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European Renewable Energy Network

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European Renewable Energy Network

EUROPEAN PARLIAMENT

DIRECTORATE GENERAL FOR INTERNAL POLICIES

POLICY DEPARTMENT A: ECONOMIC AND SCIENTIFIC POLICY

INDUSTRY, RESEARCH AND ENERGY

European Renewable Energy Network

Study

Abstract

The targeted increase of renewable energy sources in the European energy mix to 20% by 2020, and the goal of an 80-95% CO_2 emissions reduction by 2050, will require changes to and extensions of the electricity grid. The integration of increasing shares of fluctuating renewable electricity, notably wind and solar power, into the grid is a long-term task that requires major investments, long-term planning at European level and endurance. It also requires a significant increase in the level of coordination of all relevant stakeholders in Europe. Important activities have started, but efforts need to be stepped up, and action accelerated.

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LIST OF ABBREVIATIONS

(A)CAES	(Adiabatic) Compressed Air Energy Storage
ACER	Agency for the Cooperation of Energy Regulators
BEV	Battery-Electric Vehicle
CCS	Carbon Capture and Storage
CEF	Connecting Europe Facility
CEPS	Centre for European Policy Studies
CH4	Methane
CSP	Concentrated Solar Power
DG	Directorate General
DR	Demand Response
DSM	Demand Side (Energy) Management,
DSO	Distribution System Operator
EC	European Commission
EDSO	European Distribution system operators for Smart Grids
EEGI	European Industrial Initiative on the Electricity Grid
EHV	Extra High Voltage
EIB	European Investment Bank
ENTSO-E	European Network of Transmission system operators for Electricity
EP	European Parliament
ERCOT	Electricity Reliability Council of Texas
ERGEG	European Regulators' Group for Electricity and Gas
ETS	Emissions Trading System

FACTS	Flexible AC Transmission Systems
FCEV	Fuel Cell Electric Vehicle
FLPG	First Loss Portfolio Guarantee
GHG	Greenhouse Gas(es)
GW	Gigawatt
H2	Hydrogen
HV	High Voltage
HVDC	High-Voltage Direct Current
IEA	International Energy Agency
IEM	Integration of Electricity Markets
ITRE	Committee on Industry, Research and Energy
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LGTT	Loan Guarantee for TEN-T Projects
MoDPEHS	Modular Development of a pan-European Electricity Highway System
MW	Megawatt
NC	Network Code
NGO	Non-Governmental Organisation
NREAP	National Renewable Energy Action Plan
NTC	Net Transfer Capacity
PBI	Project Bond Initiative
PCI	Project of Common Interest
PHEV	Plug-in Hybrid Electric Vehicles

PV	Photovoltaics
R&D	Research and Development
RD&D	Research, Development and Deployment
RD&I	Research, Development and Innovation
RED	Renewable Energy Directive
RES	Renewable Energy Sources
RES-E	Electricity from Renewable Energy Sources
RSFF	Risk Sharing Financial Facility
SAC	Special Area of Conservation
SMES	Superconducting Magnetic Energy Storage
SoS	Security of Supply
SOT	Solar Thermal Power
TIF	European Transmission Infrastructure Fund
toe	Tons of Oil Equivalent
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
V2G	Vehicle-to-Grid
VRE	Variable Renewable Energy

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EXECUTIVE SUMMARY

Background

An important goal of EU energy policy is to increase the share of renewable energies. The Renewable Energy Directive[1] sets a target of a 20% share of renewable energy to be achieved by 2020. Renewable energy development will also play a major role in achieving the long-term objective of 80-95% CO_2 emissions reduction by 2050 as set by the European Council. The recent assessment by the European Commission shows that the 20% target is likely to be achieved and even surpassed by 2020[2].

Increasing shares of renewable power, notably fluctuating wind and solar power, require changes to and extensions of the electricity grid. The extent of the modifications depends on a number of factors and develops over time with increasing renewable shares. Other options to allow for higher shares of fluctuating renewable power in the grid are supply-side management, i.e. reducing renewable power production at certain times by active plant management; demand-side management/demand response, i.e. incentivising consumers to increase consumption during periods of high production and to decrease it during periods of low production; and electricity storage, which is very small today in comparison to the amount of renewable generation to be integrated.

Aim

The objective of the present study is to identify the energy network infrastructures needed to cope with the increasing share of renewable energies. The analysis covers a timeframe up to 2050 taking into account different existing projections of renewable energy development. Published infrastructure development priorities as well as methodologies including notably infrastructure cost benefit analyses are critically assessed.

The study furthermore analyses the relationship between the promotion of renewable energy generation and related infrastructure on the one hand, and other (energy) policy goals and existing legislation at EU level on the other. Obstacles to grid-roll out are identified and policy recommendations are proposed.

Headline results

The integration of increasing shares of fluctuating renewable electricity into the grid is a long-term task that requires major investments, long-term planning at European level and endurance.

Renewable electricity generation scenarios

All published long-term electricity **supply scenarios for Europe** respect the greenhouse gas reduction goal of 80-95% (or even 100% renewable electricity) by 2050. However, these scenarios differ in terms of CO_2 reduction over the next decades and final energy demand by 2050.

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[1] Directive 2009/28/EC Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

[2] European Commission Communication "Renewable Energy: Progressing towards the 2020 target", 31 January 2011.

Whilst the short-term renewables portfolio developments are rather coherent throughout the different scenarios until 2020, the mid to long-term portfolios of deployed renewable energy technology options increasingly differ in the scenarios, with regard to the total renewable electricity generation (mostly in the range of 3,500 to 5,000 TWh in 2050) and even more so with regard to the share of the different renewable energy sources (RES).

Concerning the **geographical distribution** in Europe, renewable electricity production is generally less centralised than fossil power plants, with the exception of large wind parks, especially in the case of offshore wind. Consequently, renewable power is fed into the electricity grid at all voltage levels: rooftop PV, bio-methane combined heat and power, free-space PV, small hydro power, onshore wind (parks), large hydro power, offshore wind parks (in ascending order of voltage levels).

There is sufficient technical **potential**[3] for renewable electricity production within the EU27 borders to even exceed current electricity demands. Geographical potentials for onshore wind and building PV are generally available all over Europe, with a concentration of onshore wind potentials along coastal areas; and in the case of PV in Central and Southern Europe. Hotspots of offshore wind potentials are in Northern Europe (North Sea, Irish Sea, Baltic Sea), while solar potentials are highest in Southern Europe (PV, solar thermal power).

By the end of this decade, wind power is expected to be **cost-effective** in the European power markets, provided that preferential grid access is granted. Through further mass production and technological development, solar PV is expected to achieve grid parity around 2015 in Central and Southern Europe, i.e. lower production costs than consumer electricity prices including taxes and grid tariffs. Support policies of renewable energy will, however, still be required after simple grid parity is achieved, as balancing fluctuations will still need to be ensured by the grid.

Exchange of renewable electricity among EU Member States and possibly with other EU neighbouring countries mutually increases the **security of energy supply** because of better protection against intermittence and enhanced diversification of the supply bases. This will benefit the European market integration, and may stimulate further European integration as a whole.

Infrastructure development needs

Transmission grid expansion is a powerful option to facilitate integration of electricity supply from renewable sources. Essentially it allows transporting electricity from locations of renewable production to consumption centres. More specifically, it helps to smooth out variability in renewable generation, by permitting balancing supply and demand of electricity within the network system at all times. This characteristic is fundamental for renewables integration, which are often located in isolated areas far from the main centres of consumption. Better grid interconnections also allow improving reaction times with regards to power demand, which implies an overall better management of the power system.

[3] The technical potential for RES generation takes into account all technical, structural, ecologic and legal restrictions to the theoretical potential of e.g. solar irradiation on a given surface area. Economic criteria, however, are not applied, which are subject to the changing economic environment and policy intervention. The technical potential can increase over time with the advances of technology.

Grid expansion is not the only option when dealing with RES integration issues, particularly given certain difficulties encountered (see section "Obstacles to infrastructure development" below). Research efforts analysing and **optimising portfolios** of the different options for grid integration of RES detailed below need to be stepped up in order to find cost-optimal allocations of investments.

The most important non-exclusive options are considered below, among which the improvement and upgrade of the existing grid obviously plays an important role.

Grid operations can be improved through thermal monitoring of overhead electricity lines, which increases the transmission capacity of existing lines.

Generation (supply side) management includes more flexible conventional thermal power plants, dispatchable renewable power sources (such as turbines or gen-sets running on bio-methane) and even curtailment if electricity supply exceeds demand.

Flexible demand, e.g. dispatchable charging of e-mobility and other electricity loads, notably of large electricity consumers, also facilitates the integration of renewable electricity. **Demand response** of small "smart" energy using products, in high numbers, in private hands has to be carefully assessed regarding cost-benefit, system vulnerability/criticality and data privacy. The EU is the appropriate regulatory level for a coherent approach throughout Europe. The control of **battery-electric vehicle** (BEV) charging can be seen as "smart" demand response that deserves a special mention. Regulatory frameworks would be required in this case to ensure that BEVs are connected to the grid whenever possible, communication protocols are interoperable and participation in the electricity market provides sufficient remuneration. Feeding back the power stored in BEV batteries is also discussed (Vehicle-to-Grid – V2G), but the challenges are likely to prevail over the benefits. However, retired vehicle batteries may possibly be used as stationary batteries in the distribution grid (2nd life).

Electricity storage including pumped hydro storage, batteries, hydrogen, compressed air storage, etc. reduces grid extension needs and increases local energy supply security. There is a broad set of electricity storage options available at different development stages. No single electricity storage option can cover all storage requirements in all European regions alike, i.e. from small to large scale as well as for short, medium and long-term storage needs. Energy storage can be situated near centres of renewable supply as well as in the distribution grids. Similarly to the existence of **strategic reserves** of oil and gas in the European Union, future policy initiatives for EU transmission grid development should consider, allow or even demand for the installation of large scale and long-term energy storage capacities from renewable sources.

