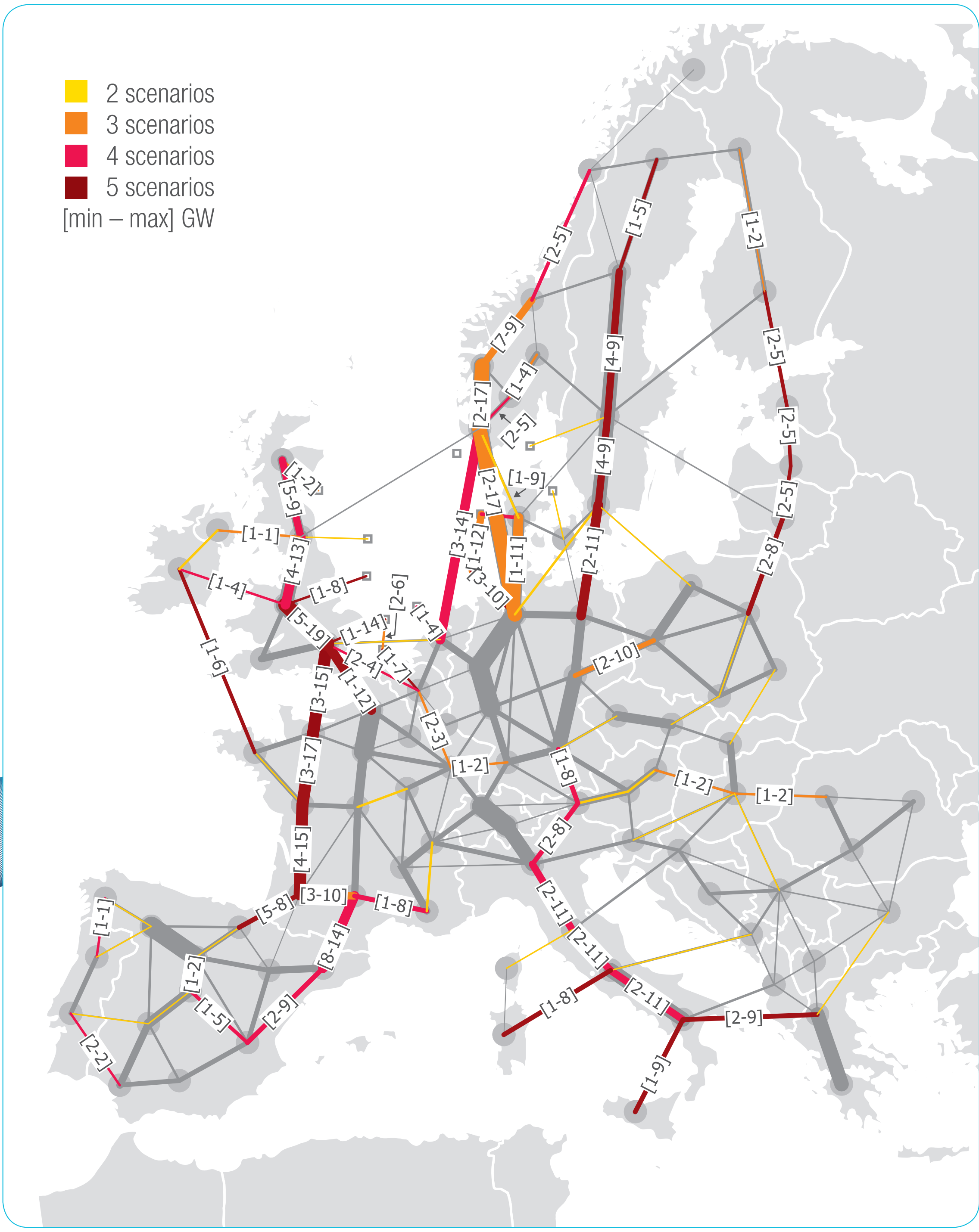
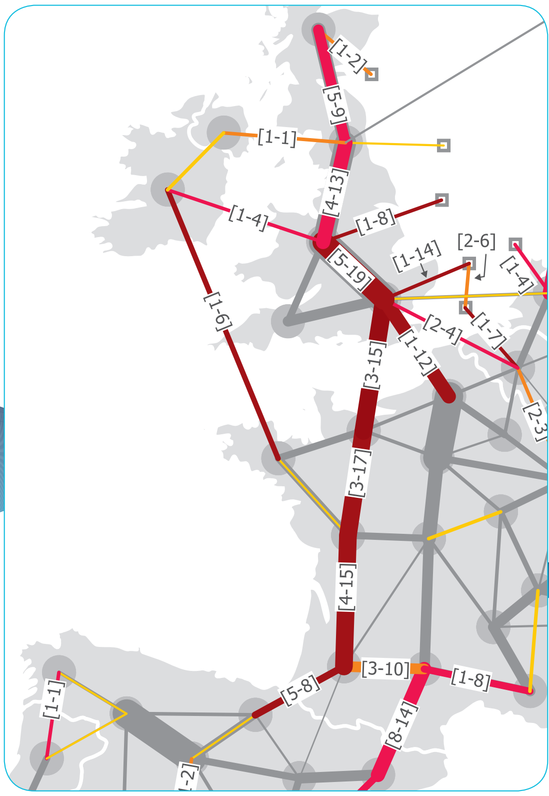


Figure 14: Common reinforcements (widths are according to average reinforcement capacity and the colour represents the number of scenarios where the reinforcement is needed)

The major common corridors are hereafter described and compared against the expected 2030 capacities. The foreseen evolutions relate to the huge changes in generation capacities which are also discussed below with respect to the 2012 figures.

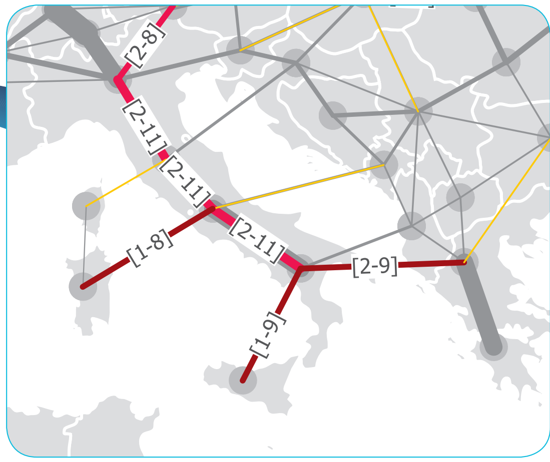
Great Britain and Ireland to Spain through France



In all scenarios, the need to connect the UK to continental Europe appears with a minimum of 6 additional GW *(Small & local)* and up to 31 GW *(Big & market)*. In parallel, another extra 1 to 6 GW is needed between Ireland and France: such interconnections are extended by a corridor crossing France down to Spain with a size ranging between 4 and 15 GW. The French-Spain interconnection is then reinforced between 8 GW *(Small & local)* and 20 GW *(Big & market, Fossil & nuclear)*. This corridor is also extended to include Scotland via internal British reinforcements. The three main drivers identified for this major corridor are:

- Wind generation in the UK, Ireland and the North Sea. In all scenarios, the total wind capacity in these areas increases between 51 GW *(Small & local)* and 223 GW *(100 % RES)*. This generation can exceed the local demand: it can then be exported to France and Spain.
- Nuclear in the UK and France. In the scenarios *Big & market* and *Fossil & nuclear*, the nuclear capacities are increased in the UK by more than 10 GW. In the *Fossil & nuclear* scenario, the nuclear capacity is also increased in France when compared to 2012. As a result, such scenarios require the highest capacities for the corridor, since it can be used to export nuclear generation to Spain in addition to wind generation.
- Solar in Spain and Portugal. The solar generation in Spain and Portugal increases between 40 GW (*Fossil & nuclear*) and 110 GW (*100 % RES*). It creates an opportunity for this peninsula to export solar generation to northern Europe.

