*"Innovative **grid-impacting technologies** enabling a clean,*

efficient and secure electricity system in Europe"

Consolidation of the conclusions of the individual regional case studies

Deliverable 5.9

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Executive Summary

The main objective of the GridTech project is to conduct a fully integrated assessment of new grid-impacting technologies and their implementation into the European electricity system. This will allow comparing different technological options towards the exploitation of the full potential of future electricity production from renewable energy sources (RES-E), with the lowest possible total electricity system cost. The time frame of GridTech analyses is up to the year 2050, with a particular focus on the target years 2020, 2030 and 2050.

Under the project framework, regional analyses focusing on RES-E grid and market integration issues to be dealt with in seven target countries – Isle of Ireland, the Netherlands, Germany, Spain, Italy, Austria and Bulgaria – within different time horizons were carried out: (i) in the short-term (from 5 to 10 years' time horizon), analyses are focused on technologies that optimize the use of the existing transmission network and on the effects of these technologies on power system operation and integration of RES generation; (ii) in the long-term (target years 2030 and 2050), analyses are focused on innovative technologies implemented to integrate larger shares of RES generation.

In order to guarantee robust methodology implementation, critical discussion and review of preliminary results of regional case studies with regional target groups and stakeholders, a regional workshop was organized in each one of the seven target countries (Isle of Ireland, the Netherlands, Germany, Spain, Italy, Austria and Bulgaria). In several of regional events, important feedback was obtained from stakeholders – i.e. TSOs, policy makers, regulatory authorities, RES-E promoters and manufacturers – during the workshops. Suggestions regarding input data and sensitivity scenarios provided by invited experts were taken into account as much as possible into the regional studies.

The main technologies assessed in the regional analyses include: FACTS and DLR devices in the short term, DSM and storage options (mainly PHES, batteries and Electric Vehicles (EV), and HVDC in the mid- to the long-term. Results of these studies indicated that: (i) in the short-term, FACTS and DLR devices are cost-efficient solutions to increase the use of the existing transmission capacity; (ii) in the mid-term, solutions such to DSM, storage technologies and EV increase the system flexibility and can contribute to balance intermittency brought by larger amounts of RES production, reducing system operation costs; this benefit may be prolonged also in the longer term ; (iii) in the long-term, the development of a European overlay HVDC network could be an economic solution to better integrate countries with high percentage of RES and to achieve the European Commission's goal of reducing by 80 to 95 % CO_2 emissions by 2050

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Acronyms

ASC: Aluminium Stranded Conductor

CAES: Compressed air energy storage

DLR: Dynamic line rating

DSM: Demand-side management

DSO: Distribution system operator

ENTSO-E: European Network of Transmission System Operators for Electricity

EV: Electric vehicle

FACTS: Flexible AC Transmission Systems

HTLS: High Temperature Low Sag

HVAC: High-voltage alternating current

HVDC: High-voltage direct current

IEM: Internal Energy Market

NSE: Not supplied energy

OHL: Overhead lines

PHES: Pumped hydro energy storage

PST: Phase-shifting transformer

PV: Photovoltaic

RES-E: Renewable Energy Sources – Electricity

ROI: Return on Investment

RoR: Run-of-River

TSO: Transmission system operator

WP: Work Package

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1 Introduction

The major goal of GridTech is to conduct a fully integrated impact assessment of the implementation of innovative transmission network, bulk storage, and demand-side technologies into the European electricity system in order to exploit the full potential of RES generation across Europe, with lowest possible total electricity system cost. The time frame of GridTech analyses is up to the year 2050, with a particular focus on the target years 2020, 2030 and 2050.

For this purpose, pan-European scenarios for future RES generation, as well as for innovative grid-impacting technologies' implementation, have been defined for each target time-horizon (i.e. 2020, 2030 and 2050). The set-up of these scenarios has been based on the acquisition of a comprehensive set of reliable data. Taking into account these scenarios, two types of cost-benefit analyses for innovative transmission/storage/demand-side technology investments are carried out within the project:

- Top-down pan-European analyses (WP4), which enable the analyses of electricity flows in the meshed pan-European transmission grid, and the identification of inter-regional transmission bottlenecks identification and possible relief actions carried out in a transnational context, with the implementation of different innovative technologies.
- Bottom-up country-specific/regional analyses (WP5), which focus on the individual peculiarities of single electricity systems (i.e. a single European target country and its neighbouring systems).

The regional analyses carried out in WP5 of GridTech introduce the following novel aspects in relation to existing country-specific RES integration studies:

- The regional analyses focus on grid RES integration issues to be dealt in different time-horizons: (i) in the short-term (from 5 to 10 years' time horizon), analyses are focused on technologies that optimize the use of the existing transmission network and on the effects of these technologies on power system operation and integration of RES generation; (ii) in the long-term (target years 2030 and 2050), analyses are focused on innovative technologies implemented to integrate larger shares of RES generation.
- Analysis of the interdependences ("breathing") between a national electricity system and neighbouring ones that result from the use made of regional infrastructure assets (interconnection capacity and storage capacity).
- In-depth yearly analyses of the functioning of the targeted regional systems under extreme conditions (summer/winter, high/low load, high/low wind and/or PV generation, dry/wet hydro generation situation, etc.) occurring over shorter periods of time (from several hours to a few days) are conducted.
- Based on the above mentioned regional studies, cost-benefit analyses of grid-impacting technologies for different technology portfolios (available in each time-horizon) for each target country.

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The regional analyses were performed for seven selected countries:

- Isle of Ireland: high wind and other offshore generation potentials. Despite these potentials, the country faces the challenge of accommodating large amounts of RES production due to the lack of interconnection capacity with neighbouring countries and Continental Europe.
- The Netherlands: large potentials for both onshore and offshore wind generation. The country plays a relevant role in the design of the future offshore grid in the North Sea since it may became a major transit area crossed by large power flows coming from the North Sea to supply the load in Continental Europe.
- Germany: country with the highest wind and solar PV installed capacities in Europe. Such high amounts of RES production can have significant impacts in the national and trans-national grid.
- Spain: the country has one of the largest wind penetration shares in Europe and high potentials for solar generation and it may became an important transit country with power flows coming from North Africa to supply load in Europe. High penetration of RES generation added to weak interconnection capacity with the rest of Europe is likely to increase the demand for innovative grid-impacting technologies.
- Italy: high wind and solar potentials. While these potentials are located in the South of the country, demand is concentrated in the North, which leads to the need to transport significant amounts of power over long distances. Furthermore, as well as Spain, Italy may play an important role in interconnecting Europe and North Africa and the Western Balkan.
- Austria: high shares and potentials still to be deployed of pumped hydro storage, which can be operated in combination with large amounts of wind and solar generation to be installed in Northern and Southern Europe, respectively. Nevertheless, in order to enable this combined operation an adequate and sufficient development of the transmission grid is needed.
- Bulgaria: has high wind potential and considerable pumped storage capacity. This storage capacity is of strategic importance to balance generation intermittency in South-East Europe. For this purpose transmission interconnection capacity between Bulgaria and the other countries of the region is needed.

This report presents the main conclusions of the GridTech regional analyses performed for the seven selected countries. First, a brief description of each case is provided. After that, selected results from each case study are presented separately for each time-horizon (2020, 2030 and 2050). Finally, the main conclusions and policy recommendations are summarized.

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2 Brief description of the regional analyses

This chapter provides a brief description of the analyses performed for each selected country. The regional case studies focused mainly on the analysis of power system operation with and without considering a certain innovative technology. Through the use of unit commitment tools, system operation costs are calculated in both cases. For each time horizon studied (2020, 2030 and 2050), different generation mixes with increasing amounts of RES generation were considered as input data for each target country. Generation mixes and fuel and CO_2 emissions costs are the same as the ones used in WP4 simulations. Detailed input data and model descriptions for each case study can be found in the regional reports[1].

2.1 Isle of Ireland

In Figure 2.1, the geographic area of the Irish case study model is shown. The arrows on the border represent the boundary conditions provided as input by the pan-European analysis (WP4). The regional model aims at investigating into detail the need for reinforcements within the Irish transmission system. It is noteworthy that the model had to be extended to take into account in the analysis the following:

- The British strategy of onshore and offshore RES deployment and also in the Irish Sea;
- The possible Irish interconnection strategy to England and France;
- The neighbouring continental countries, i.e. Belgium and the Netherlands, which may further influence the Irish system, as well as the British and French grid developments and as a consequence the Irish interconnection strategy.

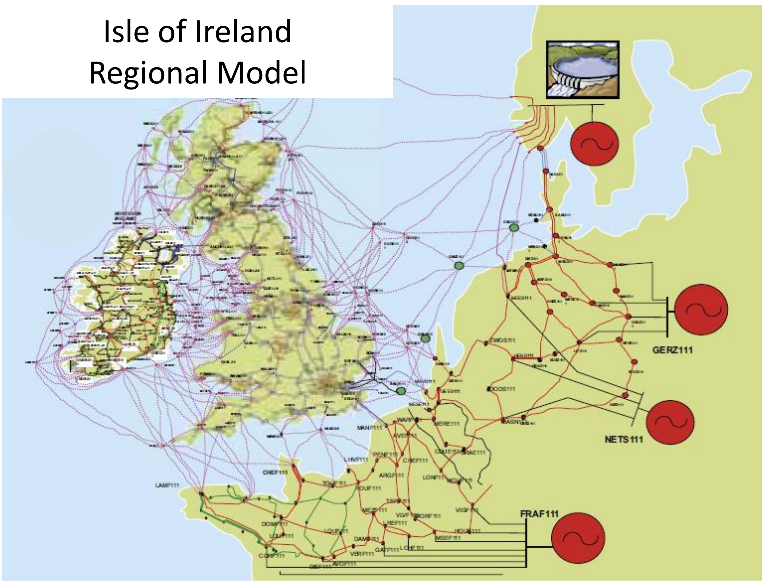

Figure 2.1: Case study of the Isle of Ireland.

[1] See: www.gridtech.eu

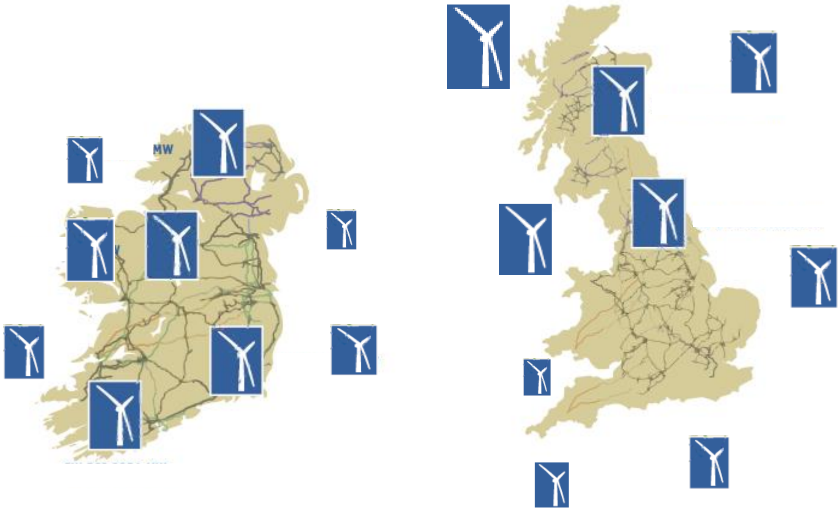

Figure 2.2: Wind Spatial Distribution

The British Transmission System has been modelled into detail based on a previous study (Norton et al., 2013). Input data has been downloaded from the National Grid web-site. Generation and load distribution data for 2016 were also available. Regarding the North of France, Belgium and the Netherlands, only the 400 kV transmission system has been modelled, based on geographic maps and information published by ENTSO-E and national TSOs.

The 2020 case is considered as the common starting point for the longer term (2030 and 2050) trajectories. It is expected that the deployment of technologies in this (short) time frame will not affect significantly the grid. The following is assumed for the 2020 base case scenario:

- Development of a Sea Water Storage (SWS) plant connected to Great Britain;
- Deployment of 800 MW of offshore generation in the Irish Sea;
- Reduced onshore wind deployment (about 60 % in Return on Investment (ROI) compared to what planned);
- No significant policies for the implementation of Demand Side Management (DSM) and Electric Vehicles (EVs).

The 2030 analyses consider three main technology scenarios (sensitivities with respect to these main cases are also assessed):

- 30 % penetration of DSM;
- 30 % penetration of EVs;
- Additional RES generation (RES+);

In the longer time frame (2050), multiple scenarios are assessed based mainly on higher penetration levels of DSM (40 % and 80 %) and EVs (40 % and 80 %), and other sea storage. Some of the assumptions considered in this time frame include:

- The increase of nuclear capacity in the UK from 14,000 MW to 28,000 MW;

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- The phase-out of Nuclear in France (installed capacity reduces from 40,000 MW to 14,740 MW);
- Additional solar and offshore wind deployment in France (20,000 MW and 41,000 MW, respectively);
- All Islands with 5 generators installed without must-run constraints;
- A moderate RES deployment offshore generation in the East (1,950 MW);
- Annual load in All Islands increases to 46.72 TWh.
- Additional RES generation (RES+): offshore wind in the West, wave and deep water wind generation in the North and the South, up to 4,000 MW in each location and up to 5,000 MW in the East.
- Extra SWS and pumped hydro energy storage (PHES) plants have been assumed with connection to Isle of Ireland.

More details about the Irish case study can be found in (Mansoldo, 2015).

2.2 Netherlands

The Dutch case study focuses on the possibilities of transporting large amounts of offshore wind power located in the West coast to the East side of the country via the onshore transmission network. Currently, the 380 kV network consists of a meshed AC network with a main ring structure in the centre of the country, as shown in the left side of Figure 2.3. The red line in the right side of the figure shows the corridor which is limits the West (Randstad area) – East (rest of the Netherlands) flow.