Change of **market design** and procurement of system services for more economic accommodation, e.g. shorter gate closure times, dynamic reserve allocation, ancillary services also from variable generation, allows among others to tap more precise short-term renewable generation output predictions and to reduce the amount of reserves to be provided by conventional generation.

Finally, electricity can be **converted into fuel** for heating or transport use. Power-to-gas production – either as hydrogen (H_2) or synthetic natural gas (SNG) – allows for grid balancing during fuel production, storage of electricity as a fuel for use in the transport sector, as well as re-electrification.

To this end, regulations for the uptake of hydrogen **fuel cell-electric vehicles** (FCEVs), such as giving fuel cell-electric vehicles a factor similar to battery-electric vehicles in the EU Renewable Energy Directive[4] or supporting hydrogen infrastructure in the context of TEN-T[5] projects, could facilitate the overall integration of renewable electricity in the grid.

The plans for **cross-border interconnections** up to 2020 are presented in the ENTSO-E Ten Year Network Development Plan 2010. They are listed according to a bottom-up approach, whereas prioritisation should be based on a top-down approach which would reveal the relative merits of different projects. This work is ongoing and it should be supported by research.

Interconnection priorities are dependent upon the distribution of European RES potentials, which are unevenly distributed across Europe. In turn, this creates the need for long-distance power flows across EU Member States.

In the short term, countries such as Germany, Ireland and Spain, have already acknowledged the actual need for further grid expansion in a number of reports. In the policy scenarios up to 2020 the focus is on strengthening the interconnections between the Scandinavian reservoirs and Central Europe, while also increasing the trading capacity between Spain/Portugal and France.

The **research performed so far is not conclusive** on whether these prioritisations are optimal. Given the fact that infrastructure investments are long-term and have a high cost, well-organised research efforts and robust methods should be devoted to properly identifying the infrastructure investment priorities.

Priorities beyond 2020 should include a longer-term view, as the needs of post 2020 should affect what is planned and built before then. This will be even more demanding for the research methods and approaches applied, as the uncertainty concerning future generation and demand scenarios increases. Studies done so far serve to build the required understanding, but a lot more effort is required and would be worthwhile.

Infrastructure investments associated with the integration of renewable generation may bring about substantial **benefits beyond the expected increase in the level of RES energy** that the system can safely absorb; it is necessary though to be able to compute the actual costs and benefits of such investments. Extra benefits of transmission are mainly related to the increase in the level of integration achieved among EU power systems, which will yield greater **economic efficiency as well as security of supply**. The benefits of storage capacity, demand response and supply-side management are, however, expected to be predominantly of a local nature.

Until full cost competitiveness is achieved, different **charges and regulations** for grid connections will have an impact on where and what type of variable power generation will be built throughout Europe. This can have large economic consequences from the power system perspective. Large increases of solar PV, for example, can overburden **distribution grids**, which may require upgrades and extensions also on these voltage levels, while distributed generation and storage can, on the other hand also relieve transmission grid utilisation, thus reducing the need for extensions and increasing regional energy security. Resource use planning and transmission planning should be combined for the best result.

4 Renewable electricity consumed in battery-electric vehicles is multiplied by a factor of 2.5 for the calculation of the RES share in transport fuels because of the higher vehicle efficiency compared to internal combustion engines. In this logic, hydrogen should be given a similar factor based on the high efficiency of fuel cells.

5 Trans-European Transport Network.

Connection charges should be harmonized at the European level in order to avoid market distortions and large differences between Member States.

As a consequence, comprehensive **cost-benefit analyses** of possible infrastructure investments are important for determining which infrastructures to build and for being able to properly allocate their costs to system stakeholders, which may be critical for getting the construction approvals. Nevertheless construction and operating costs of network facilities are often difficult to assess. Investments in different types of renewables-associated infrastructure may exhibit a high level of substitutability between different options. Hence, benefits and costs of the different possible infrastructure investments should be compared to determine which one to carry out.

Some of the benefits of infrastructure cannot be expressed in economic terms, such as enhanced competition between producers, security of supply and improvement of environmental condition due to a larger amount of RES. Others can, but are highly sensitive to assumptions made on the operation conditions in the system. Generally, there is a **lack of reliable data** on infrastructure costs and benefits. In order to appropriately carry out cost-benefit analyses, the high level of uncertainty about the future evolution of the system should be taken into account.

In order to advance the construction of new infrastructure, a number of stakeholders and institutional actors must be engaged. The role of network operators and energy regulators, will be fundamental in promoting the policies needed. Given the issues at stake, consumers and information and communication technology companies, are also expected to play a more important role in the future.

Currently, the **main investors** in energy infrastructure projects are international financial institutions, such as the European Investment Bank; increasingly, private investors will be expected to contribute to the financing of energy infrastructure projects.

The **European institutions** will play multiple roles:

- Setting clear and long-term goals;
- Providing criteria for the selection of projects;
- Monitoring and coordinating European projects to avoid overlapping.

Interplay with other energy policy goals and legislation

The interactions between renewable energy integration policy and related infrastructure deployment with main EU energy policies present potential benefits and conflicts. The three focal aspects of energy policies are EU market integration and liberalisation, security of supply and environmental policy.

The deployment of grid infrastructure projects presents **potential synergies** in relation to both the integration of RES into the network system and internal market goals:

- In order to integrate more variable RES electricity at the European level, it will be necessary to strengthen the electricity system and increase interconnections. These actions combined will reduce congestion episodes and allow for more electricity to be traded on the market. Future incentives affecting the investment and utilisation of interconnectors are of particular importance.
- Offshore wind integration and the development of Network Codes can also serve internal market goals in relation to infrastructure deployment and trading.

There are also **potential conflicts** between internal market policies and RES integration:

- National incentives can create cross-border obstacles to RES deployment;

- The increasing amount of RES in the system reduces available transmission capacity for TSOs' commercial purposes and increases the need to use the system security margin to ensure network stability;
- An important conflict lies in the current method used in the electricity balancing market; in fact, in order to further improve RES integration, there will need to be a change towards a system in which balancing resources will be shared;
- With higher renewables penetration there is a greater need for backup capacity, which implies that fossil fuel thermal capacity will still be required in the transition phase to a low carbon economy.

Notwithstanding the delay in the application of the **Third Energy Package**, various actions have been taken in order to improve the interplay of the various actors in the energy field. Doubts concerning the ability of ENTSO-E to well serve consumers' interests can be reduced thanks to the intervention of ACER as a "monitoring agent", in particular with respect to the TYNDP and ENTSO-E's objective to develop an electricity system-wide cost-benefit analysis methodology. Capacity mechanisms practice should be encouraged at the European level.

Integration of RES energy can benefit **security of supply** in various ways:

- RES reduce the dependence on fossil fuels;
- There is virtually no risk of resource scarcity;
- RES integration will help to reduce energy price volatility and improve energy conditions for poorer or remote areas.

The **variability of renewable energy sources** does, however, imply certain risks with respect to security of supply: wind, solar, wave and tidal energy require additional efforts for the system to remain stable and secure at a high level of penetration, albeit those issues are not technically insurmountable. Among the options proposed to contain variability issues, are improved forecast tools, especially for wind, integration of different balancing areas (national and European level) and increasing back up and Demand Side Management (DSM) capacity. The application of such schemes might be easier since costs for most mature technologies are expected to decrease in the near future.

Environmental legislation plays an important role with respect to renewable energy policies. While the cost of implementing **climate change** policies is expected to decrease over time, the relation between RES policies and carbon prices in a scheme such as the Emissions Trading System (ETS) is complicated. The system in place arguably fails to send strong enough price signals to polluters.

The merit order effect as the basis of the price building mechanism at the power exchanges leads to a situation in which both the CO_2 reduction policy and RES support generate **distributional effects**. A carbon price should be added to the electricity price and utilities' profits, whereas renewable generation is expected to have the opposite effect. This results in a situation in which policies with strong carbon price signals, notably through the ETS, might not significantly incentivise an increase in the share of RES.

The potential risks of renewable energy deployment for the **natural environment** are an important factor in EU energy policies. The impacts of renewable energy infrastructure on nature are at present rather limited, mostly due to the still low penetration of renewables. With increasing market penetration, the potential risks of renewable energy deployment on the natural environment will play an increasing role in EU energy policy.

As soon as good sites with high renewables potentials and low risks for nature and wildlife become scarce, early spatial planning and site selection with broad stakeholder participation will be key to avoid conflicts. The Natura 2000 Network sets a solid framework for the reconciliation of economic activities with environmental objectives. Appropriate deployment of this framework is essential.

Obstacles to infrastructure development

In most circumstances, **technical obstacles** to the extension of the electricity grid are not perceived as insurmountable by stakeholders. On the one hand, stakeholders have acquired experience on a case-by-case basis, while on the other hand "knowledge-sharing" among European countries has helped to overcome technical barriers. One of the main issues is the variability of renewable energy production, which makes the accurate prediction of renewable production necessary for network management difficult. Photovoltaics (PV) integration can also lead to problems, particularly at the distribution level.

The **economic obstacles** are more pressing, particularly in relation to the application of the Third Energy Package and electricity market integration. The European electricity market is still dominated by a small number of large producers, heritage of a collection of natural monopolies, where competition is hindered by disincentives to further invest into interconnections. In the same way, cross-border disputes on infrastructure projects arise from the incapacity of stakeholders to appropriately allocate the costs and benefits of a specific project. Equally important is the fact that some distribution system operators (DSO) are de facto unable to cover the cost of new investments because of tariff measures, which discourage them to invest into smart energy technology.