Greece to Italy and the Italian backbone



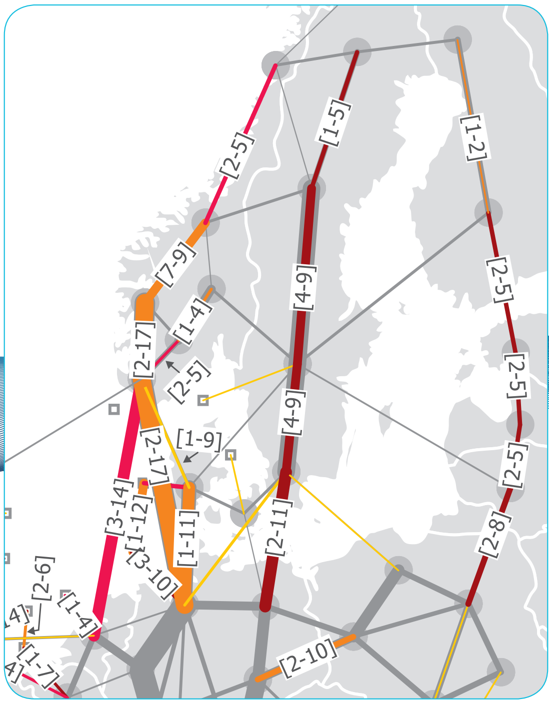
The Greece – Italy interconnection is reinforced in all scenarios between 2 GW *(Big & market, Fossil & nuclear)* and 9 GW *(100 % RES)*, while reinforcements Italy – Sardinia and Italy – Siciliy are also foreseen in all scenarios. The Italian corridor is reinforced in all scenarios, except for the *Big & market* one with a maximal value of 11 GW in the *Large-scale RES* scenario. The main drivers for such reinforcements are:

- Wind generation in Greece. Wind capacity in Greece is increased between 6 GW *(Fossil & nuclear)* and 24 GW *(Large-scale RES, 100 % RES)*. This generation can exceed the local demand and be exported towards Italy.

- Solar generation in Italy. The solar generation in Italy increases between 15 GW *(Fossil & nuclear)* and 96 GW *(Small & local)*. Although it is mainly located in the North of the country close to the demand centres, significant volumes still need to be transported from the South to the North of the country.

- Connection to North Africa. In the scenarios *Large-scale RES* and *100 % RES*, significant connections from Northern African Countries to Italy are assumed (40 GW in *Large-scale RES* and 10 GW in *100 % RES*). The solar generation coming from these countries need to cross Italy to reach large electricity demand centres.

Norway and Sweden to Continental Europe and the UK



In all scenarios, the need to further connect Norway and Sweden with the rest of Europe is emphasized. The additional interconnections between Sweden and Continental Europe range from 6 GW *(Big & market)* to 15 GW *(100 % RES)*: they are extended by a 4 to 9 GW corridor across Sweden. From Norway to Continental Europe and the UK, the additional capacity is between 1 GW *(Fossil & nuclear)* and 19 GW *(Large-scale RES)*. Significant reinforcements from Scandinavia are connected to the German North-South DC corridors which enable the further transport of electrical energy within continental Europe. The main drivers for these reinforcements are:

- Hydro power in Norway and Sweden. Hydro power in these two countries is currently around 50 GW. In the scenarios, an increase of between 11 GW *(Big & market)* and 50 GW *(100 % RES)* is assumed. The resulting generation can exceed local needs and be exported to the rest of Europe. Moreover, hydro power is crucial for the whole European system bringing critical flexibility levels to the electricity system. The resulting interconnections should be sufficient to allow for high export peaks during critical periods.

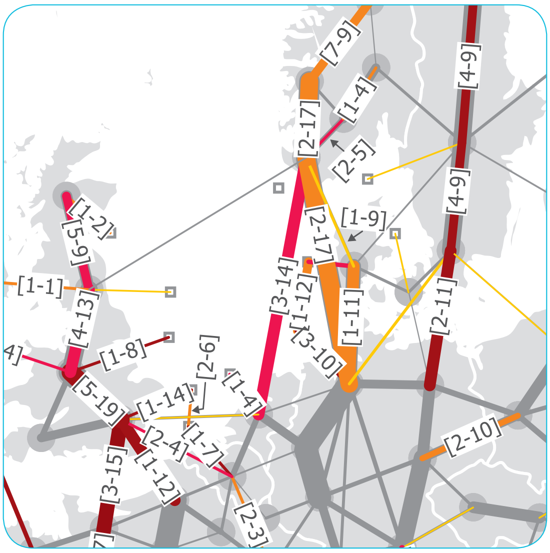
- Wind in Norway and Sweden. Wind capacity in Norway and Sweden is assumed to increase between 5 GW *(Fossil & nuclear)* and 45 GW *(Large-scale RES)*. The resulting generation can exceed local needs and be exported to the rest of Europe.

- Nuclear decommissioning in the UK and France. Connections from Norway to the UK appear only in the scenarios *100 % RES* and *Small & local*. In such scenarios, almost all of the nuclear generation is decommissioned in France and the UK (–47 GW and –73 GW, respectively). As a result, the western part of Europe needs power supply.

Finland to Poland through the Baltic States

A 2 GW *(Fossil & nuclear)* to 5 GW *(Large-scale RES)* corridor connects Finland to Poland through the Baltic States. The main driver for this corridor is the development of wind generation in the area. For Finland, it increases between 2 GW *(Small & local)* to 37 GW *(Large-scale RES)*. For Latvia, Lithuania and Estonia, it stands between 8 GW *(Small & local)* and 36 GW *(Large-scale RES, 100 % RES)*. The large transmission needs are also explained by the relatively small system size; the peak load in Finland is currently 14 GW and in the Baltic area 4 GW.

The North Sea area



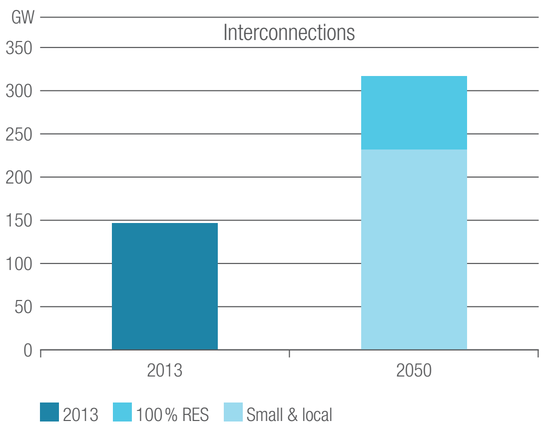
In the initial grid, the capacities of the radial links are only around half of the installed offshore wind capacities. Further reinforcements have been assessed within the study. The main conclusion is that by 2050 some offshore clusters with huge volumes of wind power are not close to the clusters exhibiting energy deficits. For instance, the offshore cluster near western Denmark appears interesting to provide energy to Continental Europe rather than to Denmark which does not need all of it. In this case, there are several possible routes to go from an offshore cluster to clusters exhibiting energy deficits (Germany for instance):

- either through Denmark (radial connection to Denmark and extra capacity between Denmark and Germany);
- and/or through a circular meshing between the offshore North Sea clusters (offshore cluster close to Denmark, towards the offshore cluster close to Germany and the cluster located in North Germany).

Another example deals with an offshore cluster close to southern UK: a huge part of its wind power is useful for northern Continental Europe through Belgium. The path could then be:

- either through the UK;
- or through a circular meshing between the offshore North Sea clusters (offshore cluster close to the UK towards the offshore cluster close to Belgium and then Belgium);
- or directly to Belgium.

The optimal choice between such possible paths requires a detailed analysis which is beyond the scope of the e-Highway2050 project.