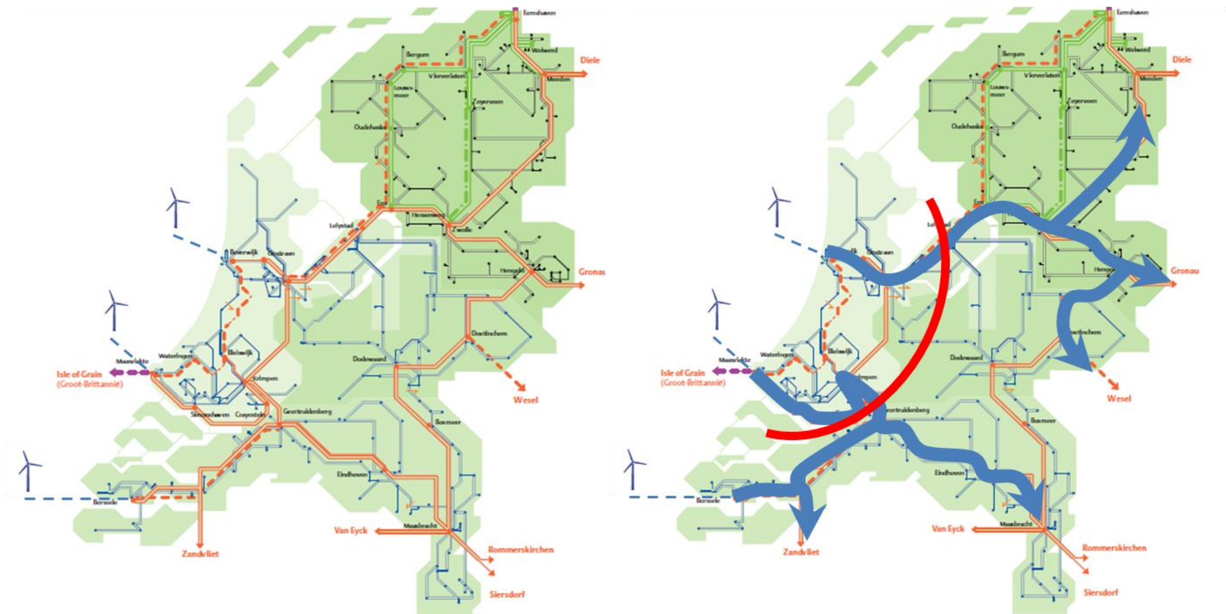

Figure 2.3: Dutch 380 kV network.

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The 2020 analysis assesses the cost and benefits of increasing transmission capacity of the above-mentioned corridor by (i) upgrading the existing congested grid and (ii) implementing Dynamic Line Rating (DLR) in this grid. These solutions are compared to a base case scenario without considering these options for increasing transfer capacity. Benefits are assessed in terms of avoided congestions, i.e. avoided wind curtailment/out-of-merit generation dispatch. In the 2030 horizon, apart from assessing the options of upgrading existing lines and installing DLR devices, the option of adding a new corridor is also evaluated. Both HVAC and HVDC options are analysed. For the target year 2050, a qualitative assessment focusing on the developments of the European energy policy and the possible effects on the transmission network and storage systems is provided.

More details about the Dutch case study can be found in (Van Houtert et al., 2015).

2.3 Germany

The German case study focuses on the interconnection of the wind-dominated northern part of country and the solar-dominated south by HVDC lines. Connecting these power areas with HVDC lines will allow supplying the whole country with RES power depending on weather conditions. The German transmission grid is divided in four zones operated by four TSOs: 50Hertz, Amprion, TenneT, and TransnetBW. Since public grid data is not available due to confidentiality reasons, the area of analysis is limited to the south-west of Germany (transmission system of TransnetBW, partner of GridTech). Therefore, for the purpose of GridTech analyses, Germany is split into two: the TransnetBW system (DE2) and the remaining system (DE1). Figure 2.4 shows the four German transmission system areas (left side of the figure) and the area of study of GridTech analyses (right side of the figure), which include interconnections to neighbouring countries (France, Switzerland and Austria).

Figure 2.4: German TSOs and area of study.

The control zone of DE2 is highly affected by the North-South power flows, triggered by wind energy located in the North of country. The underlying scenario on the way from 2020 to

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2050 is the step by step connection of wind-dominated North and the solar-dominated South with up to four HVDC corridors. The TransnetBW area will be connected to two of these corridors. In GridTech analyses the HVDC solution is compared with other grid extension alternatives. DLR and flexible AC transmission systems (FACTS) devices are assessed in all time horizons (2020, 2030 and 2050).

More details about the German case study can be found in (Burgholzer and Heyder, 2015).

2.4 Spain

The analyses performed for the Spanish system focuses on different solutions to deal with RES integration issues in the different time horizons, i.e. 2020, 2030 and 2050, and are briefly described below:

- 2020: Use of technologies that allow a higher use of the existing transmission grid without jeopardizing system reliability, such as Flexible AC Transmission Systems (FACTS) devices. In this analysis, the FACTS technology studied refers to a device that re-directs power flows from congested lines to parallel corridors with available capacity (power flow control device). By avoiding or reducing local grid congestions, the device contributes RES generation integration. More specifically, the 2020 study focuses on the installation of the FACTS device in the Southern Spanish transmission network to facilitate integration of RES power coming from Morocco, assuming a significant deployment of RES generation in North Africa by 2020. Since the analysis is focused on installation of a single FACTS device to avoid local grid constraints in the network area close to the interconnection with Morocco, it is assumed that power flows in the remaining interconnections are not affected.
- 2030: Use of innovative technologies, such DSM and storage, to integrate higher amounts of RES generation and avoid significant RES generation curtailment. More specifically, compressed air energy storage (CAES) and load-shifting are separately analysed. Since these technologies are considered to be implemented at the whole Spanish system level and the amounts of RES production integrated are expected to be higher than in the 2020 horizon study, the effects on interconnection power flows can be significant. Therefore, for the 2050 horizon, both the Spanish and the French systems are modelled.
- 2050: In the long-term, massive amounts of RES generation are expected to be deployed. As uncertainties related to grid developments and integration solutions are significantly higher than in the above-mentioned time horizons, two alternative types of solutions are analysed in the 2050 study: the first one considers the development of an HVDC supergrid to bring RES electricity from North Africa to Europe, which is based on the DESERTEC vision[2]; the second one focus one “local” or country level solutions such as DSM and electric vehicles to integrate RES generation.

[2] www.dii-eumena.com

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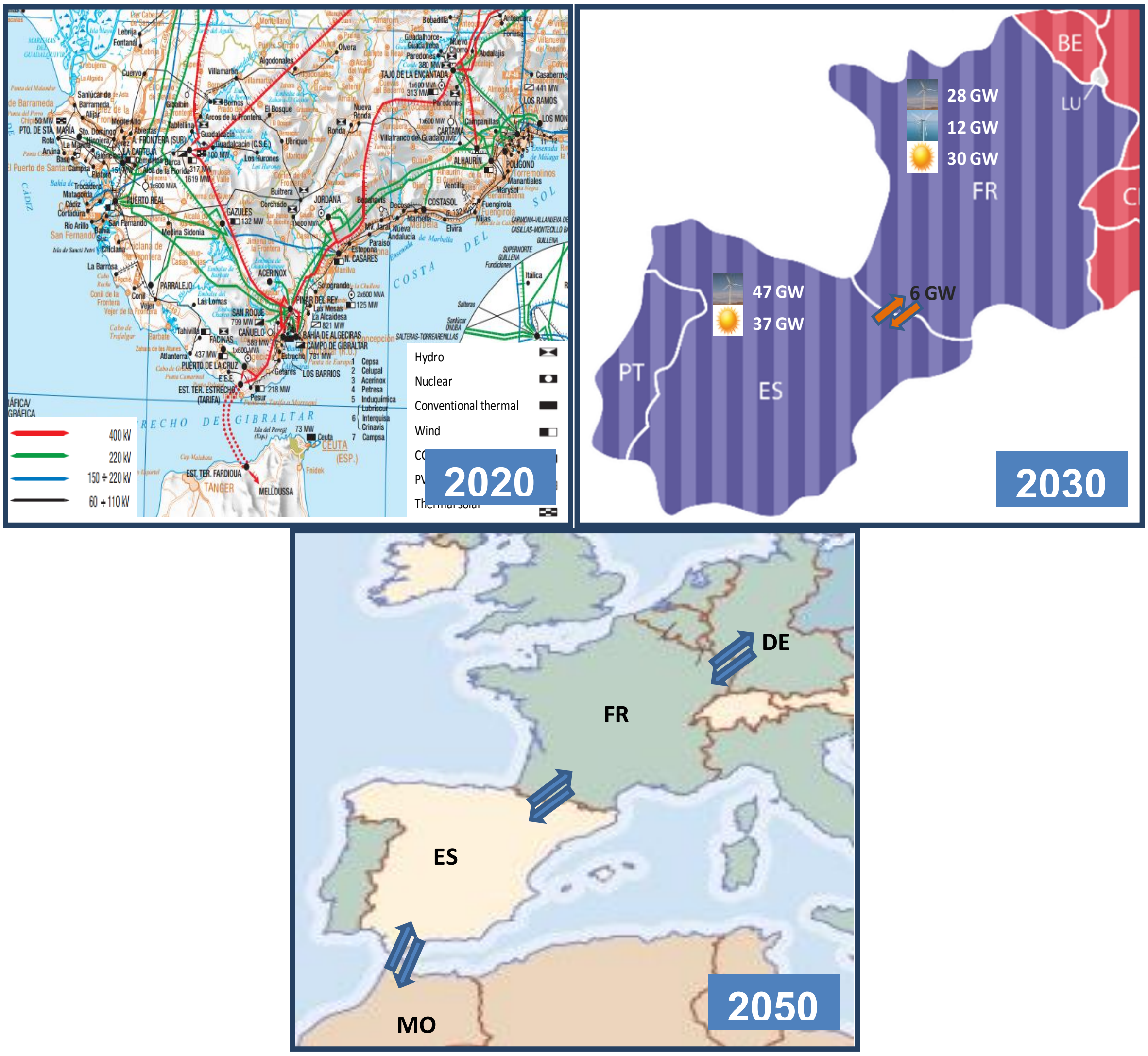

Figure 2.5: Spanish case area of study in the different time horizons.

Figure 2.5 shows, for each time horizon, the area considered for Spanish case study analyses. More details about the Spanish case study can be found in (Fernandes et al., 2015).

2.5 Italy

Over the past years, a great amount of RES generation capacity, especially PV and wind power, has been installed in Italy. The fact that a significant share of this capacity is installed in the South, while load is located mainly in the central and the northern parts of the country, has considerably increased grid congestions and RES curtailment. In addition, the geographical location of Italy predisposes the country to be an electricity hub in the Mediterranean Sea, and it may act as a transit country for power flows coming from North Africa and from South-East Europe (Figure 2.6).

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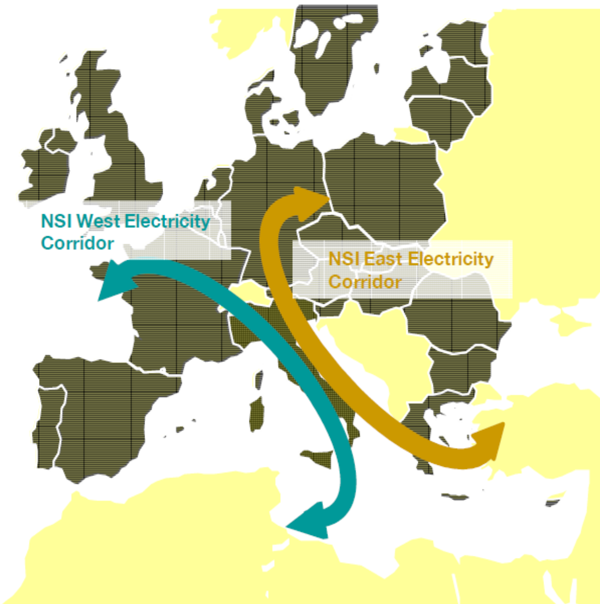

Figure 2.6: Priority energy corridors defined by Regulation 347/2013 involving Italy.

As a result of grid congestions within the country, the Italian market is divided into several market zones. For the purpose of GridTech analyses, the Italian power system has been modelled accordingly (Figure 2.7).

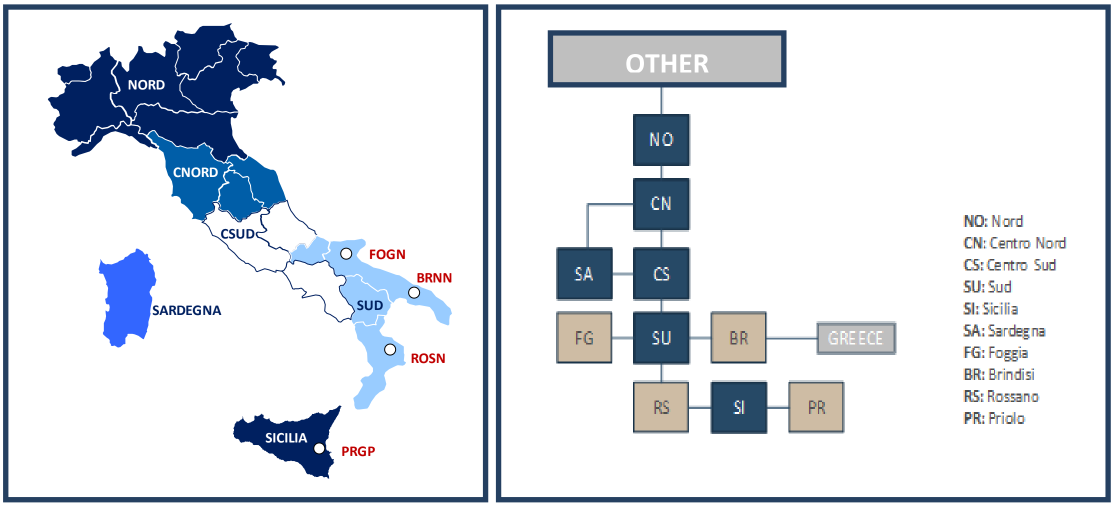

Figure 2.7: Italian market zones and nodes representation for the regional case study.

The analyses performed for the Italian case study focus on different solutions to deal with RES integration issues in the different time horizons, 2020, 2030 and 2050 as briefly described below:

- 2020: in the short term the new HVDC interconnection Italy-France (Piossasco-Grand'Ile, through the Frejus motorway tunnel) is assessed. This interconnection is a PCI project included in TYNDP 2014. This project includes the removal of grid constraints on the current 380 kV Italian transmission grid. The project favours market integration, as well as the use of the most efficient generation capacity. In addition, the project can

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contribute to RES integration in the European interconnected system by improving cross border exchanges. Such benefits are ensured within different future scenarios.