Lack of public acceptance is considered by many as one of the most important obstacles to the deployment of energy infrastructures, in particular grid roll-out. There are several issues at the heart of public opinion, which vary in importance depending on the project location, extension and proximity to populated areas. Environmental issues certainly have a strong influence on the opposition of local population and NGOs. Concerns related to the effect of new infrastructure projects on bird life, water resources and land also have a considerable impact in the permitting procedures phase through the Environmental Impact Assessment (EIA), which according to the involved stakeholders leads to heavy administrative burden and delays. Public discontent also derives from fear of health risks related to the exposure to low frequency electromagnetic fields and the negative visual impacts on the landscape, which also affects landowners' property value.

Amid the **administrative obstacles**, various issues have been analysed, starting with the uneasiness of transmission system operators (TSO) in dealing with a heterogeneous European regulatory framework and lengthy and difficult permitting procedures at the national level. The need for more harmonisation at the European level is also felt with respect to Network Codes, particularly for high voltage connection of wind energy. Lastly, changes will have to take place in the current procedural system of granting grid access to Distributed Generation (DG) producers, since the current system of connection charges and permitting procedures discourages the intake of new projects.

The European Commission has recently proposed a **European Infrastructure Package** (EIP) which plans to tackle some of the obstacles identified. It includes the proposal of a regulation on "Guidelines for trans-European energy infrastructure", which promotes the application of a certain number of important measures. Notably, one focus is the promotion of the internal energy market. The proposal also suggests the creation of a "Regional Group" for each priority corridor. The main stakeholders should be part of these groups in order to promote dialogue among different parties throughout the project selection phase.

The proposal also advocates the creation of a single-entity organ dealing with all administrative procedures at the national level, in order to reduce the length of permitting procedures. With respect to public acceptance, along with normal planning, stakeholders will need to prepare plans for a public consultation no later than two months after the approval motion. The proposal also puts forward the application of a system of cost-benefit analyses, to be governed by TSOs and energy regulators, in order to overcome stagnation in case of cross-border issues. Energy regulators will also be required to promote incentives to invest into new energy infrastructure. The actual outcome of the proposal will ultimately depend on the Member States' resolution to apply these rules, and on the political support to the proposal, both at the European and the national levels.

Policy recommendations

Detailed policy recommendations are summarised in the concluding chapter of the present study.

In all of the following areas there are significant issues to be considered both jointly and independently:

- Crosscutting issues
- Infrastructure priorities
- Harmonisation of markets
- Nature protection
- Technology development
- Electric mobility

Optimising the European electricity grid on the basis of a thorough system-wide socio-economic analysis of costs and benefits is crucial to cost-effectively integrate RES into the network. Given the current lack of scientific analysis of this kind, it is ambitious to expect ENTSO-E to submit its methodology for an energy system-wide analysis only one month after the proposed Regulation on guidelines for trans-European energy infrastructure[6] would enter into force. It also requires significant action to coordinate all the relevant stakeholders in Europe, including policy, grid operators, research and civil society. Relevant activities have started, but efforts need to be stepped up, and action accelerated, in order to optimize grid development and thus to avoid the grid being the limiting factor for the targeted growth of renewable energy deployment in Europe.

6 COM(2011)658.

1. Renewables generation development scenarios

KEY FINDINGS

- **Long term electricity supply scenarios for Europe** all respect the greenhouse gas reduction goal of 80-95% (or even 100% renewable electricity) by 2050. Scenarios differ in terms of CO_2 reduction over the next decades and final energy demand by 2050. While short term development of the renewable electricity portfolio is quite coherent throughout the different scenarios until 2020, the mid to long term portfolio of deployed renewable energy technology options increasingly diverts between the scenarios.
- Renewable electricity production is generally **less centralised** than fossil power plants, with the exception of large wind parks, especially in the case of offshore wind. Consequently, renewable power is fed into the electricity grid at all voltage levels: building PV, bio-methane combined heat and power, free-space PV, small hydro power, onshore wind (parks), large hydro power, offshore wind parks (in ascending order of voltage levels).
- There is **sufficient technical potential for renewable electricity production** within EU27 borders to even exceed current electricity demands. Potentials for onshore wind and building PV are generally available all over Europe, with a concentration of onshore wind potentials along the coastal and mountainous areas; and in the case of PV in Central and Southern Europe. Hotspots of offshore wind potentials are in Northern Europe (North Sea, Irish Sea, Baltic Sea), while solar potentials are highest in Southern Europe (PV, solar thermal power).
- By the end of this decade, all **renewable power sources will be cost-effective** in most power markets in Europe, provided that preferential feed into the grid is granted. Deployment of renewable power plants will then be less dependent on financial support policies. Exchange of renewable electricity among EU Member States as well as with EU neighbouring countries mutually increases the energy supply security and fosters both pan-European and inter-European integration.

1.1. Development of renewable energy generation

Infrastructure requirements are very dependent on the amount and portfolio of new generation capacities that need to be connected to the grid. Therefore, this chapter reviews different scenarios proposed by diverse groups including academia, the European Commission, business associations, non-governmental organisations and management consultancies.

Only scenarios that are sufficiently comprehensive in scope and detail are considered here, i.e. data for European countries are available at least for one of the years 2020, 2030 and 2050, and data are differentiated by RES technology. A number of other scenarios have been published in recent years, which are not included in the present analysis for lack of detail in results presented. This report does not include modelling of new scenarios but uses the **existing projections** to give an idea of the situation to be faced in the time horizon considered, i.e. with a view to 2020, 2030 and 2050. To this purpose, two representative scenarios have been selected (see section 1.1.3): a baseline scenario (sort of business as usual) and a high renewables one (where techno-economic developments and socio-political support favour the integration of renewable generation).

However, projections into the future face many **uncertainties** and thus, even when taking into consideration diverse scenarios and sources, real developments will probably differ considerably from the suggested scenarios, especially for 2050. For 2020, more viable and concrete predictions can be and have been made.

Most scenarios were developed before the Fukushima disaster, thus conventional plant extension might be overrated as some countries have since changed their policies regarding nuclear power.

1.1.1. Renewable energy scenarios

Table 1 shows an overview of different scenarios. It is important to notice that the ENTSO-E best estimate includes a number of non-EU countries[7]. However, this scenario will still be used in the following analysis. The ENTSO-E Best Estimate Scenario only includes existing generation units and those whose commissioning is highly likely, and thus the resulting values for 2020, especially for renewables projects with shorter planning times, are relatively low. Furthermore, the inclusion of non-EU countries does not significantly influence the projection outcomes.

[7] This includes Bosnia-Herzegovina, Switzerland, Croatia, Iceland, Montenegro, Former Yugoslavian Republic of Macedonia, Norway, Republic of Serbia, Ukraine-West.

Table 1: Overview of scenarios analysed

Scenario	Scenario variant	Editor, Publication year	Scenario type	Time steps	Geographical coverage
Scenario Outlook and System Adequacy Forecast (SO&AF)	**Best Estimate**	ENTSO-E, 2011	Aggregated network operator projections	2025	EU 27, BA, IS, MK, ME, NO, RS, CH
National Renewable Energy Action Plans (NREAPs)	–	EU Member States, summary by ECN, 2010	Aggregated policy plans (national modelling approach unknown)	2020	EU 27
EU energy trends to 2030	**Baseline** **Reference**	EC Directorate General for Energy (DG ENER), 2009	Combined (PRIMES model: macroeconomic equilibrium, behaviour and technological characteristics included)	2020 2030	EU 27
Power Choices	–	Eurelectric, 2011	Combined (PRIMES, Prometheus)	2020 2030 2050	EU 27
Pure Power	–	European Wind Energy Associaton (EWEA), 2011	Growth rate for one technology	2020 2030	EU 27
EU Energy (R)evolution	**Reference** **Basic** **Advanced**	Greenpeace & European Renewable Energy Council (EREC), 2010	Combined (MESAP/PlaNet simulation model: technology-driven but also including investment pathway and employment effects)	2020 2030 2050	EU 27, North Africa
Roadmap 2050	**Baseline** **60% RES** **80% RES**	European Climate Foundation (ECF), 2010	Top down (objective-driven scenario)	2020 2030 2050	EU 27

Many scenarios are based on combined **modelling approaches**, i.e. the models used include macroeconomic data as well as technology-specific and behavioural components. This approach has become increasingly popular over the last years as it combines the traditional bottom-up technology-based models with top-down economic equilibrium ones to provide a more realistic picture.

However, the **modelling results are influenced by assumptions** regarding fossil fuel prices, prices for carbon emissions, cost developments of renewable technologies, demand reduction, energy efficiency and electricity usage across all energy sectors, as well as grid and infrastructure constraints considered. Table 2 shows an overview of the assumptions used in the different scenarios. Especially high costs for fossil fuels and carbon emissions, in combination with decreasing costs for renewable technologies, lead to higher renewable shares as these become cost-competitive. Section 1.2 explains in more detail what cost-competitiveness means for different renewable technologies based on the voltage level at which they are fed into the grid.

Assumptions regarding the **oil price** developments over the next decades are especially influential but differ substantially across scenarios. The estimates should be compared to the current Brent crude oil price, which on November 24, 2011 was 107.58 $/barrel (corresponding to 80.72 €/barrel). Eureletric have considerably augmented their oil price assumptions compared to their previous scenario analysis (Roles of electricity, 2007) and now use an oil price of more than 100 $/barrel as of 2030. Their carbon price assumptions have also increased substantially compared to their previous estimate. The 2009 update of the EU Energy Trends includes an updated level of oil prices which is higher than the one used for the 2007 version. However, at 91 €/barrel it is still lower than actual oil prices today. The Roadmap 2050 projections assume oil prices at a similar level. The EU energy (R)evolution Scenario uses higher and probably more realistic developments for the oil price of over 100 €/barrel from 2020, in line with the sensitivity analysis of the IEA's World Energy Outlook 2009's higher sensitivity price. The EWEA Pure Power scenario uses oil price projections from the IEA's World Energy Outlook 2008 to calculate fuel savings by using wind energy, but also compares this development to the 2008 all-time maximum oil price of 147 $/barrel.