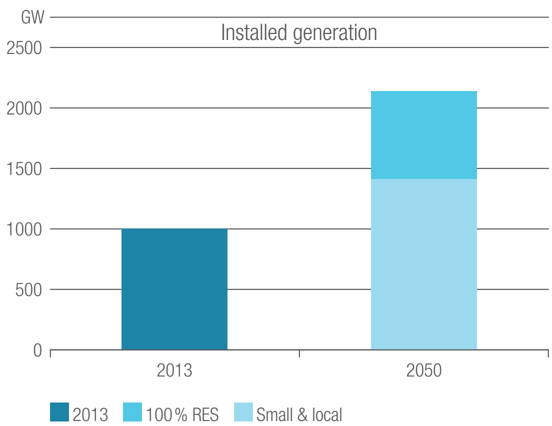


Figure 15: Interconnection capacities: The left figure presents the cumulative interconnection capacities (physical and not commercial). The increase foreseen by 2050 is consistent with the evolution of the installed generation.

4.2 Cost benefit analysis

For each scenario, a comprehensive Benefit-Cost Assessment (BCA) of the grid architectures is performed. This BCA is implemented in a toolbox aimed at allowing an automatic application of the methodology starting from the scenario simulation files and allowing a complete appraisal of the cost/benefit indicators

See deliverables D6.x for more details

Cost estimation

Considering the accuracy of the study, only indicative cost estimates are possible: thus only minimal and maximal values have been assessed. Minimal cost valuation assumes that AC overhead lines (OHL) can systematically be used for terrestrial lines. Maximal cost valuation assumes that DC underground cables are preferred for all terrestrial connections.

For the three less constrained scenarios (*Big & market*, *Fossil & nuclear* and *Small & local*), the resulting total investment costs lie between 120 and 220 billion Euros, depending on the acceptance of new overhead lines or the preference for DC underground cables. In the scenarios *Large-scale RES* and *100 % RES*, the resulting architecture is almost twice as expensive, reaching a total cost of about 250 billion Euros for OHL, and about 390 billion Euros for DC cables.

Benefit estimation

In all the scenarios, the resulting grid architectures do cope with the issues of unsupplied demand, RES curtailment and CO_2 emission increases. Indeed, the grid reinforcements reduce the unsupplied demand by between 5 TWh *(Small & local)* and 50 TWh *(100 % RES)*. For RES curtailment, the reduction ranges between 40 TWh *(Fossil & nuclear)* and 465 TWh *(100 % RES)*. Finally, the annual CO_2 emissions go down by between 23 Mt (*Small & local)* and 192 Mt *(Large-scale RES)* and are below 100 Mt in all the scenarios after the grid reinforcement.

The architecture benefits are compared to the costs using the following monetization parameters:

- Energy Not Supplied (ENS): the reinforcement proposed avoids the cost of additional generation in order to face ENS (see Section 3.4). For each scenario, the cost of such additional generation is taken as the ENS cost.
- Fuel savings: the reinforcements allow for the use of cheaper generation, thus reducing the generation costs.
- CO_2 reduction: it is monetized considering a cost of 270 €/t.

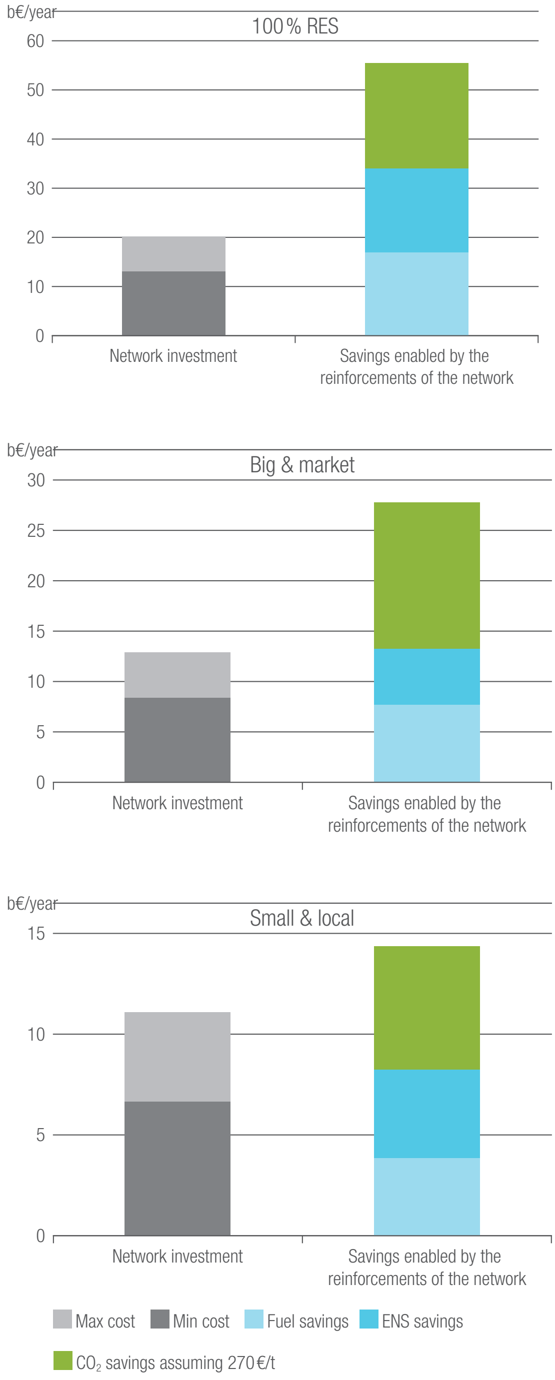


Figure 16: Grid annuities of investment and benefits for the scenarios *100 % RES*, *Big & market* and *Small & local*

Depending upon the studied scenario, the annuities of investment lie between 10 and 20 billion Euros assuming a discount rate of 5 % whereas the annual benefits lie between 14 and 55 billion Euros, with the expected benefits largely exceeding the foreseen costs in all the scenarios (see three of the five scenarios in Figure 16). Actually, for all the scenarios, except the *Small & local* one, the investment costs are even covered without considering the benefits coming from CO_2 emissions.

4.3 Going from 2030 to 2050

To identify the modular development of the 2050 architectures, a "least regret" grid architecture is defined for 2040. It is created by using a subset of the 2050 reinforcements, aiming at solving as many problems as possible at horizon 2040, while still being profitable in each scenario. As a result, constraints may still persist with this minimal grid and dedicated extra reinforcement may consequently be needed. Nevertheless, this minimal grid constitutes an interesting portfolio of project to be further investigated, as they prove to be robust in the framework of this study for five very contrasted scenarios. As depicted in Figure 18, the main corridors identified in 2050 do already exist in 2040, but with a smaller capacity due the shorter time horizon, and also to be compatible with the five different scenarios.

The total investment cost of this architecture is estimated to lie between 50 and 100 b€ depending upon the implemented reinforcement technologies. As depicted in Figure 17, the benefits (more than 5 b€/year) largely exceeds the investment annuities (3 b€/year) in all the scenarios if over-head lines are used for terrestrial connections. If DC cables are used instead, the scenarios with the less renewable (*Big & market*, *Fossil & nuclear*) provide benefits close to the annuity (5.6 b€/year). Conversely, the "extreme" scenarios *Large Scale RES* and *100 % RES* show huge benefits whatever the reinforcement technology is.

For the scenarios *Small & local*, *Fossil & nuclear* and *Big & market*, the investment needs for this minimal 2040 grid stand around half of those foreseen for 2050, ensuring a smooth spreading of the investments until 2050. Nevertheless, for these scenarios, additional smaller reinforcements may also be necessary to take care of the 2040 scenario-specific needs. For instance, the development of nuclear in the UK, like in the scenarios *Big & market* and *Fossil & nuclear*, would require more interconnections with the continent. More connections within Spain and Italy would be necessary if a further development of PV generation is combined with a rather low electricity demand in these countries.