- 2030: In this time horizon, the installation of Dynamic Line Rating, Phase Shifter Transformers, and new HVAC and HVDC lines, are studied.
- 2050: In this scenario, massive amounts of RES generation are expected to be deployed and the uncertainties related to grid developments and integration solutions are significantly higher. For this reason, different technologies are analysed and compared, including HVDC interconnections between Italian market zones, pumped storage (PHES) and demand response (DSM).

The assessment of these technologies was carried out through the use of the model MTSIM (Medium Term SIMulator), developed by the project-partner RSE. This tool represents zonal electricity markets, considering DC optimal power flow. The model determines the hourly market clearing over a yearly time horizon by minimizing operation costs, including the costs of load shedding and energy curtailment. Input data, methodologies, results and conclusions obtained from the Italian regional case study are presented in detail in (D'Addese et al., 2015).

2.6 Austria

The analyses performed for the Austrian case study for each time horizon are the following ones:

- 2020: in the short-term, it is important to extend the interconnection to Germany, due to high import expectations from Germany. Therefore, the expansion of the transmission power line in Salzburg is necessary to connect the imports with the high PHES capacities in the Alps. Furthermore, the extension in Salzburg is of high interest for closing the so-called “380 kV HVAC transmission ring” (see area A in Figure 2.8) in Austria, which is necessary for guaranteeing sufficient security and reliability of supply. In addition, the interconnection to Italy will also be extended.
- 2030: within this time horizon, the main focus of analysis is the final closing of the 380 kV circuit in Austria, whereby the last missing part is located in the south, in Carinthia (see area C in Figure 2.8). Furthermore, the expansion of the transmission power line (TPL) in Tirol, which forms a bottleneck between western and eastern Tirol, will also be analysed. In comparison, a general flexibility via DLR and FACTS is analysed separately and also in combination.
- 2050: in the long-term, a RES-E share of 64 % is assumed for Austria; especially the increase of wind and PV capacity is significant. Therefore, in order to provide more flexibility in the transmission system one focus will be to analyse the impact of DLR and FACTS. The second emphasis is set on the extension of PHES capacities (turbine as well as pumping capacity). This could provide to neighbouring countries, e.g. Germany, more flexible generation and additional storage potentials. Furthermore, the impact of high/low annual production of Run-of-River (RoR) plants is analysed. Finally, the focus of analyses is set on the first interconnection to Slovakia, a 2 GW HVDC line.

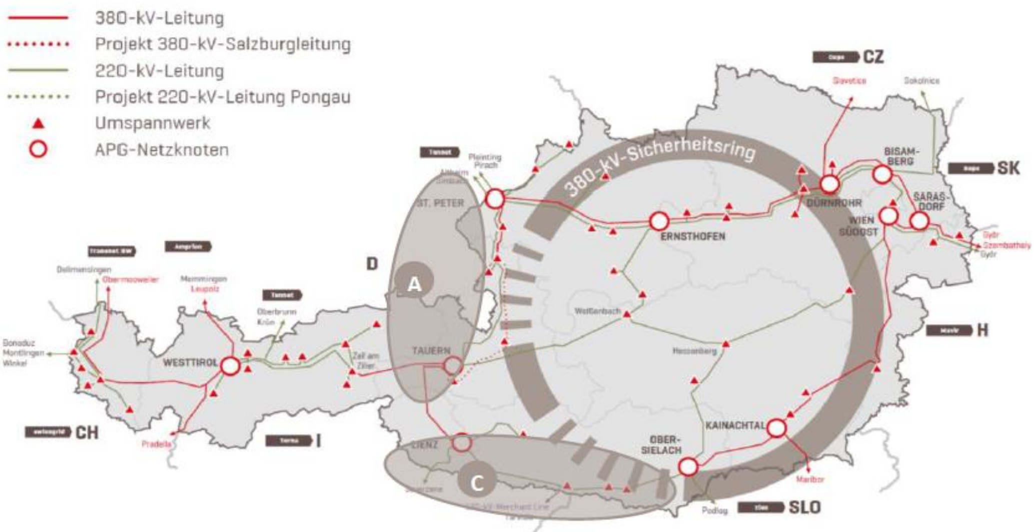

Figure 2.8: Austrian transmission grid

More details about the Austrian case study can be found in (Burgholzer et al., 2015).

2.7 Bulgaria

The Bulgarian case study mainly focuses on the development of the transmission grid, especially in the North-East of Bulgaria where wind power plants are located, and on the increase of storage capacity. More specifically, the technologies analysed in the different time-horizons are the following ones:

- 2020: increase of transmission capacity in the North-East of Bulgaria by building new transmission lines using either conventional Aluminum Stranded Conductor (ASC) with DLR devices or High temperature Low Sag (HTLS) conductors; increase of PHES storage capacity by enlarging down reservoir “Yadenitsa” of existing PHES “Chaira”.
- 2030: further increase of transmission capacity in the North-East of Bulgaria by building new transmission lines using either conventional Aluminum Stranded Conductor (ASC) with DLR devices or HTLS conductors; construction of new PHES (148 MW); introduction of EVs (2 % of penetration - 35,000 vehicles); and implementation of DSM (from 20 MW to 100 MW, depending on price signals).
- 2050: 10% penetration level of EVs in the total number of vehicles in Bulgaria (180,000 EVs); increase of DSM participation (from 120 MW to 225 MW, depending on price signals); and 2 % storage/battery penetration level of the total demand connected to the distribution grid.

More details about the Bulgarian case study can be found in (Andreev et al., 2015).

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3 2020 Analyses: selected results

3.1 Isle of Ireland

Figure 3.1 shows the grid expansion results for the base case, i.e. the case with the Sea Storage (SWS) project connected to Great Britain (LCHP_SWS_GB), and the case with the SWS connected to All Islands (LCHP_SWS_AI). It was assumed that all ongoing major projects regarding the 400 kV transmission grid are in service in the 2020 scenario. No further internal reinforcement have been proposed by the model. On the other hand, several interconnections have been also introduced with similarities and strategies between the two cases.

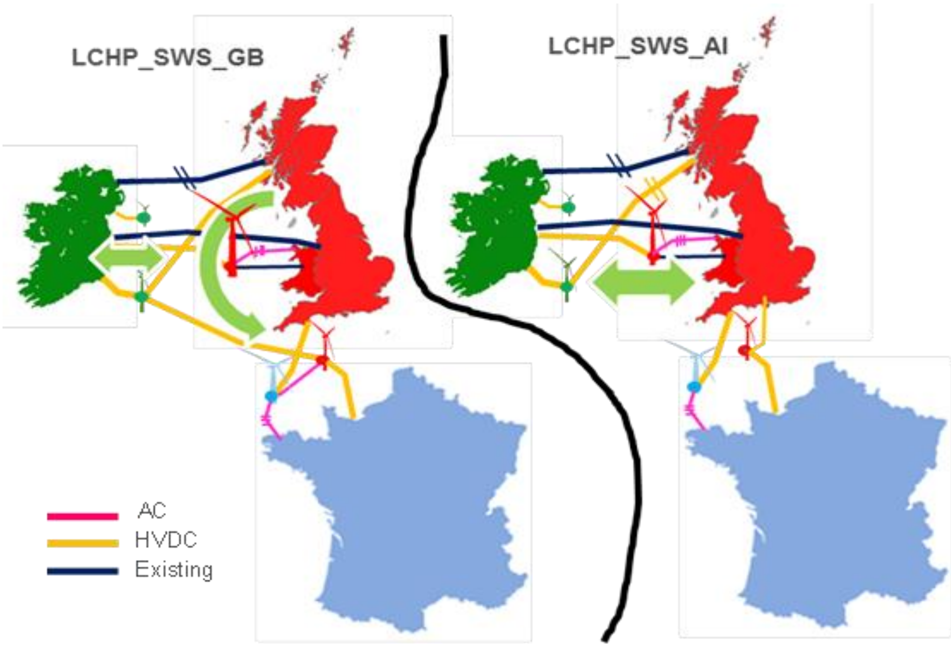

Figure 3.1: Irish case study – grid expansion results for the Base case (left) and sensitivity on the Sea Storage project (right).

In the base case, the model results show a balanced offshore solution centralized in the Irish Sea with the Irish jurisdiction as an offshore hub. It is worth noticing that an offshore corridor connecting Scotland to Britain and then France has been proposed. This solution has many functions, which include:

- To by-pass internal congestions in Scotland and Britain.
- To facilitate transfer of power between England, France and the Isle of Ireland.
- To connect several offshore projects in the three jurisdictions.

When the SWS project is assumed to be connected to All Islands, a more northwards development strategy is proposed with a major focus on energy exchange between the Isle of Ireland, England and Scotland. An effective meshed offshore grid has been structured with two offshore central hubs located in the Irish and British jurisdictions.

In terms of techno-economic performances, the grid expansion solution is reduced in terms of length and investments (power flows over shorter distances and imports are slightly

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increased) when the SWS is connected to All Islands. In this case, the yearly net load in Ireland is increased to the SWS efficiency, increasing imports.

Savings in terms of operation costs in Ireland (31 M€/y) are compensated the net demand increase, which reduces exports income by 43 M€/y. Finally, the reduced investment costs in comparison with the base case scenario (30 M€/y) results in savings of 18 M€/y (i.e. 1% of the total costs). These results are shown in

.

Table 3.1: 2020 Economic Analysis

	Production	CO2	Load Shed.	Loss of prod.	Total Operation	Import/Export	Investments	Grand Total
	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]
2020_BASECASE	738	143	0	0	880	741	223	1844
2020_LCHP_AI	711	138	0	0	849	785	192	1826
						Savings AI vs GB	[M€]	**18.3**

3.2 Netherlands

For the Dutch 2020 horizon case study, a market model simulation is used to determine the yearly economic dispatch for three different scenarios: (i) Base case: current 380 kV network in the Netherlands with actual transmission capacity of 3,000 A; (ii) Case A-2020: implementation of DLR in the 380 kV central ring, which, depending on weather conditions can reach a maximum capacity of 4,000 A (actual transmission capacity without DLR is equal to 3,000 A); (iii) Case B-2020: Upgrading of existing lines to increase actual transmission capacity to 4,000 A. The investment costs considered for the cases A and B are 1 M€ for the implementation of DLR in a double circuit line and 1.3 M€/km for line upgrading.

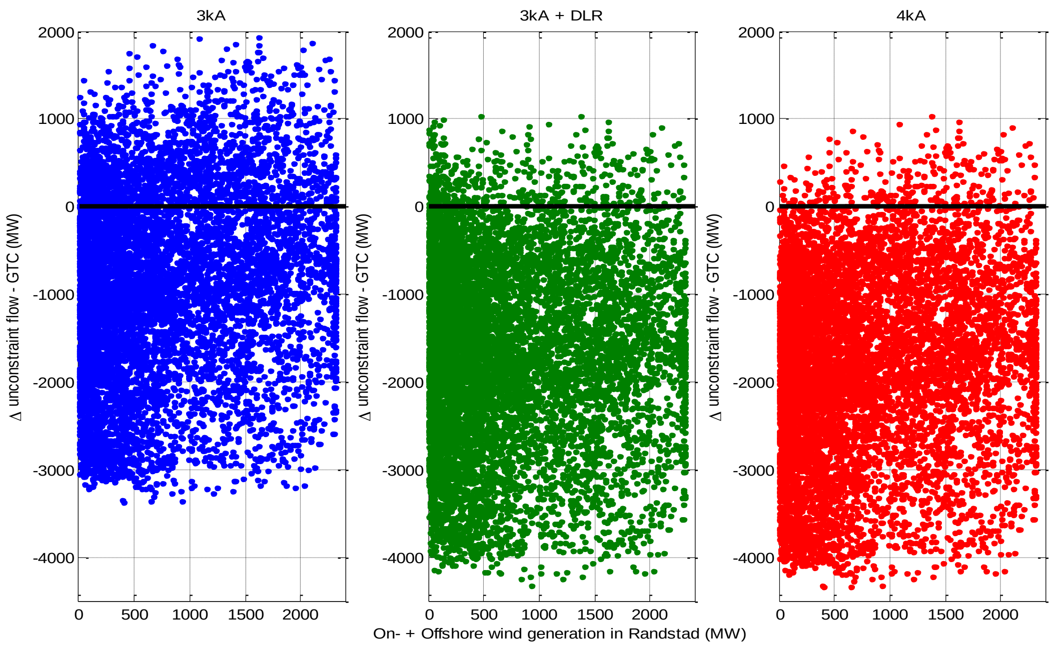

Figure 3.2: Dutch case study – correlation between wind generation and grid transfer capacity

Figure 3.2 shows total wind generation in the West coast versus the available transfer capacity between the Western and the Eastern areas. The positive values in the figure correspond to hours with grid congestion, i.e. hours when the flow from the market model is larger than the available transmission capacity. It can be observed that the number of congested hours is reduced largely in cases A and B. Table 3.2 summarizes the main results from the model and annualized investment costs. Investment costs shown consider that assets have a life-time of 40 years. Wind curtailment is evaluated at the system marginal cost.

It can be observed in Table 3.2 that the value of curtailed wind is reduced by 25 and 26 €/year in the A-2020 and B-2020 scenarios, respectively, in respect with the base case scenario. According to these results, for relative low levels of congestions DLR has a better cost-benefit relation when compared to expanding transmission capacity. In the studied cases, there is a strong relation between large amounts of wind power and the cooling of overhead lines by wind. However, it must be kept in mind that if a large amount of power (non-wind related RES or conventional power) has to be transported during periods with low wind speeds, DLR is less effective and the upgrade of lines will be the preferable solution to increase the grid transfer capacity.

Table 3.2: Dutch case study - 2020 results for the different scenarios *versus* annualized investment costs

Case	Number of congested hours	Total energy above GTC limit	Total curtailed wind energy	Value of curtailed wind	Remaining congestion	Cost of investment
	hours	GWh	GWh (% of total wind energy)	M€	GWh	M€
Base ('3kA')	1972	1018	801 (12%)	29	218	0
A-2020 ('DLR')	457	140	103 (2%)	4	36	0,2
B-2020 ('4kA')	277	80	77 (1%)	3	3	12,3

3.3 Germany

For the 2020 horizon, four cases are compared: (i) 2020A - base case with transmission capacity planned for 2020; (ii) 2020B - introduction of phase shifters transformers (PSTs) with a phase angle smaller or equal |30|°; (iii) 2020C – implementation of DLR, modeled as increased transmission capacity depending on wind speeds; (iv) 2020D – implementation of PSTs and DLR. The market model used to simulate generation dispatch in Germany takes into account all the nodes of the TransnetBW grid (DE2), as well as the interconnections with neighbouring countries/areas (i.e. France, Switzerland, Austria, and DE1).