Another interesting aspect is the development of **CO_2 prices**. While Eurelectric assumes a constant price of 5 €/tCO_2 until 2030, the highest projection is used by the 2050 Roadmap projections at 110 $/t$CO_2$ corresponding to 77.77 €/tCO_2 using an exchange rate of €/$ 0.7503 (interbank exchange rate for November 24, 2011). This high carbon price, in combination with the relatively low price for fossil fuels, makes CCS technologies a viable option in the Roadmap 2050 scenarios.

Grid and infrastructure requirements are often mentioned in the scenarios but the investment needed is only rarely included into the modelling. This is important as the inclusion of grid constraints can potentially lead to lower estimates for the expansion of renewables, as those require more grid investment, which will be explored in detail in chapter 2.

Demand development is influenced by macroeconomic and population growth rates, but especially by the extent of improvements in energy efficiency and the assumed increased use of electricity in other energy sectors (transport and heat). As these assumptions vary across scenarios the predicted electricity demand changes as well.

Table 2: Assumptions used for the different scenarios

<table>
<tr><th>Scenario</th><th>General</th><th>Oil price</th><th>Carbon price</th><th>Technology costs</th><th>Demand development</th><th>Infrastructure constraints</th></tr>
<tr><td>Scenario Outlook and System Adequacy Forecast (Best Estimate)</td><td>Data from grid operators for development of resources, including existing plants and those with credible commissioning</td><td>Not mentioned</td><td>Not mentioned</td><td>Not mentioned</td><td>Demand growth rate 1.2% (2011 to 2015) and 1.4% (2016 to 2020)</td><td>Not mentioned but will be modelled in TYNDP plan 2012</td></tr>
<tr><td>National Renewable Energy Action Plans (NREAPs)</td><td>Combination of 27 NREAPs, realisation assumed</td><td>Not mentioned</td><td>Not mentioned</td><td>Not mentioned</td><td>Not mentioned</td><td>Not mentioned</td></tr>
<tr><td>EU energy trends to 2030 (Baseline)</td><td>2020 renewables targets not reached, policies included until April 2009, endogenous carbon price development</td><td rowspan="2">2020:
73 €'2008/bbl

2030:
91 €'2008/bbl</td><td>2020: 25 €'08/t CO_2

2030: 39 €/t CO_2</td><td rowspan="2">Learning rates and investment costs for RES not mentioned</td><td>Energy efficiency, hybrid and electric cars; growing electricity consumption</td><td rowspan="2">Technology portfolio includes advanced transmission and distribution grids and smart metering, grid expansion assumed and included in investment costs</td></tr>
<tr><td>EU energy trends to 2030 (Reference)</td><td>Achievement of 2020 objectives, all 2009 policies included, endogenous carbon price development</td><td>16.5 €'08/t CO_2 in 2020 and 18.7 €'08/t CO_2 in 2030</td><td>Intensified energy efficiency, lower increase in demand</td></tr>
<tr><td>Power Choices</td><td>Achievement of 2020 targets, 40% CO_2 reduction in 2030, 75% in 2050</td><td>2020: 88.4 US$'2008/bbl

2030: 105.9 US$'2008/bbl

2050: 126.8 US$'2008/bbl</td><td>2020: 25 US$'2008/t CO_2

2030: 52.1 US$'2008/t CO_2

2050: 103.2 US$'2008/t CO_2</td><td>Decreasing levelised costs for all technologies (higher reduction for solar and CCS), CCS commercially viable from 2025</td><td>Intensified energy efficiency, 90% electrification of transport sector by 2050, smart grids; in total increasing electricity consumption</td><td>Increasing load factor for electricity demand, 40% increase of interconnector capacity, additional costs for distribution networks and smart grids part of model</td></tr>
</table>

Pure Power	Historic growth rates, achievement of 2020 objectives assumed	According to WEO 2008 estimates: 2030: 122 US$'2007/bbl	Constant carbon price of 25 €/tCO_2	Long term downwards trend but with deviations according to supply-demand-balance	Electricity demand growth based on EC scenarios	Need for grid extension mentioned, incl. IEA projections for investment needs
EU Energy (R)evolution Scenario (Reference)	Success of current policies, dynamic market development	2020: 107.58 €'2005/bbl 2030: 124.13 €'2005/bbl	2020: 20 €/tCO_2 2030: 30 €/tCO_2 2050: 50 €/tCO_2	Learning curves based on studies and expert opinions		Qualitative description of the new grid including micro grids, a smart grid and an efficient large scale super grid, not part of modelling
EU Energy (R)evolution Scenario (Basic)	Reduction of CO_2 emissions to 970 mio t in 2050				Energy efficiency, decentralised generation	
EU Energy (R)evolution Scenario (Advanced)	Reduction of CO_2 emissions to 195 mio t in 2050, renewable industry market projections				Energy efficiency, electrification of heating and transport, smart grid, decentralised generation	
Roadmap 2050 (Baseline)	Growth of renewables share until 2030 than plateau, learning curves	2015: 87 $/barrel from 2030: 115 $/barrel	2015: 43 US$/t$CO_2$ 2030: 54 US$/t$CO_2$	Learning rates: 5% wind onshore and offshore, 15% solar PV	Steady increase to 4,800 TWh in 2050	Modelling of infrastructure and associated costs included in optimisation and influencing geographical distribution of generation units
Roadmap 2050 (60% RES)	80% reduction of carbon emissions, European cooperation		2020: 50 US$/t$CO_2$ from 2030: 110 US$/t$CO_2$		Energy efficiency improvements but fuel shift in heating and transport sector, thus increase to 4,900 TWh in 2050	
Roadmap 2050 (80% RES)						

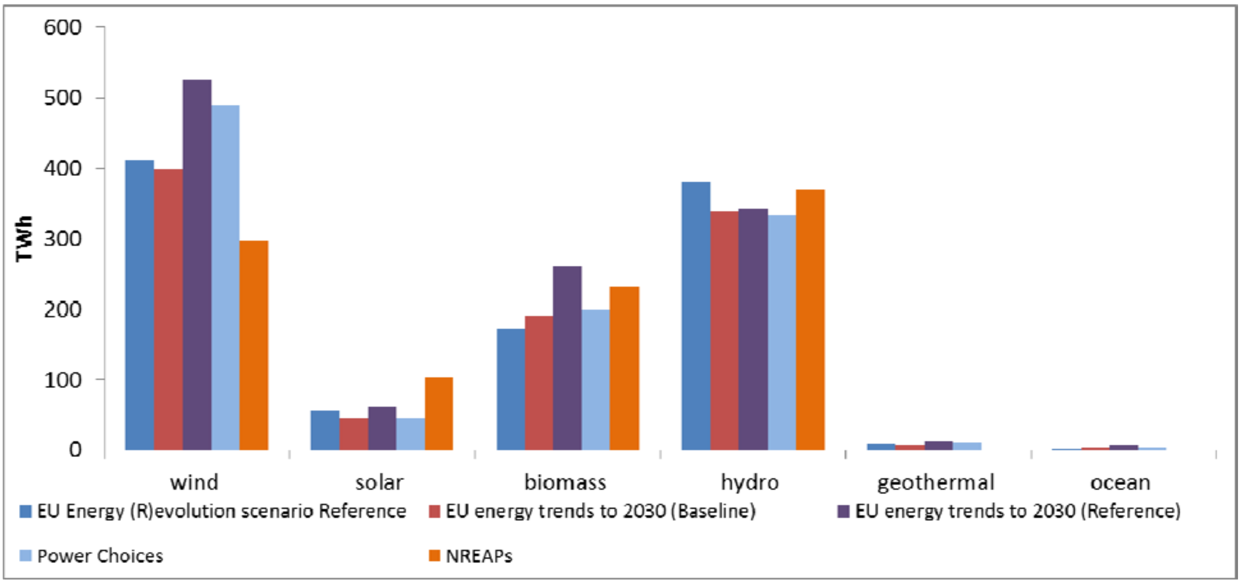
1.1.2. Differentiation by renewable source and over time

This section gives an overview of renewable power generation and installed generation capacities for the years 2020, 2030 and 2050, differentiated as far as possible by generation technology, i.e. solar (PV and solar thermal power), wind (onshore and offshore), biomass, ocean, hydro and geothermal power generation.

The following figures show the values for electricity generation (TWh) and installed renewable capacity (GW) by technology for 2020, 2030 and 2050, respectively. Data are used from all available scenarios. In order to show absolute values and the contribution of the different technologies, the above listed scenarios are grouped into baseline and high renewables scenarios for 2020, 2030 and 2050. As explained above, the differences in geographical coverage are not considered in this section.