For the two other scenarios, *Large Scale RES* and *100 % RES*, this minimal architecture is far from solving the issue of RES curtailment appearing in 2040: more than 100 TWh are still curtailed annually. If the future appears to be in line with those two scenarios, thus characterized by significant increase of the electricity demand and of centralised RES, additional major reinforcements should be considered by 2040, in line with the 2050 architectures.

See deliverable D 4.3 for more details.

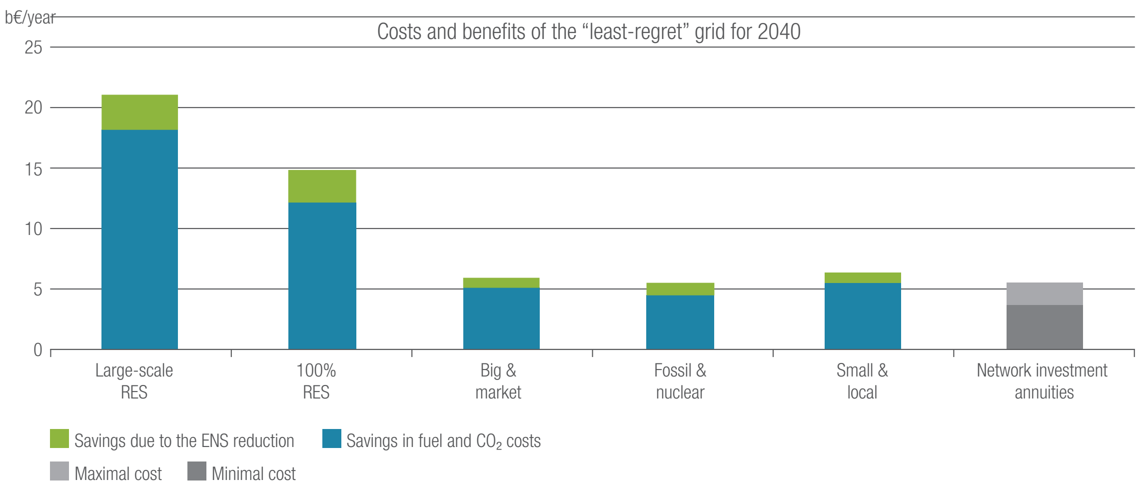


Figure 17: Costs and benefits of the "minimal" grid for 2040

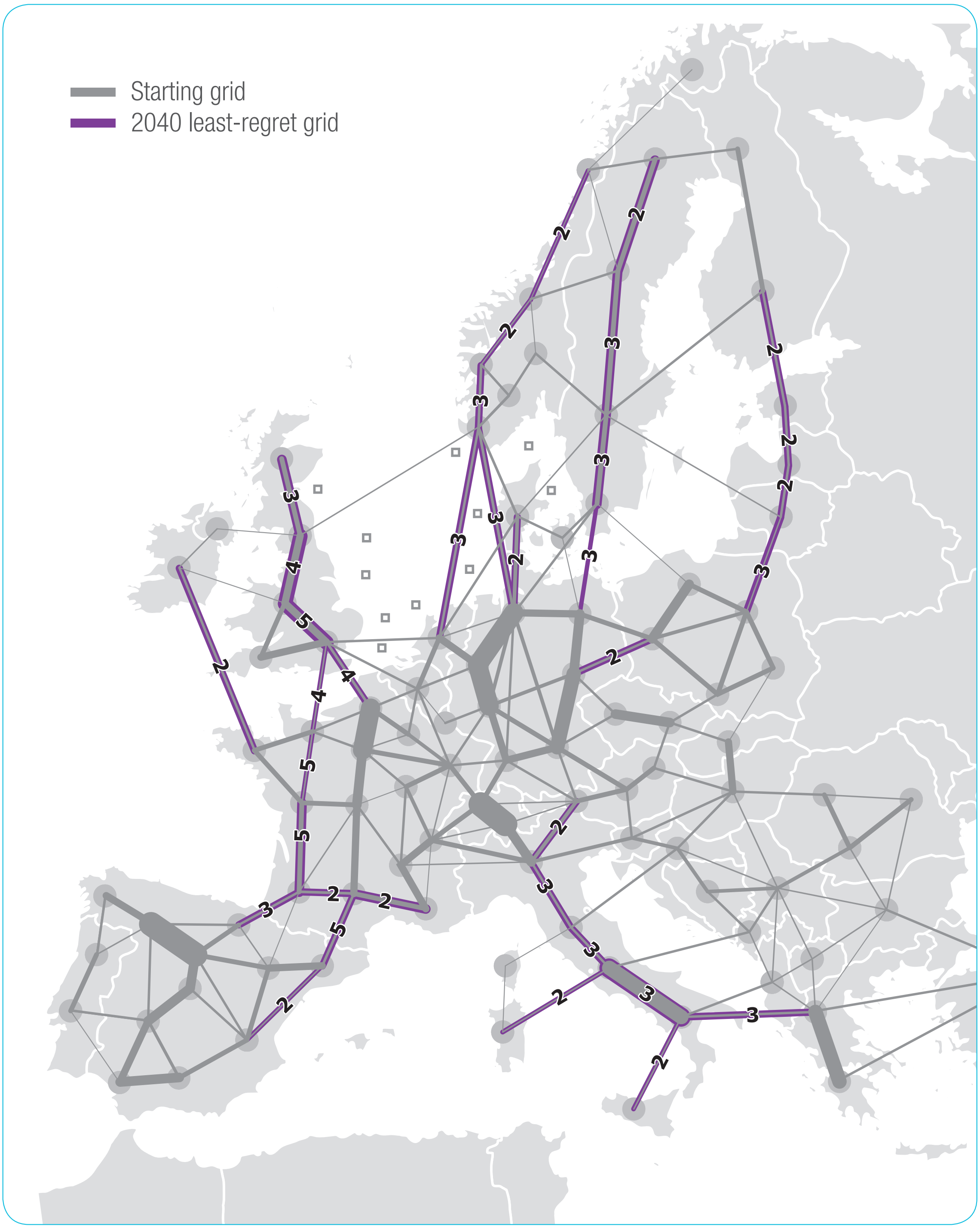


Figure 18: Grid architecture for 2040, robust to the five scenarios (grey: starting grid; purple: reinforcements)

5 How to deploy and operate the resulting grid architectures?

5.1 Which technology?

The cooperation in the e-highway2050 consortium between TSOs and manufacturers (T&D Europe and Europacable) has allowed the identification of technological needs, beyond what is today commercially available, keeping in mind that the cluster approach prevents from addressing specific requirements for a given reinforcement. An available technology option[16] herein means either an already implemented solution in a transmission system in some other part of the world, or a solution under development with an expected deployment under short-term time horizons[17].

Figure 19 and Figure 20 depict the various gaps between the not yet covered areas by available technological options and the new lines and reinforcement needs (orange cells) in a two-dimensional space, i.e. power and distance. The orange cells in both figures pinpoint the new lines and reinforcement needs coming out from the grid architectures presented in section 4. The light blue areas cover overhead line (OHL) technologies, whereas the dark blue ones stand for solutions under development. The purple colour in Figure 19 is dedicated to underground cable (UGC) solutions. The available technologies and the ones under development have been mapped with the list of technologies available in the e-Highway2050 database (see deliverable D3.1).