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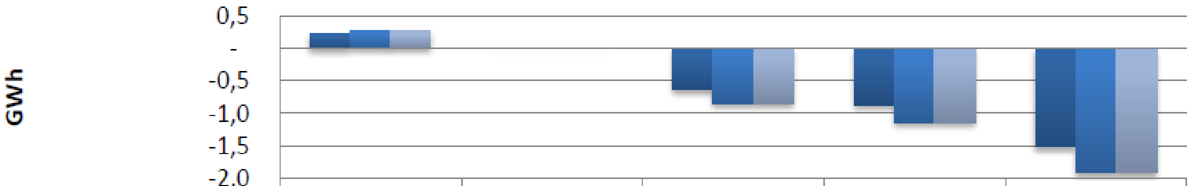

	∑ RES generation	hydro generation	turb generation	pump consumption	thermal generation
Difference B-A (GWh)	0,2	-	-0,6	-0,9	-1,5
Difference C-A (GWh)	0,3	-	-0,8	-1,1	-1,9
Difference D-A (GWh)	0,3	-	-0,8	-1,1	-1,9

Figure 3.3: German case study - 2020 results for the different scenarios in comparison with the base case

Figure 3.3 presents the total annual differences in the generation structure the analysed scenarios for 2020 with respect to the base case scenario (2020A). According to the results, differences with respect to the base case scenario are relatively low. This can be explained by the fact that for 2020 nearly 50 % of the annual demand is covered by thermal power plants (coal and nuclear). The changes caused by the implementation of DLR and PSTs slightly reduce wholesale prices during some hours, as shown in Figure 3.4. The average price can be reduced by 0.75 €/MWh when PSTs and DLR are implemented.

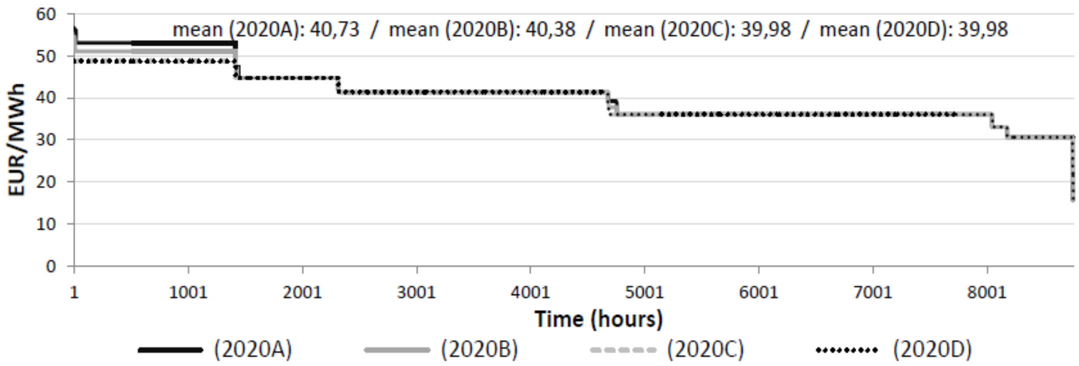

Figure 3.4: German case study - 2020 price duration curves.

3.4 Spain

For the 2020 horizon study, the impact assessment of the FACTS device was performed in two steps: first, a tool to perform power flow analyses (PSS-E) was used to compute the additional RES power imported from Morocco integrated thanks to the FACTS device; after that, a unit commitment tool (ROM model) was used to calculate yearly generation dispatch in Spain taking into account the additional RES generation imported from Morocco.

Table 3.3 presents the aggregated results for the simulations run in PSS/E. It can be seen that in scenarios of high load in Andalusia (i.e. demand higher than 85 % of the peak load in this region) together with high RES generation (from 40 % to 70 % of the total RES installed capacity) the device cannot alleviate overloads in the studied area. Therefore, during these hours no additional RES can be imported. It is also observed that in scenarios of high demand the device contributes to relatively low additional RES imports. The scenarios for

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which higher levels of RES can be imported are the ones of plateau demand. In these scenarios, RES imports were initially limited by overloads in the studied area. With the device, flows in overloaded lines can be re-directed to partially loaded lines. Finally, for scenarios of low demand the device does not contribute to additional RES imports since no congestions were detected.

Table 3.3: Spanish case study - Additional RES imports in 2020 due to the installation of the FACTS device

Scenarios (only for hours with RES imports = 3,013)			Results
Demand in Andalusia	**RES generation in Andalusia**	**Number of hours**	**Additional hourly RES imports (MW)**
Peak (>0.85 p.u.)	High (0.4-0.7 p.u.)	10	0
Peak	Average (0.2-0.4 p.u.)	7	0-100
Peak	Low (0.13-0.2 p.u.)	194	100-200
Plateau (0.65-0.85 p.u.)	High	47	200-400
Plateau	Average	284	400-500
Plateau	Low	589	500-600
Valley (<0.65 p.u.)	Low/Average	1,882	0

Comparing the results of the ROM model for the base and the FACTS scenarios, the additional RES generation corresponds to 0.4 % of the total RES production in the base case and the reduced thermal production corresponds to 0.3 % of the total thermal production in the base case. This additional RES production increases the use of pumped-storage units (1.1 % in relation to the base scenario), which does not avoid some RES curtailment.

According to the ROM model results, the modifications introduced by the higher penetration of RES generation into power system operation provoke a reduction in operation costs of approximately 30 M€/year, while the investment cost of the FACTS device was estimated at, approximately, 4.3 M€. The investment cost of the FACTS device installed under the Twenties project framework in Spain was estimated at, approximately, 4.3 M€ (García-González, 2013). According to these values, the device's cost is more than compensated by the operation costs savings obtained from the ROM model. In this respect, it is worth mentioning that, in this analysis, it is assumed that RES generators have zero operation costs. Therefore, it is considered that Spain imports RES generation from Morocco at 0 €/MWh. In this sense, operation costs savings computed in this study can be overestimated.

On the other hand, other benefits of FACTS devices are not taken into account in this analysis, such as much shorter construction times when compared to a new transmission line. In this respect, FACTS can reduce or avoid transmission constraints in highly congested areas when permitting procedures and construction times of new transmission lines are delayed. In less congested areas, FACTS devices can be an economic solution to avoid congestions, and consequently redispatch measures and/or RES curtailment.

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3.5 Italy

The 2020 analysis for the Italian case study focused on increasing the Italian system interconnection capacity by building a new HVDC link (1200 MW) between Italy and France (study case B). In order to assess the benefits of this additional interconnection capacity in terms of reduced network congestions and curtailment of RES generation, a base case (study case A) without the interconnection was also analysed.

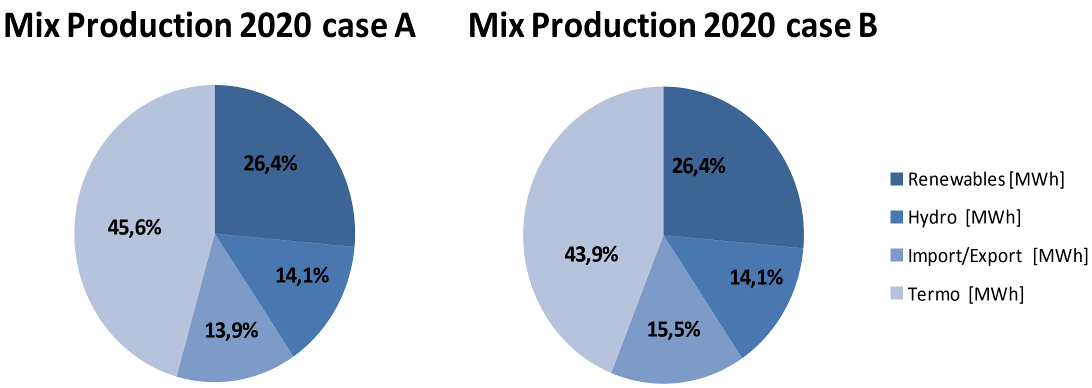

Figure 3.5: Italian case study - Generation mix resulting from scenarios A (without HVDC link) and B (with HVDC link)

As a result of the new HVDC interconnection transmission line to France, there was an increase of import/export balances at the expense of thermoelectric production and a reduction of approximately 2 % of CO_2 emissions. Regarding thermal generation, it is worth highlighting that the most expensive gas units are replaced by cheaper coal power plants.

The analyses conducted assumed a cost of CO_2 equal to 10 €/ton. Savings for the electricity system operation were estimated in 120 M€/year. Sensitivity analyses showed that savings for the electricity system are increased if the CO_2 certificate price is higher. Conclusions pointed out to the fact that the Italy-France interconnection project would allow a more efficient generation dispatch (i.e. reduced costs of energy supply) and increased system security in both countries.

3.6 Austria

The market model used to simulate generation dispatch for the Austrian case study considers 17 nodes representing the main substations within Austria, plus seven neighbouring nodes (i.e. DE1, DE2, Czech Republic, Hungary, Slovenia, Italy and Switzerland). For the 2020 horizon, the model is run for two scenarios: (i) 2020A (base case) – without Salzburg transmission line; and, (ii) 2020B – with Salzburg transmission line. Figure 3.6 presents the total annual differences between cases 2020A and 2020B for the whole Austrian electricity system.

As a result of the expansion of the Salzburg transmission line, there is a slight increase in RES generation and a considerable increase in the use of pumping units. It is observed that thermal generation also increases. Regarding this, it is worth mentioning that more expensive gas units are replaced by cheaper coal-fired plants. As a consequence of this new generation dispatch, the annual generation costs are reduced by 0.64 % (i.e. by 2.1 M€/year).

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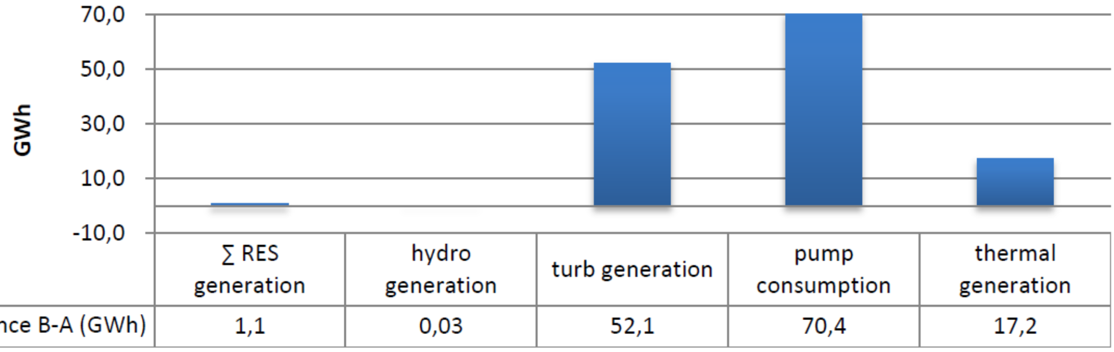

Figure 3.6: Austrian case study - Results for the 2020 horizon

3.7 Bulgaria

The Bulgarian 2020 case study focuses on the expansion of transmission capacity in the North-East of the country and on increased PHES capacity by enlarging the down reservoir “Yadenitsa” of existing PHES “Chaira”. Yearly generation dispatch was analysed for: i) the base case scenario without PHES and without grid expansion; ii) base case scenario + added PHES; iii) base case scenario + grid expansion. Regarding case (ii), it is assumed that the installed capacity of PHES “Chaira” is not changed, but the implementation of this project increases the down reservoir accumulation volume by 9 million m^3. In case (iii) it is assumed that two double circuit 110 kV lines are built to increase the North-East transmission capacity using innovative technologies (either conventional aluminium steel conductors with installed DLR devices or HTLS conductors). The results from the simulations are shown in Table 3.4.

The annualized investment cost of increasing the down reservoir capacity of PHES “Chaira” was estimated at 4.226 M€/year, assuming an interest rate of 7 % per year and the storage’s useful life equal to 75 years. The annualized investment cost of the two double circuit lines with a total transfer capacity of 1,000 MW and 60 km of length was estimated at approximately 1.5 M€/year, assuming an interest rate equal to 7 % and the lines’ useful life equal to 50 years.

Table 3.4: Bulgarian case study - Results for the 2020 horizon

TWh	I: Base case	II: Added PHES	III: Grid expansion	II-I	III-I
Nuclear	15.94	15.94	15.94	0.00	0.00
Thermal	17.95	17.68	17.58	-0.27	-0.38
Conventional hydro (including PHES generation)	3.02	3.29	3.05	0.27	0.04
RES generation	5.44	6.22	5.95	0.39	0.39
Demand	41.57	41.57	41.57	0.00	0.00
PHES consumption	0.59	0.98	0.65	0.39	0.05
RES	0.00	0.39	0.12	0.39	0.12
Thermal cost (M€)	685.99	678.62	675.88	-7.37	-10.11

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Although PHES capacity is not increased in scenario “Add PHES”, the project “Yadenitsa” contributes to a higher integration of RES generation. This is due to the fact that the larger accumulation volume capacity in the down reservoir “Chaira” facilitates the circulation of water volume between up and down reservoir, allowing the storage of higher amounts of wind production during off-peak hours to be used during peak hours, reducing system operation costs.

It is worth emphasizing that differences with WP4 results regarding the use of PHES capacity in Bulgaria are due to the fact that WP4 models the functioning of the of the European Internal Energy Market (IEM), while in this study only the Bulgarian is modelled. When the IEM is taken into account, RES intermittency is partially mitigated due to differences in production profiles. Furthermore, electricity prices tend to converge. This leads to a lower use of PHES. On the other hand, the simulations performed for the Bulgarian system with the “Resource Optimization”, power flows with neighbouring countries were not taken into account. In this case, there is a higher utilization of PHES to balance intermittent RES production. Therefore, the conclusions obtained here are valid for isolated power systems or power systems with low interconnection capacity (for example Cyprus), or for system where RES generation cannot be evacuated due to grid congestions. Finally, it important to take into account that generation dispatch in unit commitment models are based on operation costs, which are generally lower than market prices.