2020 scenarios

Figure 1: Total renewable electricity generation and installed capacity 2020 in different baseline scenarios



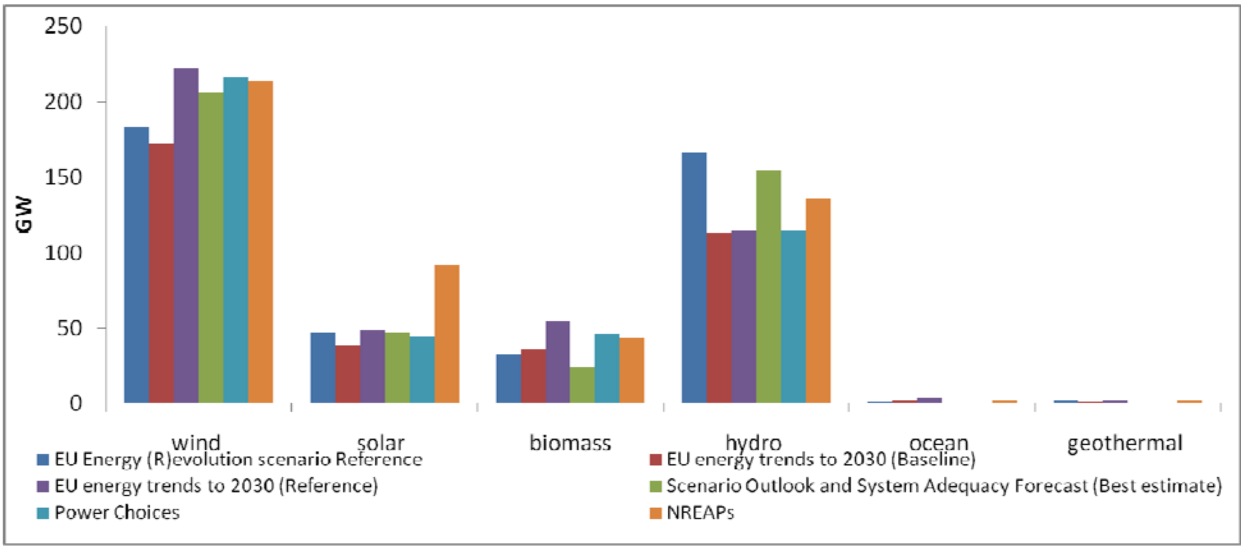


Figure 1 shows that **baseline projections for 2020** are relatively similar in all scenarios, in terms of both production and installed renewable capacity. The installed solar capacity planned for in the National Renewable Energy Action Plans (NREAPs) is considerably higher than in other estimates. The EC as well as Eurelectric (both using the Primes model) assume a high generation from wind. Both points are interesting as the EC suggests using the Reference case as a basis for projections [European Commission 2010a, chapter 4], while the NREAPs reflect EU Member States' actual planning as to how to fulfil the EU renewable energy targets by 2020. It is recommended that developers of scenarios take more account of the NREAPs for future scenario building. On the other hand, both Member States' support programmes for solar power are changing and PV costs continue to decrease strongly, which makes solar power development difficult to project. The estimate for hydro power capacity is comparatively high in the EU Energy (R)evolution Scenario, but almost as high as the one used by ENTSO-E and is therefore still in a realistic range.

Figure 2: Total renewable electricity generation and installed capacity 2020 in different high renewables scenarios

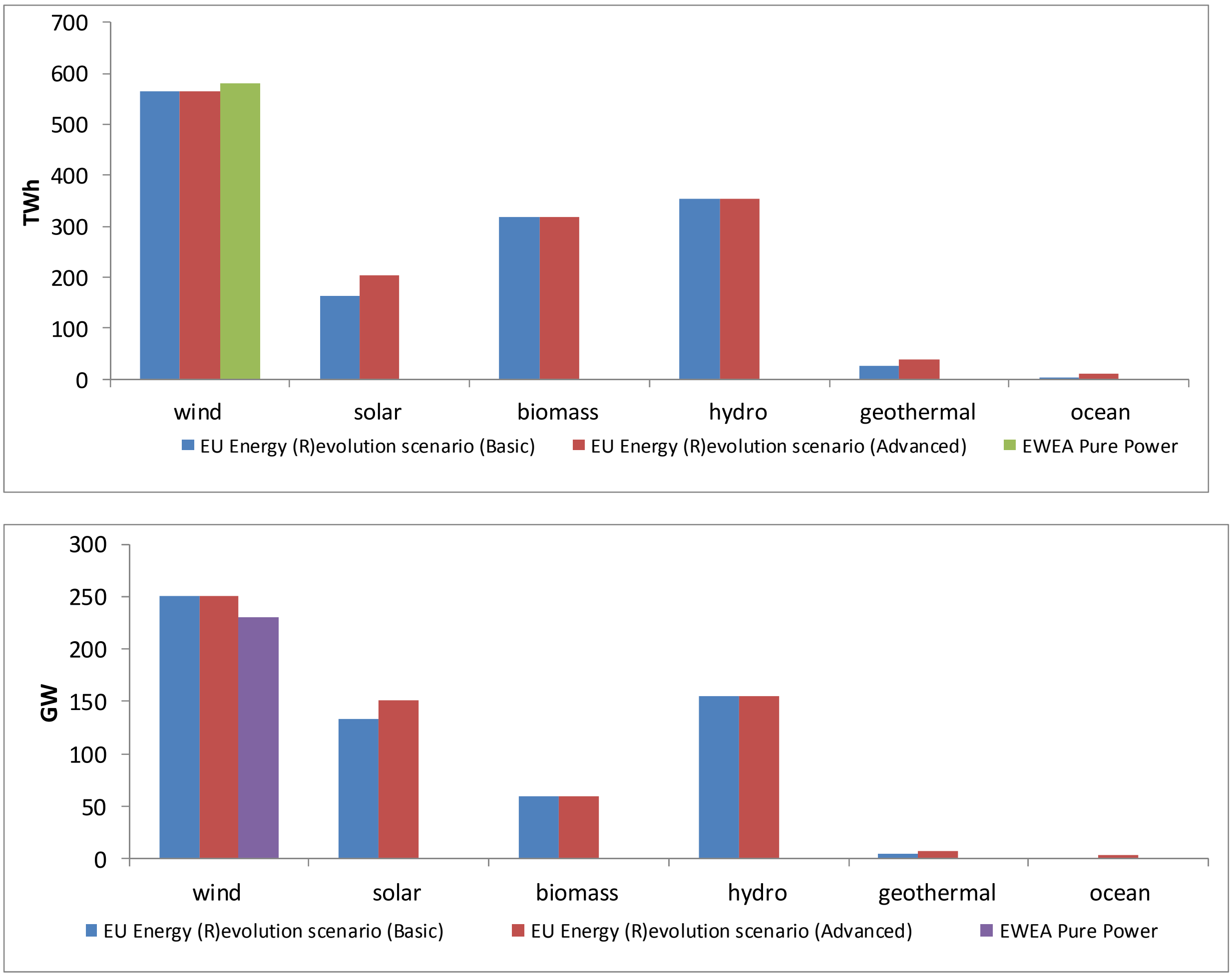
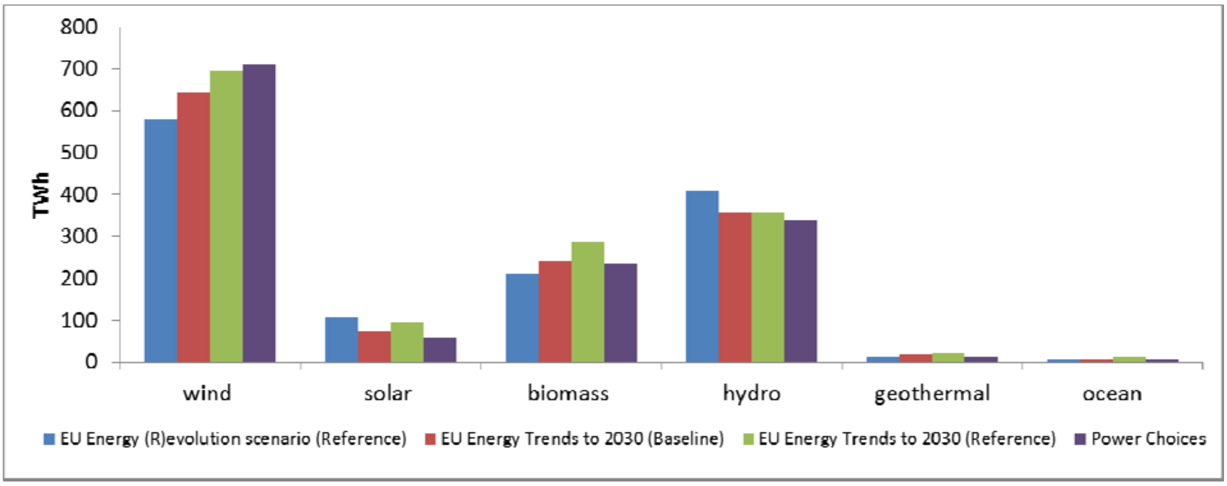


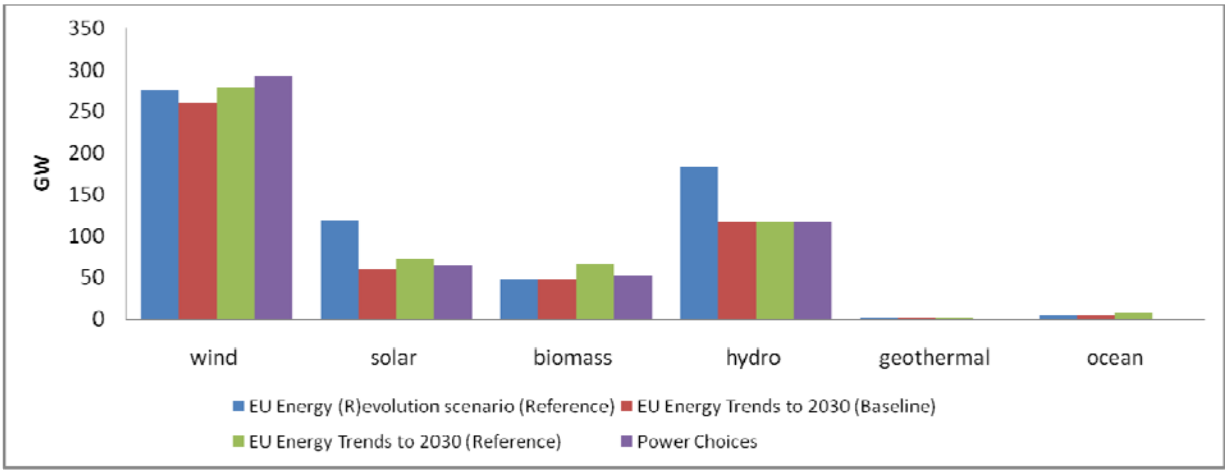
Figure 2 shows the same estimates for 2020 using the **high renewable scenarios** listed in the figure. Differences between the various estimates are low here as well. However, only a few high renewable scenarios provide data for 2020. Overall, the installed renewable capacity in the high renewable scenarios is 583.3 GW on average, compared to 450.7 GW in the baseline scenarios and thus around 29.4% higher; electricity generation averaged from the scenarios included is around 9% higher in the high renewables case. The increase is mostly due to higher electricity generation from wind and solar.