For terrestrial HVAC applications, in addition to the widespread technologies for 400 kV OHL (conventional conductors and reduced number of bundles), the following options are of interest:

- HVAC overhead lines with different designs (number of circuits), various conductor types (high temperature low sag) and more bundles so as to reach higher power over short distances,
- HVAC XLPE underground cables[18], in order to provide partial undergrounding solutions which will complement overhead lines in sensitive areas or areas where public acceptance of OHL is low,
- HVAC OHL consisting of several lines for very high power and short to medium distances (interest for such solutions strongly relies upon the maximum capacity of one line which is acceptable from the TSO point of view, cf. N-1 security criteria in case of a contingency)

For terrestrial HVDC applications, underground cables have proven their reliability and attractiveness for long distance power transmission and are now being seen as a solution for future long distance transmission based on the experience gained from long HVDC submarine cable links.

In the longer term, other options might be of interest:

- higher voltage AC lines – typically 550 kV – when addressing longer distances at medium power (where several 400 kV lines could also provide an acceptable solution),
- with high power VSC converters, and more specifically switchgear equipment becoming mature and gaining market experience, meshed HVDC networks could become possible, thus creating local meshed HVDC networks in Europe. HVDC meshed networks could be implemented with OHL technologies but also with HVDC cables over long distances[19].

For submarine transmission network development, there are today available technologies for all distances up to medium power, cf. Figure 20. The chal-

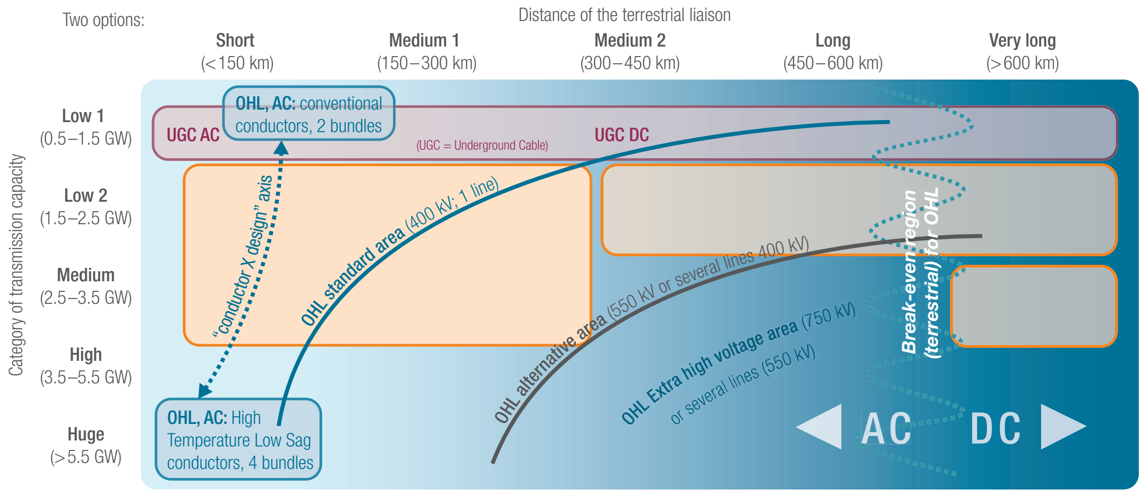


Figure 19: RD&D gap analysis: terrestrial needs (orange cells) compared to available technology options (OHL options: various grades of blue, from the more conventional to the less conventional; terrestrial cables options: in purple color)

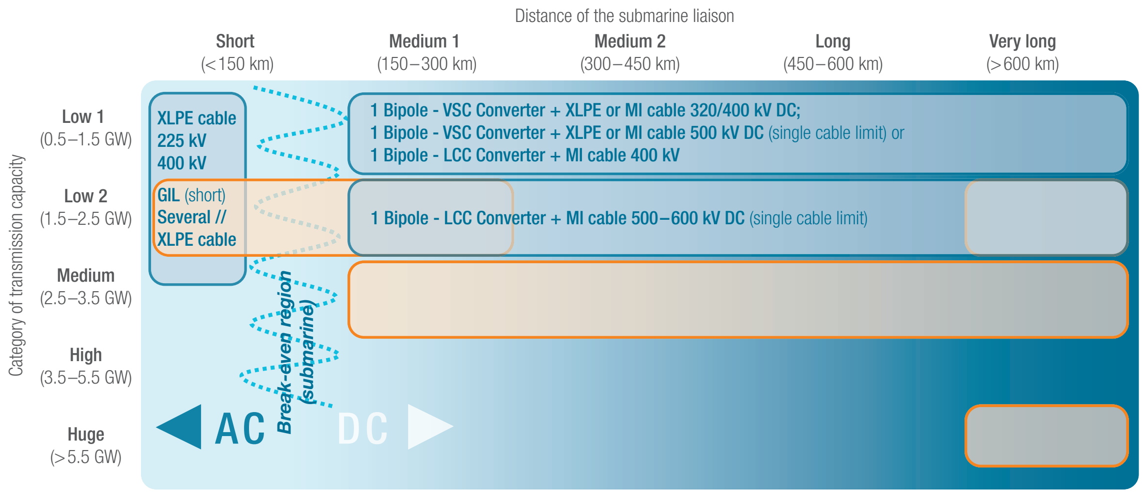


Figure 20: RD&D gap analysis: submarine needs identified in the simulations (orange cells) compared to available technology options (blue cells)

lenge is to improve the efficiency of these technologies, both in technical (decrease of losses and failure rates, increase of possible depths) and economic (investment and O&M costs) terms.

For higher power submarine liaisons over all distances, the main challenges are to reach higher voltages and intensities, as well as to increase the installation depths so as to exceed 2 500 meters in the coming decades with lighter cables. Like for terrestrial applications, the development of HVDC meshed networks is expected (in the North Sea for instance for the interconnections of offshore windfarms) with multi-terminal HVDC systems at sea[20].

A limited set of modular solutions for terrestrial and submarine liaisons could, when combined[21], meet most of the new line and reinforcement needs identified in the study. In such a case, a balance should be found between the economies of scale and the wide range of possible links at the pan-European scale.

Technologies such as Gas Insulated Lines (GIL) and superconducting cables might be of interest in the long run, probably in densely-populated areas where huge amount of power have to be transmitted underground[22].

For the gap identified on high power to be transmitted over long distances two different paths are open for further RD&D studies, both routes deserving to be explored by the stakeholders of the electricity value chain:

- to increase the transfer capacity of conventional cables (such as XLPE);
- to keep on developing solutions with high transfer capacity, such as superconducting cables, and improve their economic efficiency for long distance applications.

See deliverable D 3.2 for more details

5.2 Which regulatory framework?

In view of the evolution of the European grid architectures up to 2050, potential adaptations to the current regulatory framework to realise these projected grid architectures might be necessary. The European grid will by 2050 inevitably be more interconnected than today, spanning more countries and transporting even more energy from distant production centres to diverse consumption areas. In order to face the challenges for such grid architecture realisation, a set of key governance principles has been elaborated by means of best practices derived from worldwide experiences, which can be considered for future European regulation.

Towards a more coordinated grid planning

Current approach adopted for grid planning at European level has already been evolving from a purely bottom-up process at national level towards a more centralised and European shared approach. This evolution is supported by the work carried out by ENTSO-E in the TYNDP definition process, which combines top-down planning elements with a bottom-up approach. Such an approach allows taking into account the local knowledge of the regional and national networks and their specifics and investment needs. Moving forward, this evolution towards a more centralised approach is to be further supported, whilst at the same time ensuring that the bottom-up and national elements remain a key part of European grid planning. Even though continued efforts will be necessary to increase public acceptance of electricity transmission, this evolution towards a more coordinated, European-wide grid expansion planning process, interacting with national ones, is considered as the efficient way to correctly and timely identify main grid bottlenecks and related infrastructure projects. Identifying these is a necessary first step in their realisation, in order to evolve towards a truly interconnected European network.