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4 2030 Analyses: selected results

4.1 Isle of Ireland

For the time horizon of 2030, eight scenarios have been assessed: (i) Base case 2030; (ii) DSM 30 %; (iii) EVs 30 %; (iv) DSM 30 % + EVs 30 %; (v) Sea storage connected to All Islands (LCHP_AI); (vi) Additional deployment of offshore generation in the North West of Ireland (RES+) + LCHP_AI; (vii) Additional deployment of offshore generation in the North West and South West of Ireland (RES+VERO) + LCHP_AI; and (viii) RES+VERO + Sea storage connected to Great Britain (LCHP_GB). Table 4.1 shows the summary of economic results for the 2030 scenarios.

DSM contributes largely to the reduction thermal generation and, consequently, the reduction of production costs. Load shifting allows a higher integration of renewable generation, which would have to be exported otherwise. It is also observed an increase in imports as a result of higher system flexibility, which allows obtaining lowest prices on the market outside the Isle of Ireland. This contributes to a further reduction of thermal generation. Similar thermal generation reduction is achieved only the RES+ scenarios.

Despite the fact that the introduction of EVs increases total load by 1.86 TWh, the economic benefits provided by this increased system flexibility compensate the costs related to the additional demand in relation to the base case scenario.

Table 4.1: 2030 Irish case study – summary economic results.

	Production	CO2	Load Shed.	Loss of prod.	Total Operation	Import/Export	Investments	Grand Total	NET Imp.(-)/Exp.(+)
	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]	[M€]	[TWh]
Basecase_2030	1497.6	289.6	0.0	1.5	1788.8	-568.9	270.0	1489.9	10.2
S0_2030_DSM30	255.8	63.1	0.0	0.0	318.9	188.0	200.0	707.0	-3.4
S0_2030_EV30	1435.4	277.6	0.0	100.0	1813.0	-480.8	121.8	1454.0	8.6
S0_2030_DSM30_EV30	1346.6	260.4	0.0	0.0	1607.0	-402.8	214.9	1419.2	7.2
S0_2030_LCHP_AI	1415.1	273.7	0.0	0.9	1689.7	-499.9	200.8	1390.6	9.0
RES+_2030_LCHP_AI	264.7	51.2	0.0	2.5	318.4	62.1	202.0	582.5	-1.1
RES+VERO_2030_LCHP_AI	205.8	39.8	0.0	22.5	268.1	-567.5	326.2	26.8	10.2
RES+VERO_2030_LCHP_GB	169.1	32.7	0.0	53.2	255.1	-518.5	309.2	45.8	9.3

Table 4.2 shows yearly savings obtained from the comparison between two case scenarios.

Table 4.2: Irish case study – 2030 scenarios comparisons

Comparison		Savings (+)
2030 DSM30 Vs. Basecase	[M€]/y	782.9
LCHP_AI Vs. GB	[M€]/y	99.3
2030_DSM30_EV30 Vs. Basecase	[M€]/y	70.7
2030 EV30 Vs. Basecase	[M€]/y	35.9
RES+AI Vs. RES+GB	[M€]/y	18.9

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4.2 Netherlands

For the 2030 horizon, six scenarios are compared: (i) Base case: current 380 kV network in the Netherlands with actual transmission capacity of 3,000 A; (ii) Case A-2030: application of DLR to the 380 kV central ring with a maximum capacity of 4,000 A, depending on weather conditions (actual transmission capacity without DLR is equal to 3,000 A); (iii) Case B-2030: Upgrading of existing lines to increase actual transmission capacity to 4,000 A; (iv) Case C-2030: Upgrading if existing lines to 4,000 A + new 4,000 A HVAC line; (v) Case D-2030: Upgrading of existing lines to 4,000 A + new 1,000 MW HVDC line; and (vi) E-2030: Upgrade of existing lines to 4,000 A + new 2,000 MW HVDC line. Table 4.3 presents the results of the market model simulations and the annualized investment costs for each scenario.

Table 4.3: Dutch case study - Results for the 2030 horizon

Case	Number of congested hours	Total energy above GTC limit	Total curtailed wind energy	Value of curtailed wind	Remaining congestion	Cost of investment
	hours	GWh	GWh (% of total wind energy)	M€	GWh	M€
Base ('3kA')	7492	13294	10955 (72%)	682	2338	0
A-2030 ('DLR')	5992	7890	7127 (47%)	445	763	0,2
B-2030 ('4kA')	5364	7015	6751 (45%)	418	264	12,3
C-2030 ('AC')	2071	1496	1496 (10%)	91	0	7,3[1]
D-2030 ('DC-1GW')	3104	2796	2794 (18%)	171	2	4,9[1] – 7,3[2]
E-2030 ('DC-2GW')	1045	565	565 (4%)	35	0	8,9[1] – 14,4[2]

Comparing the results presented in Table 3.2 and Table 4.3, it can be observed that the number of hours with congestions increase significantly. This is an obvious consequence of the higher RES generation levels considered in the 2030 horizon. As a consequence, the cost-benefit relation of expanding transmission capacity improves significantly in comparison to the 2020 scenarios with relative low congestion hours. From this it can be concluded that while technologies which allow a more efficient use of the transmission capacity (such as DLR) can be a cost-efficient solution to integrate RES generation in the short-term in the short-term, massive RES penetration will require further investments in network capacity and/or integration technologies.

4.3 Germany

In the 2030 horizon, four scenarios of grid-impacting technology development are compared for the German case study: (i) 2030A - base case; (ii) 2030B - one HVDC link of 2 GW; (iii) 2030C - use of FACTS and DLR (incl. 2 GW HVDC); (iv) 2030D - transmission capacity expansion for 12 lines (incl. 2 GW HVDC). Figure 4.1 shows the total annual differences in the generation dispatch in the different scenarios with respect to the base case (2030A).

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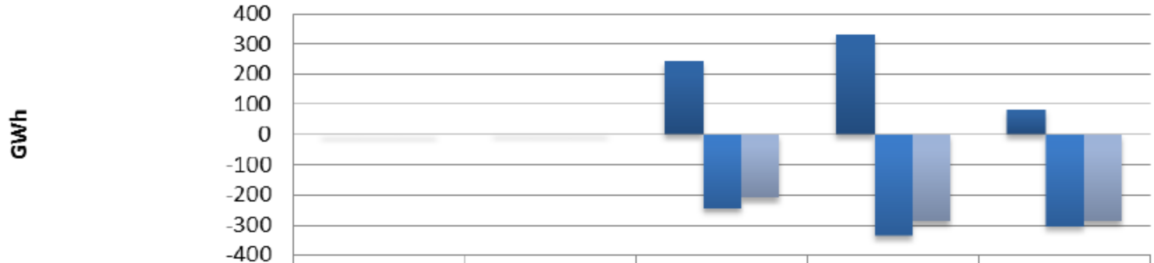

	∑ RES generation	hydro generation	turb generation	pump consumption	thermal generation
Difference B-A (GWh)	-4,5	-	242,8	328,2	81,2
Difference C-A (GWh)	-0,1	-	-248,0	-335,4	-306,4
Difference D-A (GWh)	-0,7	-	-212,9	-287,9	-289,5

Figure 4.1: German case study - Results for the 2030 horizon

The changes of thermal generation are visualized in Figure 4.2 as monetary fossil fuel savings and CO_2 emissions savings in M EUR/year in comparison to scenario (2030A). The highest reduction of CO_2 emissions is possible by implementing FACTS and DLR into the transmission grid, see scenario (2030C). The positive values are savings and negative values are expenditures.

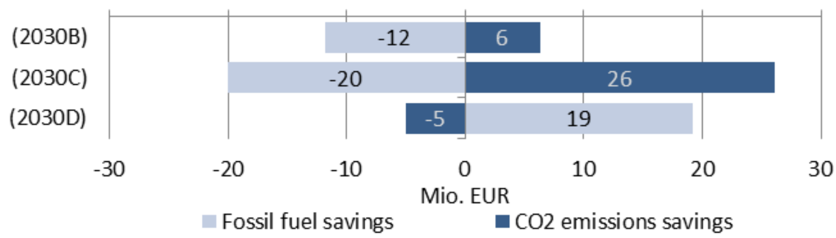

Figure 4.2: German case study - Fossil fuel and CO_2 emissions savings in M EUR in comparison to scenario (2030A).

4.4 Spain

In the Spanish case study, two RES integration solutions are separately assessed in the 2030 horizon: CAES storage and DSM through the implementation of load shifting programs. In this study, it is assumed that hourly load shifting does not modify total daily demand and the maximum load that can be shifted from one hour to the other is equal to 4 % of the original hourly demand. Figure 4.3 shows the total annual changes in the generation dispatch of Spain and France resulting from the implementation of load shifting in the former with respect to the base case scenario. It can be observed that DSM partially replaces the use of PHES units as it increases the flexibility of the system. This increased flexibility contributes to increase nuclear power generated not only in Spain but also in France. PHES consumption reduction in the DSM scenario corresponds to 13 % of total PHES consumption in the base case scenario. As a consequence of increased nuclear generation in France, net imports from France increases from 7,191 GWh in the base case scenario to 7,372 in the DSM scenario. It is worth mentioning that RES curtailment does not significantly change when DSM is implemented. The main reason for this is that in the base case scenario curtailment represents a low share of RES feed-in (0.1 %). According to the model results, the implementation of load shifting with a maximum of 4 % of hourly load shifted could reduce operation costs by approximately 182 M€/year.

The analyses performed for the 2030 time horizon showed that CAES has a similar impact on power system operation when compared to load shifting, although operation cost savings obtained in the analysis are much lower under the CAES scenario. The main differences resulting from both analyses can be explained by the lower efficiency of CAES storage, assumed to be equal to 65 %, in relation to demand shifting, which in this study could be compared to a type of storage with 100 % of efficiency, since it assumed that all daily energy moved upwards is equal to the energy moved downwards. This lower efficiency is translated into a net increase of total electricity demand, which in turn provokes an increase in thermal generation. As consequence, part of the cost savings obtained thanks to the higher integration of RES generation is compensated by higher thermal generation costs.

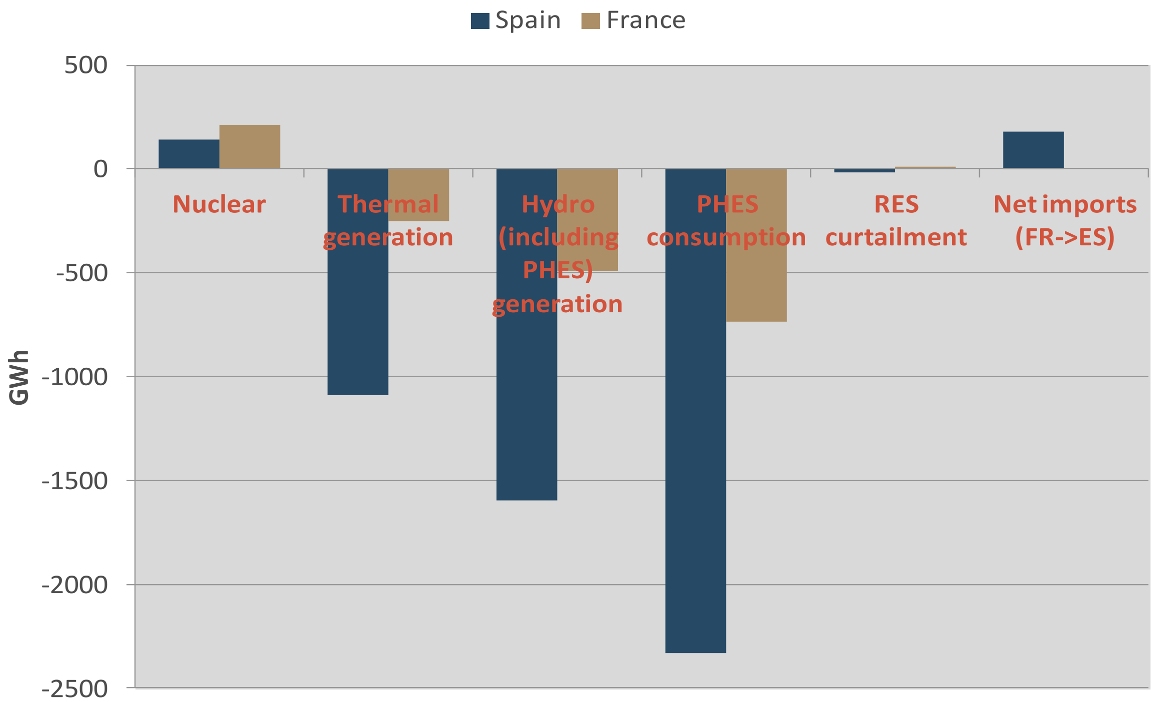

Figure 4.3: Spanish case study - Results for the 2030 horizon as differences between the DSM scenario and the base case

In practice, under a social welfare perspective, both technologies (i.e. DSM and CAES) should have a similar impact on power system operation. Nevertheless, the distribution of benefits among market participants will probably be not the same in the two cases. In the case of CAES, the agent who perceives more directly the benefits is the storage owner. Depending on the impact of CAES (or storage in general) in the electricity market, customers could be indirectly beneficiated by lower and/or flatter market prices. In the case of DSM, customers would be directly beneficiated. On the other hand, in case of small customers, the benefits obtained from DSM may be not high enough to incentive the final consumer to participate in the process. In this case, consumers will participate in DSM only if economic benefits compensate implementation costs (including the costs associated with the customers' comfort).

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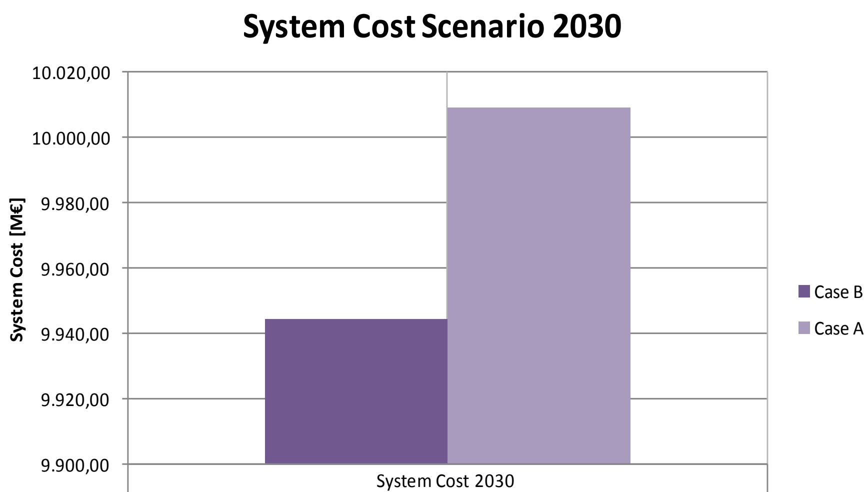
4.5 Italy

In the 2030 horizon, the Italian power system includes the main projects in accordance with the Ten Years National Transmission Development 2014 and the HVDC transmission link with North Africa. Huge amounts of RES production and of energy demand are expected. The benefits of new technological solutions (Case B) in terms of reduced internal grid constraints between market zones and higher integration of RES production in the Italian market have been evaluated and compared with the base case scenario, i.e. scenario without the technological solutions (case A). This analysis identifies the installation PSTs and HTLS conductors-OHLs as the best technical solutions.