2030 scenarios

Figure 3 shows the **baseline values for 2030**. The average installed renewable capacity in these scenarios is 581 GW, the average electricity generation from renewables is 1365 TWh. The figure shows that, for 2030, the EU Energy (R)evolution scenario assumes a relatively high generation and installed capacity from solar sources. However, considering the NREAPs forecast of installed solar capacity in 2020, such a development seems feasible.

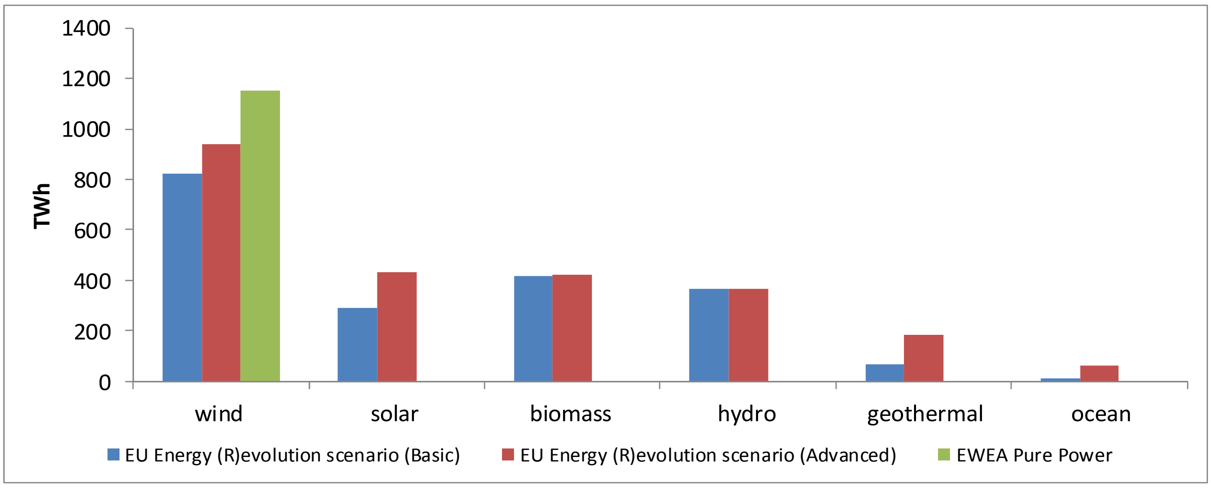
Figure 3: Total renewable electricity generation and installed capacity 2030 in different baseline scenarios

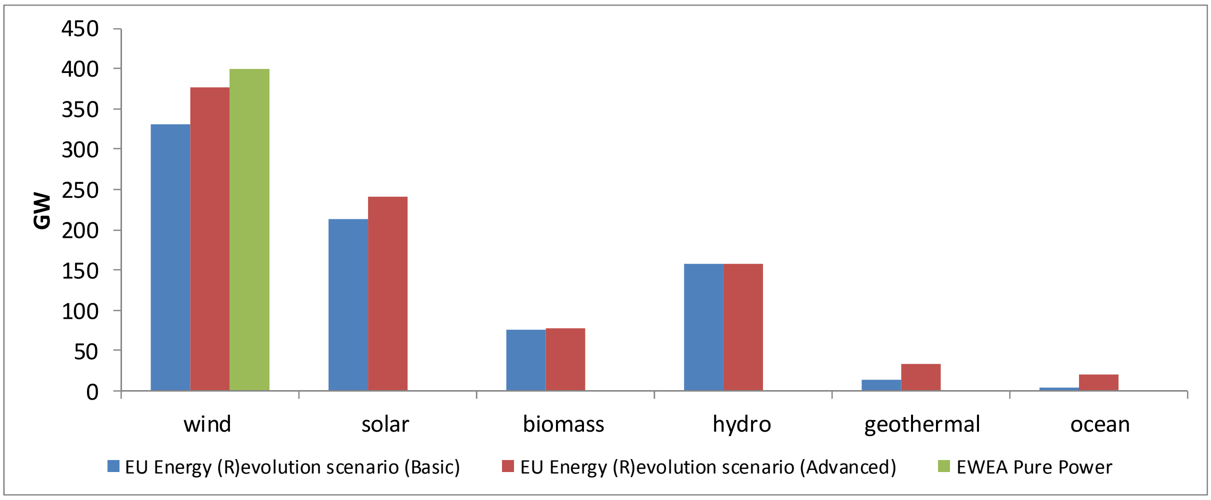




Unfortunately, only the two EU energy (R)evolution scenarios and the EWEA Pure power objectives for wind development are available as **high renewable scenarios for 2030** (see Figure 4). Contrary to 2020 values, the EWEA projection of growth in wind power is higher than the EU Energy (R)evolution estimates.

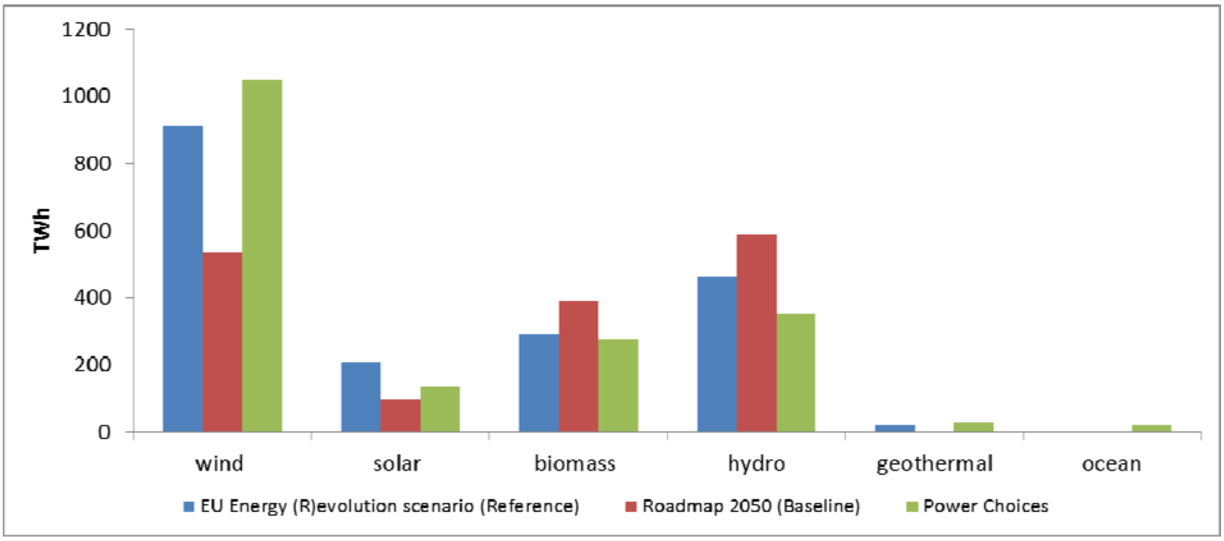
Figure 4: Total renewable electricity generation and installed capacity 2030 in different high renewables scenarios





2050 Scenarios

Figure 5: Total renewable electricity generation and installed capacity 2050 in different baseline scenarios



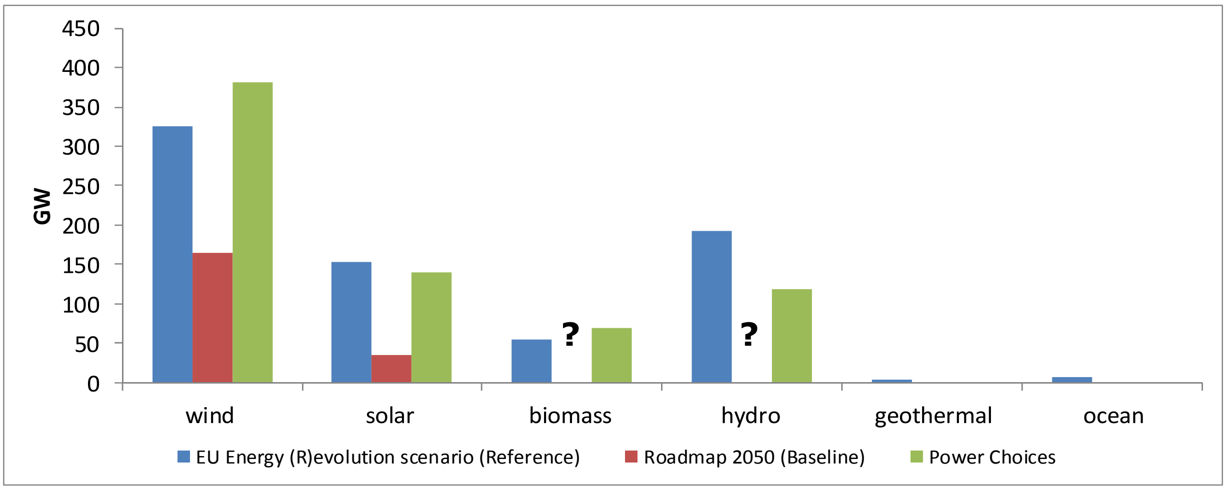
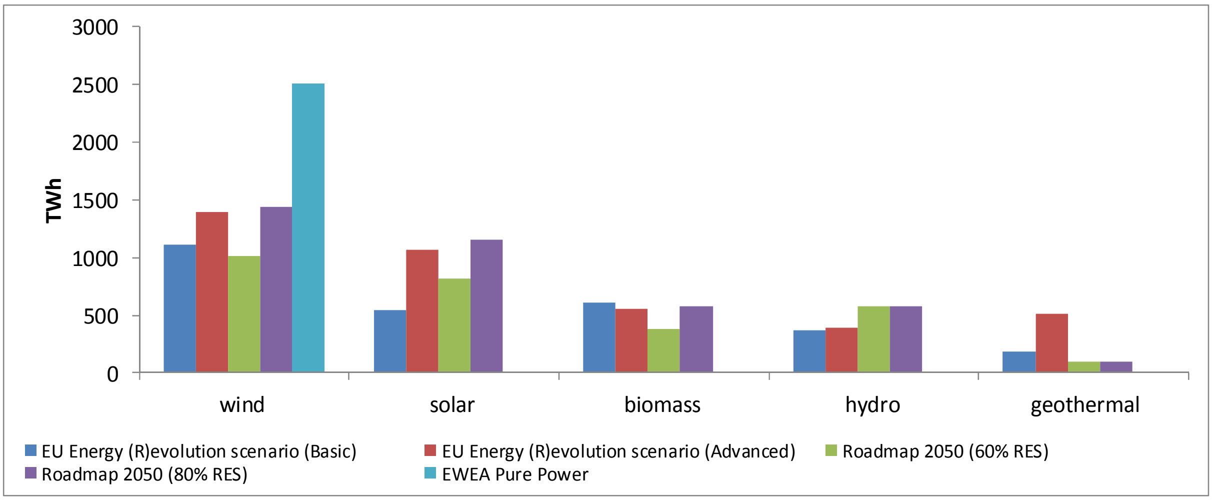