Towards continuously improved financing conditions

One of the key challenges to ensure a swift project realisation is providing the necessary financing conditions for the transmission network owners to finance the construction of infrastructure. Public sector support and rate-adders for strategic projects could push the project forward by financial stimuli throughout the most risky project phases, but may be insufficient to overcome the entire challenge.

To provide the correct signal for transmission network investment, it is fundamental to create a fair, stable and predictable risk-reward mechanism which takes into account the different life-cycle stages of an infrastructure project. This implies that regulatory regimes should provide a forward-looking, long-term commitment and provide clarity to limit regulatory risk for investors. Whenever a fair and commensurate risk-reward mechanism is ensured, in a stable context with regulatory comfort for the conditions, there should be no barrier to a timely project realisation. Fall-back solutions in case of failure of timely delivery of the project for reasons lying under the control of the TSO should however be foreseen.

Towards an appropriate and fair cost allocation of network investments

Given that costs and benefits of network investments will be increasingly spread out over several countries, further coordinated cost allocation of grid reinforcements is foreseen for projects having a cross-border impact. To this aim, a unique, robust and binding methodology should be developed for cross-border cost allocation (CBCA). In the short term, and as long as there is not sufficient consensus on the appropriateness of the method for the computation and allocation of benefits of reinforcements to countries, multilateral CBCAs should only be applied in exceptional cases, rather than as base case. In the long term, multi-criteria cross-border cost allocation agreements could be applied more widely, if a(n updated) feasibility study indicates positive results.

Furthermore, the higher complexity of electricity systems by 2050, characterized by higher shares of RES, more variable electricity demand (electric vehicles, heat pumps), imply a higher diversity of costs and benefits that network users incur on the system. Since network charging structures currently often take a typical average situation as point of departure, increasing gaps between network charges and true costs of network users for the grid are observed. This results in a lack of incentives to generators and loads for optimal use of the network in many member states. Consequently, network costs could be allocated as far as possible by applying the "beneficiary pays" principle, which is theoretically the most appropriate, but could be difficult to implement. In any case, the future mechanism should provide efficient economic signals to all network users, both generation and demand. Likewise, when RES becomes a mainstream technology, RES network costs should no longer be socialized through priority access or dispatch, but allocated to RES facilities that benefit from them. Cost components that cannot be indisputably allocated to a specific (group of) stakeholder(s) and reliability network costs ('N-1' costs) should however remain to be socialized.

Towards a more coordinated system operation

As for system operation aspects, further coordination between actors and integration of market mechanisms needs to take place. First and foremost, there is a clear need to complete the internal energy market and to ensure regional market integration in all time-frames (forward, day-ahead, intra-day and real-time). The recent implementation of the flow-based mechanism serves as an example for the future in that regard. Related to that is the bidding zone configuration, which should be, as long as zonal transmission capacity allocation is pursued, configured in a way which corresponds to real network bottlenecks.

Furthermore, it will be crucial to incentivise market actors to ensure correct and rational behaviour in order to tackle ever-increasing system security aspects. Well-designed balancing markets are a key requirement and electricity markets should contain a well-defined resource adequacy objective. These objectives should be defined on a more regional basis. If they lead to the elaboration of capacity markets, then they should be deployed in a way compatible with the European wide energy market. In addition, and to deal with the high share of renewable generation, further regional security monitoring and control mechanisms closer to real-time over larger geographical areas are put forward. Finally, integrated systems will require further information exchange and harmonization of procedures by means of common tools, data and processes among TSOs to deal with the variable and uncertain cross-border power flows.

See deliverable D5.1 for more details

5.3 How to operate the resulting power system

System operation will be challenged in the future by the major changes expected in the European electrical system. Three main sources of change are identified, each having a potential impact on the different operating issues:

- The increasing penetration of renewable energy sources: RES behave radically differently than traditional plants (small power electronics device vs. large synchronous generator). In four of the five e-Highway2050 scenarios, during some hours, they are the only generating units connected to the grid, supplying entirely the European load.
- The increasing power exchanges: All the e-Highway2050 scenarios show significant European power flows on the transmission grid.
- The increasing number of connections realized with HVDC: HVDC behaves very differently than AC lines. Today, a few DC lines exist in the European system to connect non-synchronous areas and only one DC link is implemented in parallel to AC lines. In e-Highway2050 scenarios, at least 50 GW of more HVDC are foreseen in addition to the 2030 projects of the TYNDP.

Power flows control

In comparison to flows on AC lines, which are determined by Kirchhoff's laws and the topology of the system, HVDC lines are connected via power electronics (PE) and can be actively set by TSOs. The advantage is a better control and a greater flexibility. The drawback is that HVDC are not responding "naturally" to the variations or contingencies affecting the power system and thus efficient coordinated control rules have to be implemented by TSOs.

Within the project, load flows simulations of the full transmission network of the continental synchronous area were performed for each scenario for two snapshots: winter peak and summer offpeak. The model was built from ENTSO-E 2030 grid with the inclusion of the 2050 inter-cluster reinforcements. For terrestrial reinforcements, two strategies were compared: AC and DC. A security study, comparing "N-1" and "N" situation, was then performed. In the simulations performed with AC reinforcements, the architectures are robust but with DC reinforcements, overloads appeared when fixed setting points were assumed. It highlights the need for smarter control rules of HVDC.

Voltage control

TSOs have to operate the system within secure voltage limits. The drastic change in the power system expected by 2050 will probably need adaptations in the reactive power compensation means. To assess these issues, AC load flows were tested within the project. For the two most extreme scenarios, *Large Scale RES* and *100 % RES*, no convergence could be found. The reason is that existing methodologies and tools are inadequate to easily study such different network configurations. In parallel, in the R&D part of the project (see deliverable D 8.5), an innovative algorithm has been developed to tackle these problems by automatically adapting the reactive power compensations. It could be applied in future studies.

Today, traditional plants are the main contributors to voltage control and their modeling in simulation tools are mature and quite realistic. This is not the case for wind and solar generators which are not systematically taking part to reactive power control and voltage support although it is technically feasible. Without this participation, the situation will no longer be manageable with more RES. This has to be anticipated in network codes and simulation tools should be adapted. HVDC converters also offer new possibilities for voltage control.

Dynamic stability and protection schemes

Traditional plants are synchronous generators; their behavior is well known by TSOs. On the contrary, HVDC, wind turbines and solar panels are connected to the AC grid via power electronics. Their dynamic behavior is completely different. Preliminary studies were conducted within the project but research is still needed to fully assess the impact of their increasing penetration. The "Migrate" research project funded by the EC will start working on this topic in 2016.

See deliverables D 2.4 and D 4.1 for more details

5.4 How to balance demand and generation

Scenarios like *Big & market* and *Fossil & nuclear* might be manageable with current practices but the scenarios with more renewable generation create real challenges to ensure the balance between generation and demand.

High needs of peak power

The profile of the residual demand (demand minus non-dispatchable generation) is drastically modified with the high share of renewable as depicted on Figure 21. The residual demand has to be covered by thermal and hydro power plants, storage and demand-side management. In the scenario *100 % RES*, the residual demand can reach more than 400 GW during some critical hours; this becomes challenging for this scenario if fossil plants have to be discarded. Moreover, the profitability of such units is critical since 200 GW of them (140 GW in the scenario *Small & local*) would be used 4 % of the year.

Need for extremely flexible dispatchable units

In an isolated country, the variability of wind generation might be a real challenge. However, thanks to the smoothing effect of the different European wind farms, European wind generation is rather stable. The high level of interconnections helps to take advantage of this asset: wind power creates a rather limited need for flexibility. As shown in Figure 22, at the European scale, the wind capacity factor never varies more than 2 % from one hour to the next, whereas in a smaller region it can vary by up to 10 %. Depending on the scenario, this variation means a change in wind generation from 7.5 GW/h for *Small & Local* to 15.2 GW/h for 100 % RES.