The analyses performed for the 2030 time horizon showed that the average market price can be reduced by 0.1 €/MWh when PSTs and HTLS conductors-OHLs are implemented. Although market prices are slightly reduced, these technologies allow for a reduction in generation redispatch. This results annual cost savings for the Italian electricity system of about 65 M€/year.



	System Cost 2030
Case B	9.944,57
Case A	10.009,40

Figure 4.4: Italian case study - Results for the 2030 horizon

4.6 Austria

The Austrian case study for the 2030 horizon focuses on closing the 380 kV circuit in Austria. Five scenarios are compared in this time horizon: (i) 2030A (base case): without Carinthia 380 kV transmission line; (ii) 2030B: with 380 kV line; (iii) 2030C: without 380 kV line, but with FACTS; (iv) 2030D: without 380 kV line, but with DLR; (v) 2030E: without 380 kV line, but with FACTS and DLR. Figure 4.5 shows the total annual differences of power system operation in the different scenarios with respect to the base case (2030A).

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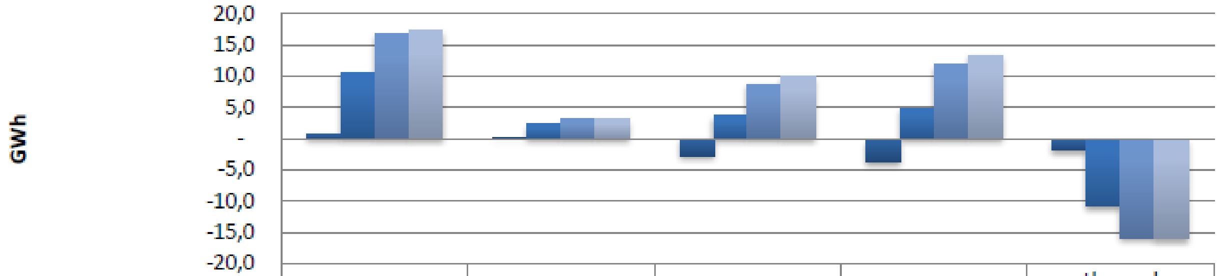

	∑ RES generation	hydro generation	turb generation	pump consumption	thermal generation
Difference B-A (GWh)	0,8	0,0	-2,7	-3,7	-1,8
Difference C-A (GWh)	10,6	2,3	3,6	4,9	-10,9
Difference D-A (GWh)	16,7	3,0	8,7	11,8	-15,9
Difference E-A (GWh)	17,2	3,0	9,9	13,3	-16,0

Figure 4.5: Austrian case study - Results for the 2030 horizon

Compared to the Base Case scenario (2030A) RES-E and hydro generation can be increased in all remaining scenarios. In addition, the PHS activities are increased except for scenario (2030B). Especially, the transition to a more flexible transmission grid via FACTS and DLR as in scenario (2030E) enables the highest changes. However, thermal generation can be reduced in scenarios (2030B-E); the maximal reduction in (2030E) is only 0.1 %.

4.7 Bulgaria

The 2030 analyses performed for the Bulgarian case study focuses on the use of flexibility solutions such as increasing storage capacity by installing PHES (148 MW) and batteries (introduction of 35,000 EVs) and implementing DSM (from 20 MW to 100 MW, depending on price signals). The impact of these solutions is separately and jointly assessed. Table 4.4 presents the results of the simulations for four different scenarios: (i) base case scenario without considering the studied technologies; (ii) base case + new PHES; (iii) base case + EVs; (iv) base case + DSM; (v) all technologies together.

Table 4.4: Bulgarian case study - Results for the 2030 horizon

TWh	I: Base case	II: PHES	III: EVs	IV: DSM	V: All	V-I
Nuclear	16,73	16,73	16,73	16,73	16,73	0,00
Thermal	15,00	14,38	15,04	14,97	14,25	-0,75
Conventional hydro (including PHES generation)	3,35	3,96	3,38	3,34	3,94	0,59
RES generation	7,16	8,14	7,24	7,21	8,29	0,57
Demand	40,50	40,50	40,50	40,50	40,50	0,00
PHES consumption	1,73	2,22	1,75	1,73	2,07	0,34
EV consumption	0,00	0,00	0,10	0,00	0,00	0,00
RES surplus	0,00	0,49	0,04	0,03	0,57	0,57
Thermal cost (M€)	984,88	948,39	987,34	983,44	940,69	-44,19

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Due to the fact the EVs increases the system demand, thermal costs increase. Regarding this, it is important to emphasize that this analysis does not take into account the positive impacts of the electrification of vehicles in the transportation sector, such as reduction of CO_2 emissions and dependency on fossil fuels. Furthermore, EVs contributes to a higher integration of RES production into power system operation, although this is limited by EVs' users' profiles.

Similar results were obtained for batteries, i.e. while they reduce the annual average system marginal cost by integrating higher levels of RES generation; they provoke a slight increase in thermal costs. This can be explained by the fact that batteries have efficiencies lower than 100 %, and, consequently, they increase total system's demand. Nevertheless, it is worth mentioning that batteries can reduce the needs for investments in distribution grids by flattening the load.

DSM also contributes to a higher integration of RES generation, reducing the average system's marginal price and thermal costs. The implementation of DSM is seen as beneficial since implementing demand response for industrial customers do not require large investments. For small customers, the required investments will depend on the DSM program implemented. For instance, peak shaving would require relatively low effects, while the implementation of load-shifting may require the automation of households and loads.

Finally, it was observed that the aggregation of several storage technologies provides better results than the sum of individual benefits. During the periods with RES curtailment, competition among alternative technologies exists based on the economic efficiency of each one, and, in some cases, jointly influence can be multiplied.

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5 2050 Analyses: selected results

5.1 Isle of Ireland

The longer time frame of 2050 allows multiple combinations of sensitivities, e.g. DSM, EV, RES+ (offshore wind, wave and deep water wind) and extra Sea Storage plants. Overall, twelve cases have been considered. Table 5.1 presents the summary of economic results for the following scenarios: (i) Base case 2050; (ii) sea storage connected to Great Britain plus extra sea storage plant connected to All Islands (LCHP_GB + OTH_AI); (iii) EV 40 %; (iv) EV 80 %; (v) DSM 40 %; (vi) DSM 80 %; (vii) DSM 80 % + EV 80 %.

It is worth noticing that a progressive reduction the Irish production of thermal power plants is obtained when implementing DSM and/or EV policies. The increased system flexibility brought by these technologies allows a higher integration of RES and reduces operation costs. DSM contributes to reduce grid development investments, although when combined with EVs investment needs increase. Connecting further storage to All Islands contributes to reduce grid investments and RES curtailment, although imports and production and costs increase.

Table 5.1: Irish case study – 2050 economic results

	Production [M€]	CO2 [M€]	Load shedding [M€]	Curtailments [M€]	Total Operation [M€]	Import(+)/Export(-) [M€]	Investments [M€]	Grand Total [M€]	NET Imp.(-)/Exp.(+) [TWh]
Basecase_S0_2050	104.1	50.1	0.0	98.4	252.6	338.3	247.8	838.7	-5.6
S0_2050_LCHP_GB+OTH_AI	188.2	90.5	0.0	18.8	297.5	396.8	114.5	808.8	-6.0
S0_2050_EV40	87.6	42.1	0.0	2.6	132.3	699.2	340.8	1172.3	-12.2
S0_2050_EV80	4.1	2.0	0.0	8.1	14.2	1008.0	356.3	1378.4	-15.4
S0_2050_DSM40	0.0	0.0	0.0	0.0	0.0	632.1	370.2	1002.3	-10.5
S0_2050_DSM80	0.0	0.0	0.0	0.0	0.0	571.0	263.4	834.4	-8.7
S0_2050_DSM80_EV80	0.0	0.0	0.0	0.0	0.0	1031.8	358.7	1390.6	-15.8

Figure 5.1 shows pumping and dispatchable generation, as well as wind curtailment. Thermal production is reduced as load flexibility is introduced in the system. When additional storage is installed, curtailment becomes negligible. Small storage plants are used when thermal units are producing due hourly prices' differences. When thermal units are not generating, the use of small storage plants is minimized (low hourly prices' differences do not compensate efficiency losses).

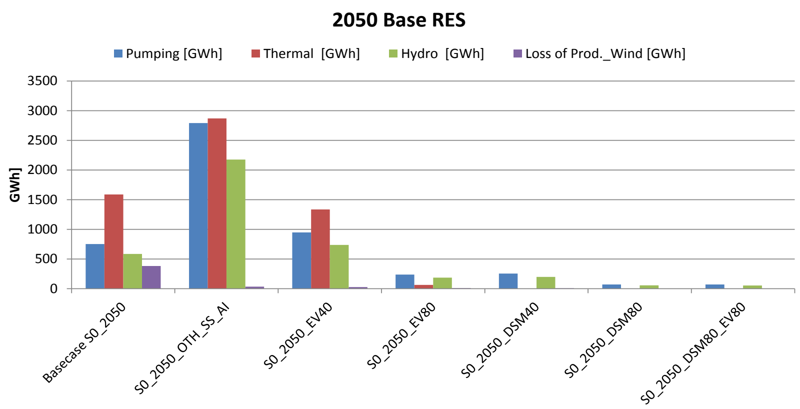

Figure 5.1: Irish case study – dispatchable generation, pumping hydro and wind curtailment.

Figure 5.2 presents EVs' consumption (Grid-To-Vehicle, G2V) and generation (Vehicle-to-Grid, V2G). As it can be observed, EV penetration acts as an extra load due to the use of

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energy for transport purposes and to efficiency losses in both V2G and G2V processes. The impact of EV penetration increase grid expansion needs in comparison to storage, DSM and the base case scenario. It is worth noticing that EV flexibility is used by the system. However, saturation occurs when also DSM is introduced. In this case a flexibility competition occurs and DSM replaces part of the EV flexibility due to its 100 % efficiency.

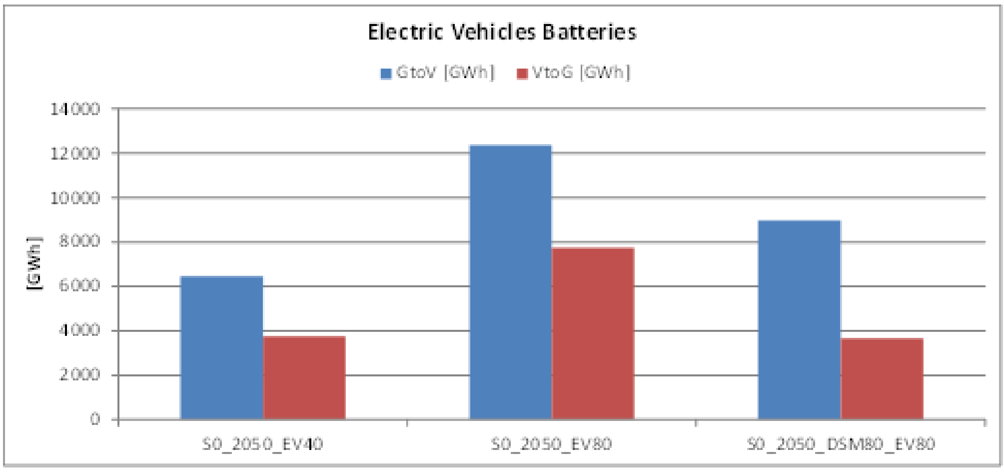

Figure 5.2 Irish case study – EV consumption (G2V) and generation (V2G)

Table 5.2 presents the economic results for the scenarios with additional RES generation (RES+), when Ireland becomes a net energy exporter with a fully decarbonised generation mix. DSM and SWS storage flexibility improve system performances, but the majority of advantages are related to export incomes.

Table 5.2: Irish case study – 2050 economic analysis, RES+ base.

	Production [M€]	CO2 [M€]	Load shedding [M€]	Curtailments [Meuro]	Total Operation [M€]	Import/Export [M€]	Investments [M€]	Grand Total [M€]	NET Imp.(-)/Exp.(+) [TWh]
RES+_2050_GB	0.0	0.0	0.0	148.6	148.6	-1345.5	573.5	-623.4	24.5
RES+_2050_AI	0.0	0.0	0.0	77.2	77.2	-1408.7	582.9	-748.7	25.6
RES+_2050_AI_DSM80	0.0	0.0	0.0	38.2	38.2	-1324.1	631.5	-654.5	24.1
RES+_2050_AI_EV80	0.0	0.0	0.0	55.6	55.6	-773.8	587.0	-131.3	14.1
RES+_2050_AI_DSM80_EV80	0.0	0.0	0.0	113.7	113.7	-1054.7	634.7	-306.3	19.2
RES+_2050_LCHP_AI+OTH_AI	0.0	0.0	0.0	65.5	65.5	-1398.9	594.4	-739.0	25.4
RES+_2050_MAI+OTH_AI_DSM80_EV80	0.0	0.0	0.0	30.2	30.2	-1240.8	656.7	-553.9	22.6

With reference to Figure 5.3, the system requires much more flexibility with additional RES generation: no competition appears when both EV and DSM are implemented at large scale.