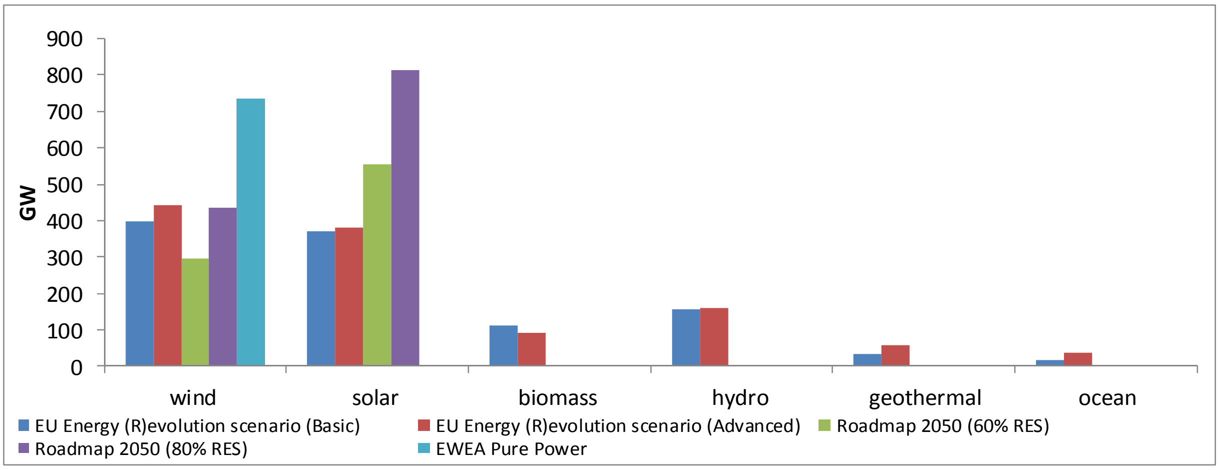
Figure 5 shows the **baseline scenarios for 2050**. Interestingly, the Roadmap 2050 (Baseline) assumes much lower values for both solar and wind power generation, but higher contributions from biomass and hydro power[8]. The renewables share in electricity generation for this scenario is 34%, which is not much lower than that in the Power Choices scenario (40%).

Surprisingly, the differences between **high renewables scenarios for 2050** are not considerably higher than in the baseline case. The much higher EWEA target values are not taken into consideration here as they are simply based on a targeted 50% wind share in electricity generation. Nevertheless, wind capacities range between 295 and 497 GW, and solar PV installation between 340 and 815 GW. Contrary to the baseline, solar PV installation is higher than wind capacity in the Roadmap 2050 scenarios with a high share of renewables. Electricity generation from PV, however, is still lower than wind electricity generation. Geothermal, ocean and solar thermal electricity generation become relevant in the EU Energy (R)evolution scenarios. [ECF 2011] do not provide data for these technologies.

Figure 6: Total renewable electricity generation and installed capacity 2050 in different high renewables scenarios



[8] Roadmap 2050 only provides a combined value for hydro power and biomass generation; therefore, Figure 5 does not display separate values.



As illustrated by the figures, all the analysed scenarios show **varying values for both electricity generation and installed capacity** for renewable technologies. Different technologies have different characteristics regarding size and generation pattern, which results in a diverse mix of decentralised and centralised electricity generation, and of intermittent and non-intermittent production. Therefore, infrastructure requirements for each of the scenarios differ considerably. As stated above, deviations are relatively small for 2020 and projections for grid extensions for this period can be relatively reliable. Divergence increases with the time horizon.

Figure 6 and Figure 7 depict the development of **total electricity generation and installed capacity** in all scenarios analysed over time. The EWEA Pure Power scenario is not included in Figure 7 as it only considers one technology.

For the **baseline scenarios**, it is interesting to see that most of them assume a relatively constant absolute contribution to electricity production from conventional sources, while renewable generation is increasing over time.

The **high renewables scenarios** show of course a higher contribution of renewables to the overall electricity production. In addition, in most cases the total electricity production is not growing at the same rate as in the baseline scenarios (the exception being the Roadmap 2050 scenarios). This lower expansion is due to the increase in energy efficiency assumed in these scenarios.

In terms of **installed capacities**, there are several interesting developments. In the Pure Power scenario as well as in the Energy (R)evolution baseline, absolute values for conventional capacities first decrease, but increase again after 2030, probably because of the extension of nuclear power plants and the availability of CCS[9]. Gas-fired generation becomes considerably more important over time. The EC energy trends baseline predicts a growth in conventional capacities and renewables until 2030; in the reference case, conventional capacities remain relatively constant, with a structural change towards gas-fired generation, while renewable capacity increases more extensively. For the Roadmap 2050 scenarios, conventional capacity includes all technologies except solar and wind, as separate data for the other renewables are not available.

[9] Scenarios have been modelled before Fukushima. The trend is towards phasing out nuclear power across France, Germany, Belgium, etc.

It also becomes clear from the picture that, as in the generation case, installed capacity is supposed to be much higher in the Roadmap 2050 reduced emissions scenarios than in the EU Energy (R)evolution projections. In the EU Energy (R)evolution scenarios, the lower expansion of capacity needed is again linked to increased energy efficiency, as well as to the uptake of smart grid infrastructure and demand side management.

Figure 7: Development of total electricity generation in assessed baseline and high renewables scenarios over time