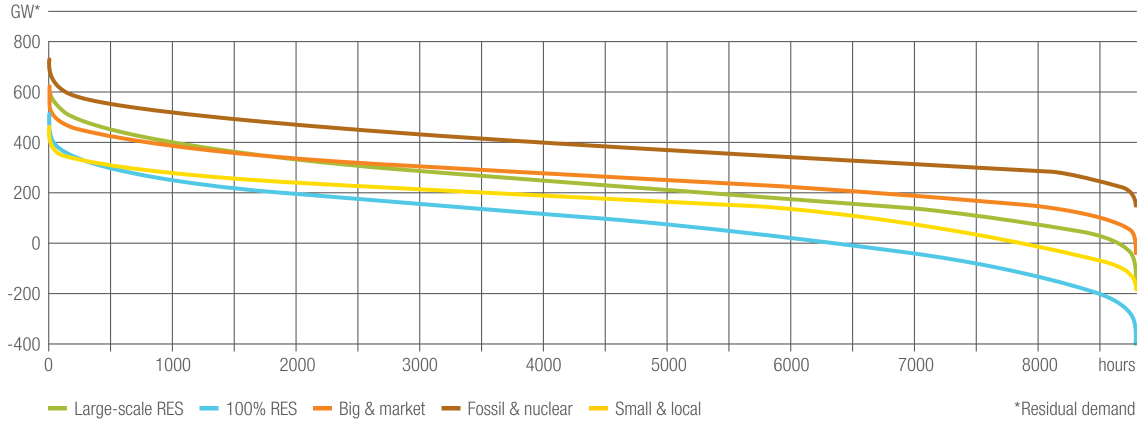


Figure 21: Duration curve of the residual demand in the different scenarios

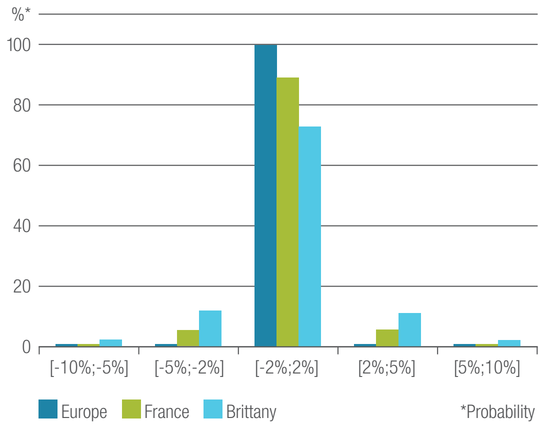


Figure 22: Hourly variation of the wind capacity factor

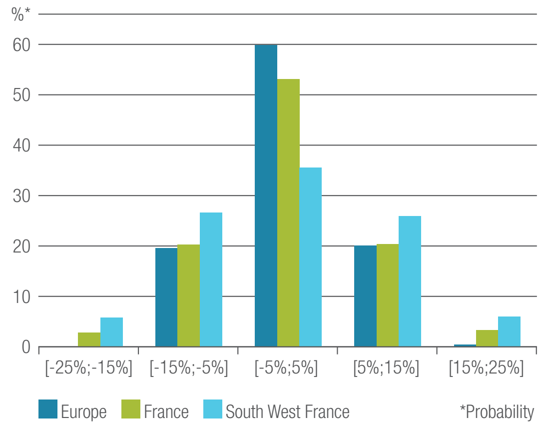


Figure 23: Hourly variation of the solar capacity factor (excluding night hours)

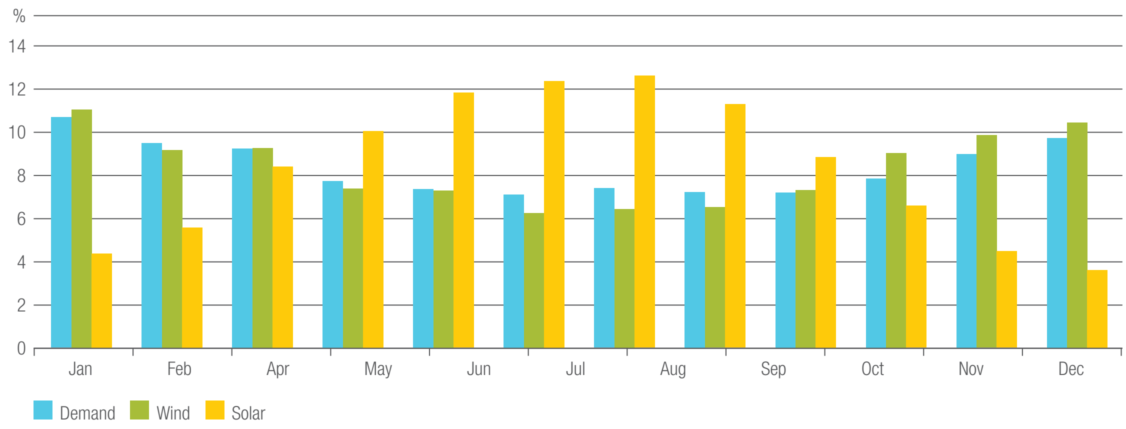


Figure 24: Monthly distribution of the solar and wind generations, and of the demand

By contrast, PV generation exhibits daily extreme variations which are almost synchronous in wide areas of Europe. As shown in Figure 23, hourly variations of 15 % of the capacity factor are common even at the European scale. As a result, dispatchable generation, storage and Demand Side Management have to cope with extreme variations every day. For example, in the scenario *100 % RES*, a gradient of the residual demand of +1.5 GW/min occurs regularly in the summer between 4 pm and 6 pm. In comparison, the maximal variation of the European demand over one hour in 2012 was +0.8 GW/min and it was then supported by more numerous traditional plants. Such gradients might become a technical challenge for some plants. Moreover, the actual short-term adequacy mechanism would probably need adaptations. Especially, the contribution of RES to ancillary services will become crucial.

Significant curtailment of PV generation

To a certain extent, PV generation can smoothen the residual demand, since it delivers energy during the day, when there is a significant demand. However, the extreme volumes of PV installed in the scenarios like *Small & local* or *100 % RES* lead to electricity generation around midday that can significantly exceed the demand. As can be seen in Figure 21, RES generation exceeds the demand 15 % and 30 % of the year under such scenarios. Indeed, it should be noticed that, in Europe, the seasonality of solar generation is not in line with the demand (Figure 24).

As a result, even with a hypothetic infinite network and with the significant amount of storage and DSM assumed in the scenarios, some renewable generation is curtailed in the scenarios with high shares of renewables especially due to PV generation (see Table 2 below). In this case, under the scenario *100 % RES*, the curtailment represents 8 % of the RES generation (average over one year).

	Large-scale RES	100 % RES	Small & local
Average annual curtailment (TWh)	38	208	55
Average annual curtailment (% of the wind and solar generation)	1.4 %	6.4 %	3.3 %

Table 2: RES curtailment with an infinite network

6 Outlook

The e-highway2050 consortium has developed new methodologies which allow the power system stakeholders and policy makers to anticipate the future transmission network development needs in line with the long term decarbonisation goals set at European level.

This methodology gives an initial, yet reliable, indication of the main challenges that transmission system operators will face.

A significant number of assumptions were necessary to perform the e-Highway2050 study. Even though the solid methodology and the consideration of various scenarios ensure the relevance of the results, further studies could for sure be performed with different assumptions. Some suggestions for these further studies are:

- More detailed studies with a closer time horizon before deciding any investment. Indeed, a profitable reinforcement in 2050 or even in 2040 may be useless before.

- A detailed study of the North Sea area which was simplified in the e-Highway2050 study

- Deeper assessment of alternative solutions to the expansion of the transmission grid

- The interactions with the gas network and the Power to Gas technology

For future studies, the e-Highway2050 results and methodologies can provide an excellent starting point. They will feed in the reflections on future releases of the TYNDP conducted by ENTSO-E.