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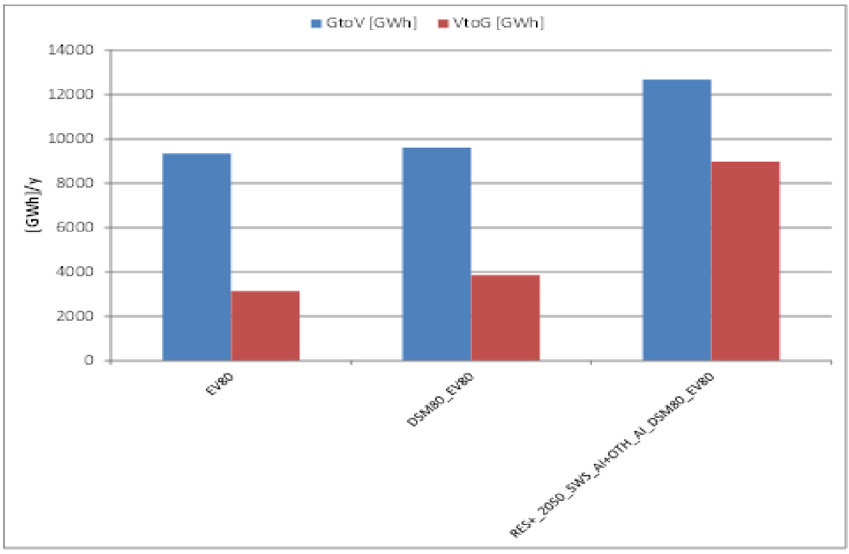

Figure 5.3: Irish case study - V2G and G2V EV mode.

Finally, different trajectories have been obtained by combining selected 2020-2030-2050 scenarios. These are trajectories are mainly based on the following:

- A base case trajectory where moderate RES and no flexibility is deployed;
- A DSM_EV trajectory related to penetration of DSM and EVs resulting from the implementation of demand-side policies;
- A RES+ trajectory together with the implementation of integrating technologies (Ireland becomes a net export of electricity.

Table 5.3 presents the Net Present Value of the different trajectories, in which conventional vehicle costs have also been included.

Table 5.3: Irish case study 2050 - Net present value of Development Trajectories.

	2050 total Costo1 [Meuro]	2050 Total Cost2 [Meuro]	2050 Electric Sector [Meuro]	TJ vs. Tjbase %
TJ5_DSM_EV_RES+_All_SWS_AI	40809	47201	19555	0.746362864
TJ5_DSM_EV_RES+_AI	41298	47690	19728	0.754091336
TJ4_RES+_AI	39684	48880	8646	0.772916859
TJ4_RES+_GB	39725	48921	8687	0.773569093
TJ4_RES+_All_SWS_AI	39747	48944	8709	0.773927136
TJ5_DSM_EV	45559	51950	23988	0.821460401
TJ3_EV+	46681	53072	25110	0.839200982
TJ3_EV	47895	55001	23912	0.869711687
TJ2_DSM+	47715	56911	16677	0.899907711
Tj2_DSM	49112	58309	18074	0.922005551
TJ1_BASE	54045	63241	23007	1

The Base case trajectory is the less efficient one. Strategies with implementation of RES+ have the best performances due to higher incomes resulting from the exports of excess of energy. Between these two extremes, it is worth noting that a combined DSM and EV deployment strategy, i.e. “Smart Grid initiative”, is able to provide up to 18 % savings. Finally, while a first SWS connected to Ireland brings economic benefits, additional SWSs may not provide significant additional benefits.

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5.2 Netherlands

A qualitative analysis is performed for 2050 horizon for the Dutch case study. Regarding electricity demand, although it is expect that electrical load grows due to the penetration of EVs and heat pumps this growth is expected to be compensated by increasing energy savings leading to modest load increments. On the other hand, the decarbonisation pathway pursued by the European Commission will imply in significant penetration of RES generation in the Netherlands. Figure 5.4 shows hours with energy excess in the Netherlands, based on the results of pan-European analyses performed in WP4.

In order to keep the system balanced, these generation surpluses need to be: (i) transferred to regions with RES deficits; stored locally or elsewhere; and/or curtailed. Transport is the preferred first option as (round trip) efficiencies of energy storages are rather low. As RES are distributed unevenly throughout Europe, this could lead to large power flows across Europe. Using the interconnected HVAC grid for this purpose will probably cause large unwanted transits (and losses) through third party countries. A HVDC grid could be an effective solution to accommodate these bulk power flows between generation and load centres. Nevertheless, transporting RES generation surpluses energy can be limited by the fact that RES have a high degree of simultaneity (especially photovoltaic). Therefore, complementing transmission expansion with storage solution could lead to a more efficient integration of RES. Finally, having some RES curtailment is efficient solution, since reducing RES surpluses to zero can lead to excessive investments costs.

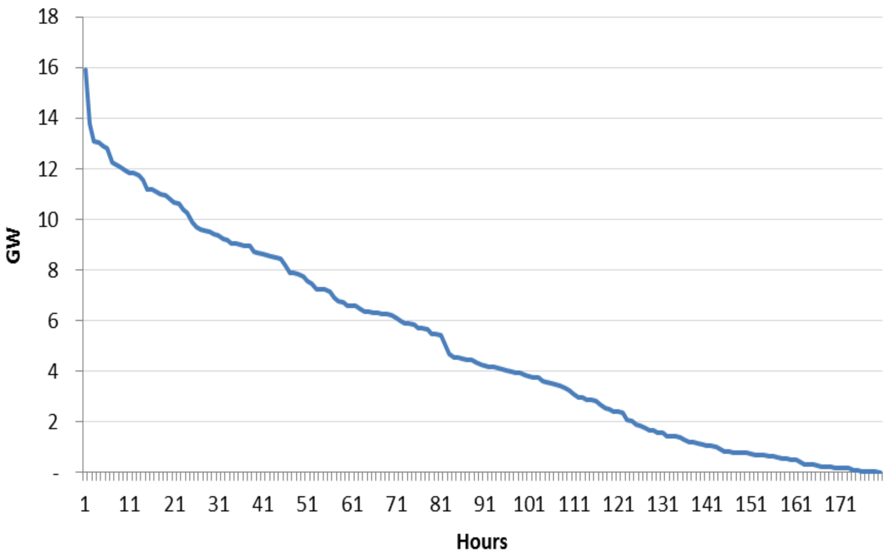

Figure 5.4: Dutch case study - Estimated RES generation surplus in the Netherlands by 2050 obtained from WP4 simulations

5.3 Germany

In the 2050 horizon, five scenarios of grid-impacting technology development are compared for the German case study: (i) 2050A - base case with three HVDC links of 6 GW; (ii) 2050B – use of FACTS (incl. 6 GW HVDC); (iii) 2050C – use of DLR (incl. 6 GW HVDC); (iv) 2050D - use of FACTS and DLR (incl. 6 GW HVDC); (iv) 2050E - transmission capacity expansion for 12

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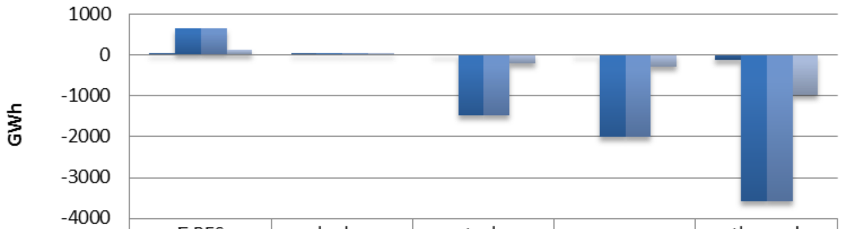
lines (incl. 6 GW HVDC). Figure 5.5 shows the differences in electricity generation for the scenarios of the time horizon 2050 in comparison to scenario (2050A), which is chosen as the reference case. In all scenarios on the one hand the RES-E generation is increased, on the other hand the thermal generation and PHES activities are reduced. The highest impact has the implementation of DLR. The reduction of thermal generation is for scenario (2050C) and (2050D) more than 50 %.



	∑ RES generation	hydro generation	turb generation	pump consumption	thermal generation
Difference B-A (GWh)	18,0	1,0	-21,9	-29,6	-138,8
Difference C-A (GWh)	631,7	41,1	-1.485,8	-2.008,9	-3.580,6
Difference D-A (GWh)	633,0	41,2	-1.495,4	-2.021,9	-3.592,7
Difference E-A (GWh)	118,6	7,0	-217,4	-293,9	-995,0

Figure 5.5: German case study - Differences in the generation structure for the time horizon 2050.

As mentioned before the highest savings can be achieved by the implementation of DLR, which leads to 60 % less CO_2 emissions. The associated monetary values of fossil fuel and CO_2 emissions savings are shown in Figure 5.6. Thus for scenario (2050D) savings of 318 M EUR are possible. These savings can be again invested into the transmission grid.

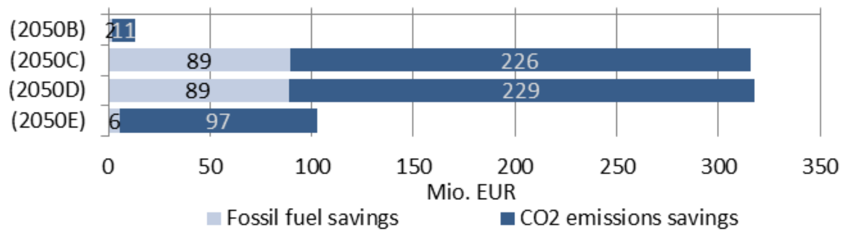


Figure 5.6: German case study - Annual fossil fuel and CO_2 emissions savings in M EUR for the time horizon 2050.

Figure 5.7 gives an overview of the annual electricity generation costs, normalized to case (2050A), for the different cases of the time horizon 2050. The highest reductions are possible for the cases (2050C) and (2050D), which is due to the reduction of thermal generation by around 50%.

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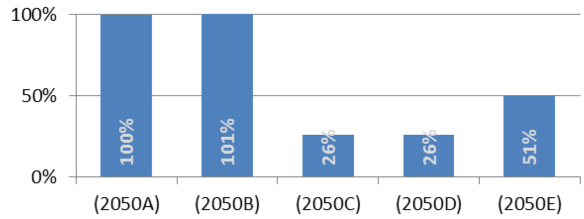

Figure 5.7: German case study - Overview of annual electricity generation costs of the different cases for 2050.

5.4 Spain

The 2050 horizon analysis for the Spanish case focuses on two types of innovative solutions to deploy massive amounts of RES generation in Europe: the first one focuses on a European-wide solution, i.e. the development of a HVDC supergrid; and the second one focuses on more localized (i.e. country level) solutions: batteries from EVs and DSM. Since the analysis focuses on the Spanish system, the interconnection with the North African system considered is the Spain-Morocco one. Therefore, apart from the Spanish system, the Moroccan power system is also modelled. In order to assess the impact of power flows coming from Africa in the operation of the Spanish system, other two important European demand centres are modelled: France and Germany. Unit commitment and generation dispatch is jointly optimized for the four countries, taking into account the conventional generation capacity mix, RES generation profiles, interconnection capacities, and demand in each one of them.

Load shifting is limited to a maximum of 8 % of the hourly load and the number of EVs considered is equal to 1,000,000. Regarding the supergrid scenario, Morocco-Spain (MO→ES) interconnection capacity is increased by 18 GW; Spain-France (ES→FR) interconnection by 8 GW; and France-Germany (FR→DE) interconnection by 7 GW in respect to the base case scenario. Figure 5.8 presents the total net power flows in the different interconnections resulting from the model simulations.

According to the obtained results, the increased system flexibility brought by the implementation of DSM and EVs in the Spanish system affects power flows especially in the ES→FR interconnection. This can be explained by the fact that this added flexibility allows not only a higher integration of RES generation produced in Spain, but also allows a more efficient use of nuclear power plants in France, contributing also to the integration of RES in the latter country. That explains the increase in net imports in Spain coming from France that can be observed in Figure 5.8. Regarding the HVDC scenario, it can be observed in the figure than an important share of RES generation coming from North Africa “stays” in the Spanish system: net flows in the interconnection MO→ES are increased by, approximately, 70 TWh; net flows in the ES→FR interconnection change direction, i.e. in the base case scenario Spain imports 20 TWh from France and in the supergrid scenario it exports 20 TWh to France. Therefore, in net terms, Spain transfers around 56 % of the additional energy imported from North Africa. France, in turn, increases net exports to Germany by 11 TWh, which represents 30 % of the additional energy in the French system (i.e. 40 TWh).

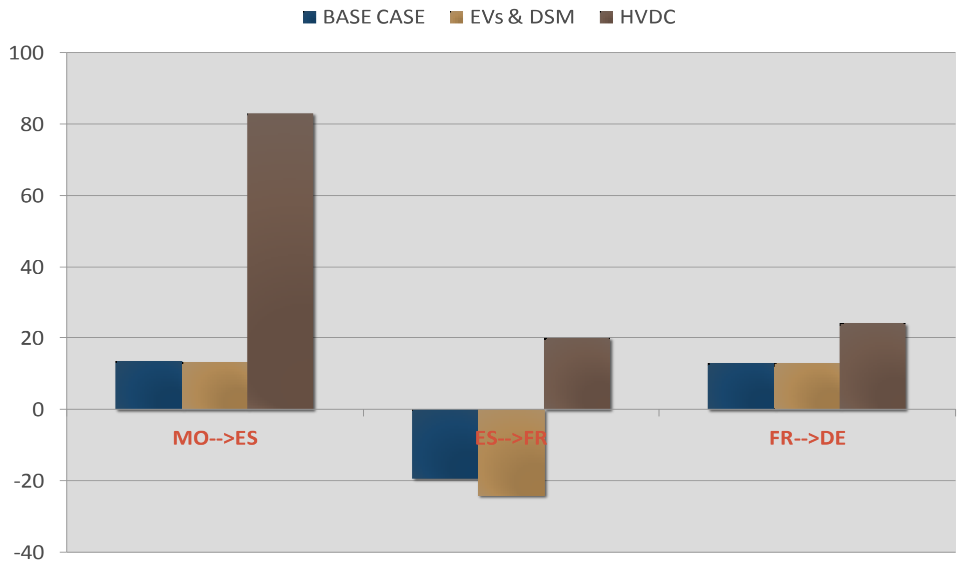

Figure 5.8: Spanish case study - Results for total 2050 net power flows in the different interconnections.

The obtained results showed that the additional RES generation coming from North Africa replaces mainly thermal and nuclear generation in the studied countries: in Spain, thermal and nuclear productions are reduced by 40 % and 14 %, respectively, when compared to the base case scenario; in France, thermal and nuclear power plants have their production reduced by 29 % and 7 %, respectively; finally Germany's thermal generation is reduced by 6 % in respect to the base case scenario. The reduction of thermal generation in those countries allows important thermal cost savings in the HVDC scenario. On the other hand, the development of a supergrid would require massive investment costs that would have to be distributed among all beneficiated systems.

5.5 Italy

In the 2050 horizon, the uncertainties related to grid developments and integration solutions are significantly higher. Therefore, nine scenarios have been analysed for the Italian case study. The 2050 base case scenario does not include new internal Italian electricity reinforcements from 2030 to 2050 except a new HVDC interconnection line with Albania; a huge increase of renewable production is expected though.

The nine scenarios are: (i) Base Case 2050; (ii) Planning AC; (iii) Planning AC + 8 GW PHES; (iv) Planning AC + DSM; (v) Planning AC + 8 GW PHES + DSM; (vi) Planning DC; (vii) Planning DC + 8 GW PHES; (viii) Planning DC + DSM; (ix) Planning DC + 8 GW PHES + DSM. Figure 5.9 shows the difference between system operation costs and investment costs related to the nine studied scenarios, respectively.

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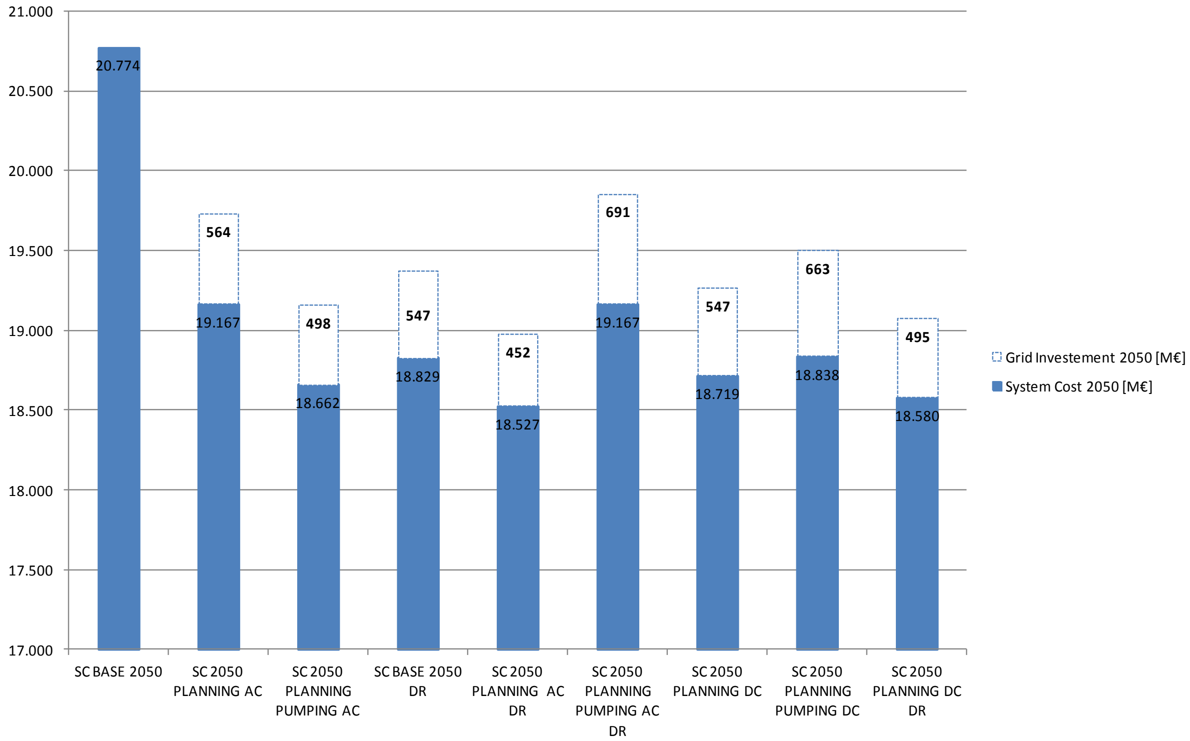

Figure 5.9: Italian case study - Results for total 2050 system cost and grid investement in the different scenarios.

Overall, the implementation of new technologies leads to benefits in terms of reduced market prices, increased inter-zonal import/export capacity, reduced congestions in the internal grid, and reduced CO_2 emissions. The highest cost savings are achieved in scenarios (v) and (ix): 2.250 M€/year and 2.200 M€/year, respectively.

5.6 Austria

For 2050 the Austrian case study focuses on further flexibility in the transmission grid. Nine scenarios are compared in this time horizon: (i) 2050A (base case); (ii) 2050B: use of FACTS; (iii) 2050C: use of DLR; (iv) 2050D: use of FACTS and DLR; (v) 2050E: high PHS; (vi) 2050F: high PHS and FACTS & DLR; (vii) 2050R: +33.3 % annual RoR production; (viii) 2050r: -33.3 % annual RoR production; (ix) 2050SK: with 2 GW HVDC line to Slovakia. For the first scenarios the differences in electricity generation are presented in Figure 5.10. Due to the transition to a flexible transmission grid RES-E generation and also generation of hydro power plants can be increased and otherwise electricity generation of thermal power plants can be reduced by approximately the same size. Additionally, the activities of PHS plants are diminished except for scenario (2050F), which includes not only higher installed capacity of PHS, but also FACTS and DLR. For the other scenarios the need for PHES is slightly reduced, which is a result of the more flexible transmission system.

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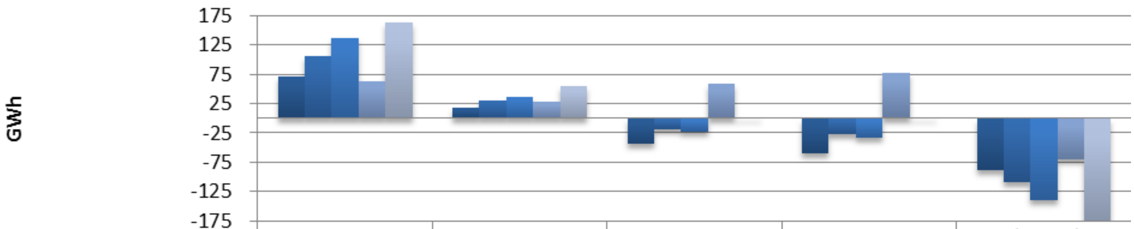

	∑ RES generation	hydro generation	turb generation	pump consumption	thermal generation
Difference B-A (GWh)	71	17	-44	-59	-89
Difference C-A (GWh)	105	31	-20	-26	-109
Difference D-A (GWh)	137	36	-24	-32	-141
Difference E-A (GWh)	64	29	58	78	-70
Difference F-A (GWh)	164	55	2	1	-178

Figure 5.10: Austrian case study - Differences in the generation structure for the scenarios (2050B) to (2050F) compared to (2050A).

Figure 5.11 shows the fossil fuel savings (in GWh) and the implicit CO_2 emissions savings (in kt CO_2). Additionally the monetary values are mentioned as well. The maximal savings can be achieved in scenario (2050F).

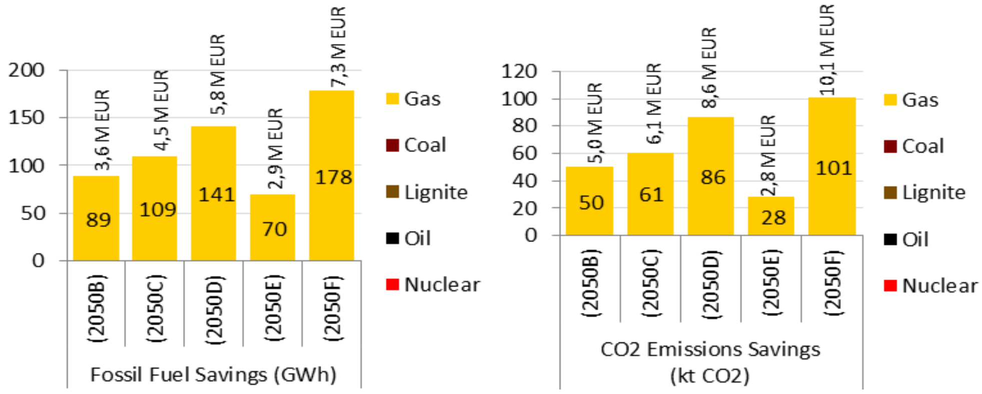

Figure 5.11: Austrian case study - Fossil fuel savings and CO_2 emissions savings in comparison to scenario (2050A).

Figure 5.12 gives a review of the annual electricity generation costs, normalized to case (2050A) for the different cases of the time horizon 2050. The highest reductions are possible for the cases (2050C), (2050D) and (2050F).

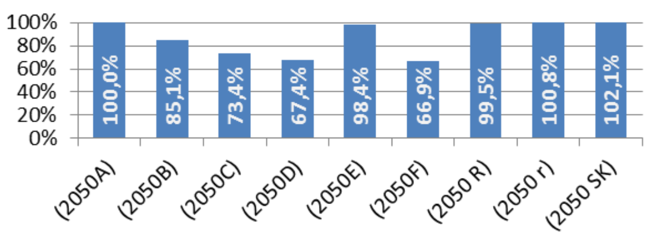

Figure 5.12: Austrian case study - Overview of annual electricity generation costs of the different cases for 2050.

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5.7 Bulgaria

The 2050 analyses performed for the Bulgarian case study focuses the same technologies assessed in the 2030 studies, although the potential for these technologies is increased in the 2050 horizon: 180,000 EVs); implementation of DSM (from 120 MW to 225 MW, depending on price signals) and 2 % storage/battery penetration level of the total demand connected to the distribution grid.

Table 5.4 presents the results of the model for the base case scenario (i.e. the scenario without the new technologies) and the scenario in which all assessed technologies are considered together. As shown in the table, the assessed technologies allows a reduction of 22.8 M€ in terms of thermal costs.

Table 5.4: Bulgarian case study - yearly system operation with and without the assessed technologies

TWh	With All New Technologies	Without All New Technologies	Difference
Nuclear	16.731	16.731	**0.000**
Thermal	10.152	10.003	**0.149**
Conventional hydro (including PHES)	3.590	3.643	**-0.054**
Batteries Generation	0.563	0.000	**0.563**
RES generation	7.622	7.073	**0.550**
Demand	35.520	35.520	**0.000**
PHES Consumption	1.902	1.930	**-0.028**
EVs Consumption	0.527	0.000	**0.527**
Batteries Consumption	0.710	0.000	**0.710**
RES additional utilization	0.550	0.000	**0.550**
Average marginal price (€/MWh)	75.50	75.03	**0.465**
Demand valued at marginal price (M€)	2 918.544	2 809.874	**108.670**
Thermal cost (M€)	1368.554	1345.803	**22.751**

It was observed that since RES generation increases from 2020 to 2050, the absolute amount of RES surplus is higher in the latter target year, although integration levels are higher in relative terms.

Large-scale penetration of EVs will be essential to achieve CO_2 emissions targets by 2050. In this sense, smart charging will be crucial to minimize their impact electricity prices. If smart charging is implemented, EVs can also contribute to the provision of ancillary service at the transmission and distribution levels.

The implementation of DSM is considered to be a cost-efficient solution for the integration of RES generation. Nevertheless, due to its relatively limited potentials (both for small and large customers), additional integration measures should be implemented, especially in the 2050 horizon when RES penetration is expected to reach significant levels.

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6 Main conclusions and policy recommendations

The analyses carried out within the GridTech project for the different case studies provide some policy insights for the different time horizons:

- In the short-term, FACTS and DLR devices are cost-efficient solutions to increase the use of the existing transmission capacity and, consequently, to avoid network congestions and RES curtailment. It is important to emphasize though that the increase of transmission capacity by applying DLR is highly correlated with the amounts of wind power. Therefore, when large amounts of power not generated by wind power plants (i.e. during periods with low wind speeds) have to be transported, DLR is less effective. Regardless, the importance of these type of technologies increase when permitting procedures are delayed and construction times of new transmission lines become quite long. Therefore, providing adequate incentives for TSOs to invest in this type of solutions is recommended. In this sense, regulators should recognize efficient costs incurred by system operators due to the investment in new grid technologies.
- In the mid-term, solutions like DSM, EV and storage technologies increase the system flexibility and contribute to the integration of larger amounts of RES production, reducing system operation costs. It was observed that the level of efficiency of these solutions can affect operation in a significant way. If efficiency levels of both options are similar, under a social welfare perspective, both types of technologies (i.e. DSM and storage) should have a similar impact on power system operation. Nevertheless, the distribution of benefits among market participants will probably be not the same in the two technology cases. In the case of EV and storage technologies, the agent who perceives more directly its benefits is the storage owner. Depending on the impact of EV and storage in the electricity market outcome, consumers could be indirectly benefitted by these technologies by facing lower and/or flatter market prices. In the case of DSM, consumers would be directly beneficiated by its use. However, the benefits obtained by small consumers from DSM may not be high enough to encourage them to participate in its deployment process. Normally, consumers will participate in DSM deployment only if the economic benefits they perceive are larger than the implementation costs they face, including the costs associated with the deterioration affecting the consumers comfort when they are enrolled in DSM programs.
- In the long-term, the development of a European overlay HVDC network can be a solution to achieve the European Commission's goal of reducing 80 to 95 % CO_2 emissions' by 2050. Some of the results pointed out that the development of a supergrid could bring significant economic benefits to European power systems' operation. Nevertheless, if a European supergrid is to be developed, a high-level of coordination between involved countries will be required. Furthermore, building this supergrid would require reaching an agreement on long-term RES production targets to be achieved in each system, the harmonization of network infrastructure planning processes, the development of common funding schemes, and a fair and efficient methodology to allocate investment costs among the involved countries. Therefore, policy makers must take into account all infrastructure and generation investments and transaction costs, as well as all potential benefits from these network and generation

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developments (not only those concerning operation cost savings) when deciding whether to go for a EU-wide solution (and possibly in cooperation with North Africa). Potential benefits from this supergrid can be larger than costs, but conclusions on the advisability of this solution should be robust to achieve the involvement of all relevant parties in this process.

Some policy further recommendations include:

- In some countries, such as Bulgaria, final electricity prices are defined by the regulatory commission, which, for political reasons, are kept below the level required in order to cover electricity's costs. This does not provide the required incentives for the TSO to invest in grid upgrade, expansion and in the application of innovative technologies. It is therefore recommended that electricity prices reflect electricity costs and be freely defined by the market;
- Regulatory authorities should recognize TSOs' investments in R&D projects when defining transmission charges;
- Very close cooperation among the TSO and DSOs is recommended (e.g. cooperation in what regards future perspectives of distributed generation and storage development). This includes mutual connected systems for operations and communications, common projects, clear policy for TSO and DSO obligations and control.
- Proper Demand Side Market rules have to be designed to keep demand volatility under control.

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