The innovative methodologies applied to the core study of the project rely partially on expert assessment and could be further improved by more optimization-based approaches. The R&D part of the e-Highway2050 project has worked in parallel on this topic and developed promising prototypes (not described in this report, see deliverables D.8.xx). The proposed method requires massive computing power and formal well defined approximations which were assessed during the project. Further work on these optimization-based approaches will be required to make them available for TSOs in the coming years.

The operability of the European power system, as described in the e-Highway2050 scenarios, is a critical issue. Preliminary analyses were conducted within project but further research is essential to anticipate the upcoming challenges.

List of the deliverables

D 1.1 Review of useful studies, policies and codes

D 1.2 Structuring of uncertainties, options and boundary conditions for the implementation of EHS

D 2.1 Data sets of scenarios developed for 2050

D 2.2 European cluster model of the pan-European transmission grid

D 2.3 System simulations analysis and overlay-grid development

D 2.4 Contingency analyses of grid architectures and corrective measurements

D 3.1 Technology assessment from 2030 to 2050

D 3.2 Technology innovation needs

D 4.1 Operational validation of the grid reinforcements by 2050

D 4.2 Environmental validation of the grid reinforcements for 2050

D 4.3 Data sets of scenarios and intermediate grid architectures for 2040

D 4.4 Modular development plan

D 5.1 Roadmap for implementing the target governance model and an initial policy proposal

D 6.1 A comprehensive cost benefit approach for analysing pan-European transmission highways deployment

D 6.2 A toolbox supporting a pan-European technical evaluation of costs and benefits

D 6.3 Modular plan over 2020–2050 for the European transmission system

D 8.1 High-level definition of a new methodology for long-term grid planning

D 8.2 Enhanced methodology for demand/generation scenarios

D 8.3 Enhanced methodology to define optimal grid architectures for 2050

D 8.4 Enhanced methodology to define the optimal modular plan to reach 2050 grid architectures

D 8.5 Enhanced methodology to assess the robustness of a grid architecture

D 8.6 Detailed enhanced methodology for long-term grid planning

D 8.7 Recommendations about critical aspects in long-term planning methodologies

Glossary

CCS	Carbon Capture Storage
Cluster	Area/zone in Europe. Europe is splitted in around one hundred clusters for the e-Highway2050 study.
Curtailment	RES generation available but not used. Also called spillage or dump-energy.
DSM	Demand Side Management
EC	European Commission
Energy mix	Proportion of the different energy sources in the annual electricity generation
ENS	Energy not supplied due to lack of generation and/or grid congestions. Also called load curtailment or unsupplied demand.
ENTSO-E	European network of transmission system operators for electricity
Grid architecture	Set of transmission lines composed by the starting grid plus the reinforcements
GTC	Grid Transfer Capacity
HVAC	High Voltage Alternative Current
HVDC	High Voltage Direct Current
OHL	Over-Head-Lines
PE	Power Electronics
R&D	Research and Development
Reinforcement	New lines or upgraded existing ones
RES	Renewable Energy Sources
Starting grid	Grid considered as the starting point of the study. It is composed of existing lines plus those foreseen by 2030 in the TYNDP 2014.
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

Footnotes

1 European Commission, "Green paper A 2030 framework for climate and energy policies", COM(2013) 169 final, March 27 2013

2 European Commission "A Roadmap for moving to a competitive low carbon economy in 2050", COM(2011) 112 final, Brussels, 8.3.2011

3 European Commission, Communication "Energy Roadmap 2050", COM(2011) 885 final, Brussels, 15/12/2011

4 European Commission, "White Paper: Roadmap to a Single European Transport Area – Towards a competitive and resource efficient transport system", COM(2011) 144 final, Brussels, 28.3.2011

5 European Parliament Resolution on a Roadmap for moving to a competitive low carbon economy in 2050 http://www.europarl.europa.eu/sides/getDoc.do?type=TA&reference=P7-TA-2012 0086&language=EN&ring=A7-2012-0033

European Parliament Resolution on the White Paper on a Single European Transport Area http://www.europarl.europa.eu/sides/getDoc.do?type=TA&reference=P7-TA-2011- 0584&language=EN&ring=A7-2011-0425

European Parliament Resolution on the Energy Roadmap 2050, http://www.europarl.europa.eu/sides/getDoc.do?type=TA&reference=P7-TA-2013- 0088&language=EN&ring=A7-2013-0035

6 European Commission: "Achieving the 10 % Interconnection Target. Making Europe's electricity grid fit for 2020", COM(2015) 82 final, Brussels, 25.02.2015

7 Electricity Highways are defined as one of the 12 energy infrastructure priority corridors and areas in the Regulation on "Guidelines for trans-European energy infrastructures" (TEN-E regulation).

TEN-E regulation defines the Electricity Highway as "Any physical equipment designed to allow transport of electricity on the high and extra-high voltage level, in view of connecting large amounts of electricity generation or storage located in one or several Member States or third countries with large-scale electricity consumption in one or several other Member States".

ENTSO-E TSOs defined the Electricity Highway as follows: An Electricity Highway is any infrastructure designed to allow transport of electricity in view of connecting large amounts of generation or storage with large scale consumption crossing European regions.

In detail, an Electricity Highway:

– Would be AC, DC or hybrid technology, both on-shore and off-shore grid at extra high voltage level and would not be a precise standardised technology;

– Would enable a significant increase in the capacity to transmit electricity across Europe;

– Would be developed and integrated with the present electricity transmission infrastructure;

– Would involve a co-operation between control centres and the RSCI's going beyond today's implemented and envisaged processes;

– Would cover one or more Member States or Third Countries.

8 Albania, Austria, Bosnia and Herzegovina, Belgium, Bulgaria, Switzerland, Czech Republic, Germany, Denmark, Estonia, Spain, Finland, France, United-Kingdom, Greece, Croatia, Hungary, Ireland, Italy, Lithuania, Luxembourg, Latvia, Montenegro, FYROM, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Sweden, Slovenia, Slovakia.

9 The list of projects considered is not exactly the final one of the TYNDP 2014. Indeed, TYNDP 2014 was completed after the commencement of the e-Highway2050 project. The main discrepancies are given in the appendix of Deliverable 2.3.

10 https://antares.rte-france.com

11 This indicator does not give an idea of the amount of unsupplied demand. In the *Small & local* scenario, the related unsupplied demand is 5TWh in Europe.

12 Considering a typical OCGT investment cost of 0.7b €/GW plus fuel and CO_2 costs

13 Estimation based on the average solar/wind generation in Spain. This reasoning is based on average values and is thus extremely simplified, in reality, much more power would be required to cover periods with low solar/wind generation.

14 Estimation based on the average solar/wind generation in Spain. This reasoning is based on average values and is thus extremely simplified, in reality, much more power would be required to cover periods with low solar/wind generation.

15 Estimation made by the partners of the project.

16 The granularity of the technology perspective covers only the main technology families (each specific technology implementation requires detailed and local studies which are beyond the scope of the present project).

17 Technology option with a low maturity level (such as long distance superconducting cable) is not considered as an "available" technological option.

18 The capacity of HVAC XLPE underground cables is likely to stay in the range of 380 – 420kV with an increase above 1,8kA and transmitted power exceeding 1 250MW

19 HVDC underground cables could be installed over very long distances: it would improve public acceptance but permitting issues for large corridors would remain.

20 Interoperability of the HVDC systems (VSC converters for instance) will be a key issue.

21 No consideration of public acceptance or rights-of-way is made. Considerations are made only on the technological standpoint and focus mainly on the availability/maturity of the technology

22 These options have not been considered since suited for intra-cluster applications

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