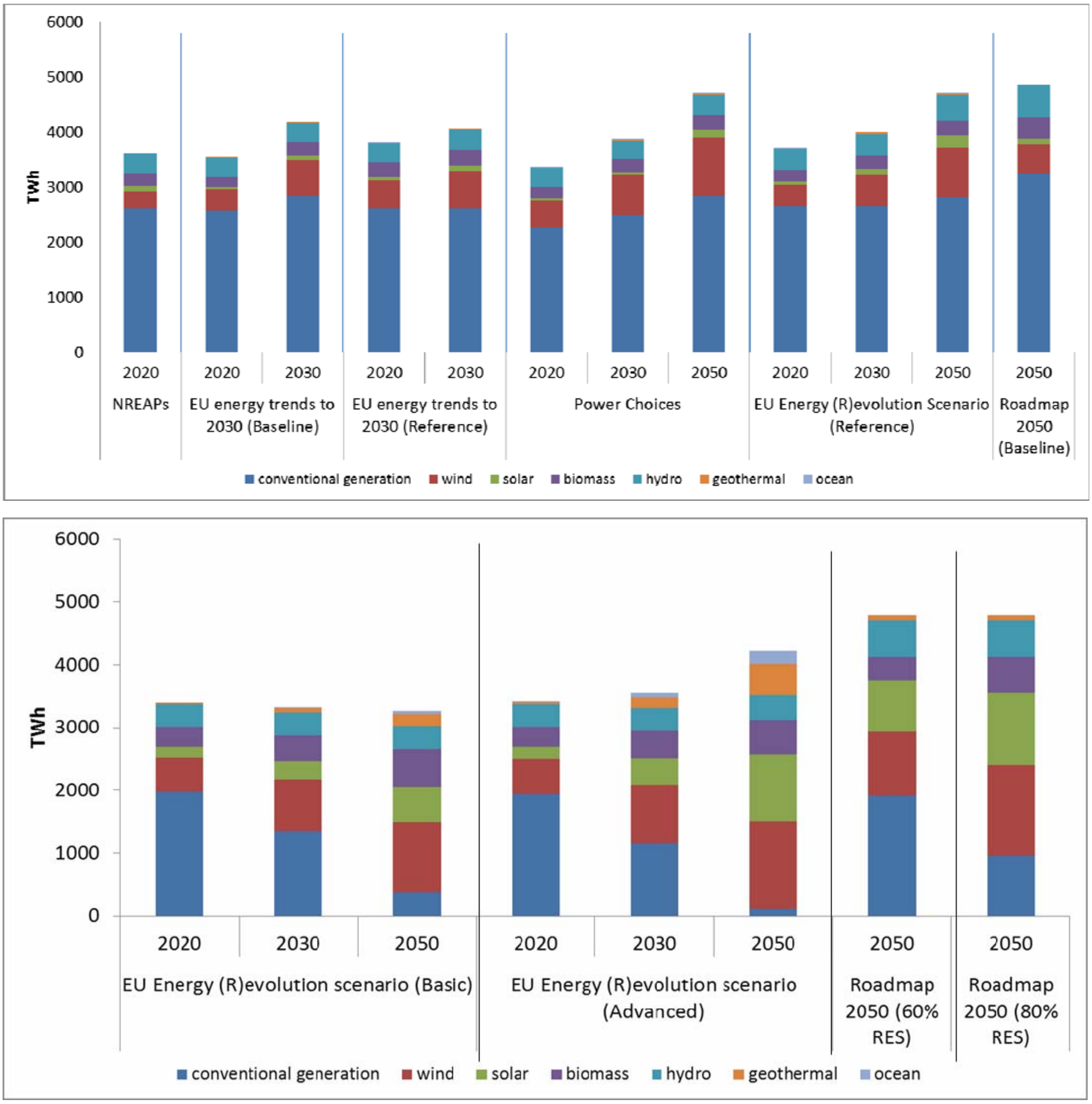
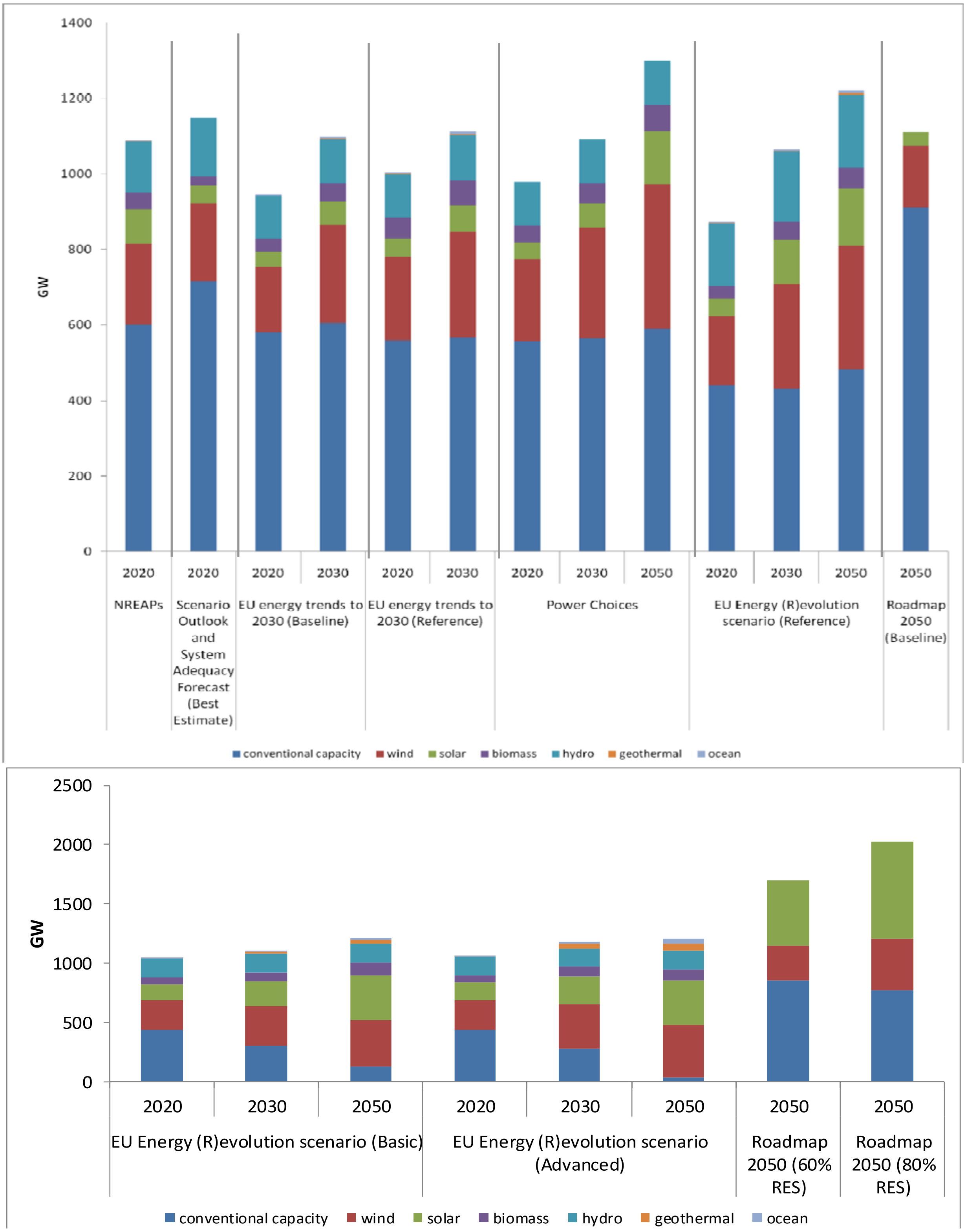


Figure 8: Development of installed capacity in assessed baseline and high renewables scenarios over time[10]



[10] For the Roadmap 2050 Scenarios, conventional capacity includes all technologies apart from wind and solar as there are no separate data available for biomass, geothermal, ocean or hydro power capacity.

1.1.3. Definition of study BASE and RES scenario

In the context of our analysis, and within the set of those scrutinised in chapter 1.1.1, the most representative **"baseline scenario" (BASE)** – assuming the continuation of current policies – and **"high renewables scenario" (RES)** – including more ambitious renewable energy or environmental policy targets – have been found to be the EU Energy (R)evolution "Reference Scenario" and the EU Energy (R)evolution "Advanced Scenario", respectively. This choice has been made based on the following characteristics of the two (R)evolution scenarios:

1. The **assumptions** regarding fossil fuel prices, the price for carbon emissions and the cost development of renewable energy technologies seem to be based on a comprehensive process, i.e. literature research plus expert review.

2. For 2020, **electricity production** in the Reference Scenario is between the NREAPs and the EC's trends to 2030. Thus, it assumes some progress regarding energy efficiency but not that all EU 2020 targets are reached, which is fitting with the trend as energy efficiency targets will be very difficult to reach by 2020 at current (non-)progress rates. EU Member States have missed their 2010 energy efficiency targets by far. The Reference Scenario also does not deviate much from other baseline scenarios for 2020 or 2030, regarding installed renewable capacities or electricity generation. For 2050, only the baseline of Roadmap 2050 is available, which is based on very different assumptions (high carbon price, comparatively low fossil fuel prices, higher learning rates for CCS than for wind power), resulting in a much lower share and absolute values for renewables. Total electricity generation and installed capacity, however, are not too different, which means that the Reference Scenario's assumptions regarding demand development seem to be widely shared and not unrealistic.

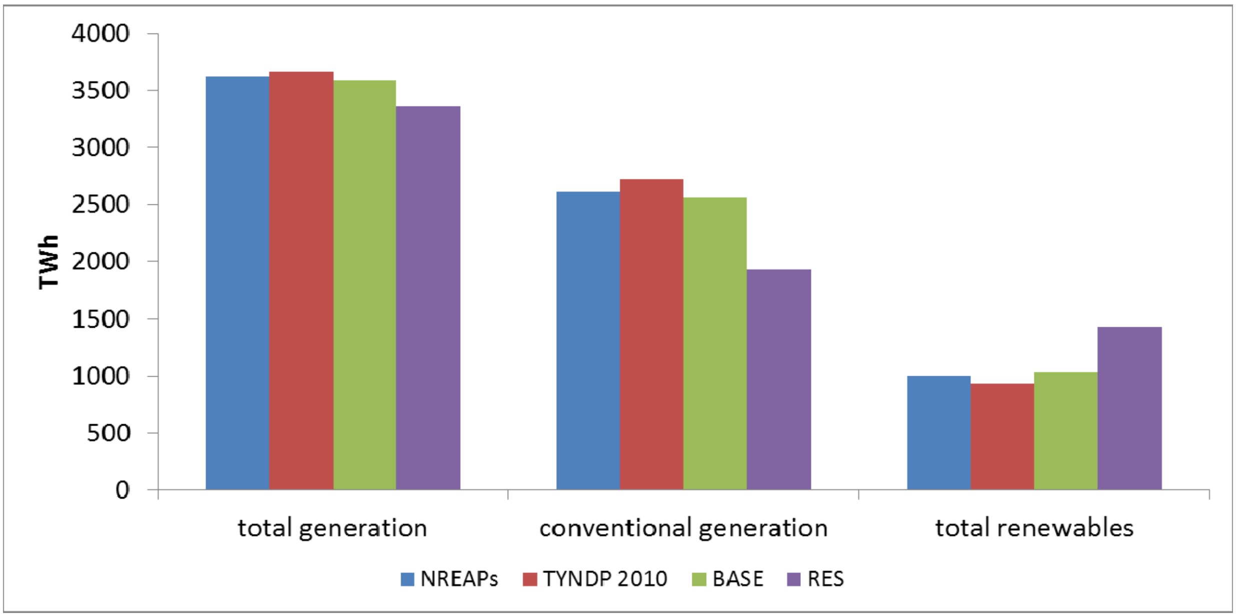
3. The Advanced Scenario can unfortunately only be compared to the apparently less ambitious Basic Scenario and the EWEA projections for 2020 and 2030. Assumptions regarding wind power are however consistently below EWEA estimates. When looking at 2050 renewables generation and installed capacity, both are lower than in the Roadmap 2050 80% RES case. Therefore, the **expansion of renewable electricity** assumed in this scenario seems to be feasible.

4. The **share of renewable electricity** in this scenario is high, at 98% of electricity production compared to other scenarios. Given the urgency of both climate change mitigation and the need to minimise dependence on fossil fuels, it makes sense to use such a scenario as RES scenario. However, projections in the Advanced Scenario are significantly lower than Roadmap 2050 estimates in absolute terms of total installed capacity and electricity generation in 2050, because ambitious energy efficiency improvements and demand reductions are assumed beyond 2020.

5. More **practical advantages** of the EU Energy (R)evolution models are that full data for both generation and capacities are available across the whole time span included in the report; and a relatively good compatibility of the BASE scenario with ENTSO-E's Ten-year network development plan 2010 [TYNDP 2010], as well as the NREAPs, as shown in Figure 9. However, the contribution of wind and solar to total generation from renewables varies from the NREAPs to the EU Energy (R)evolution model, as the NREAPs assume a much higher solar penetration but a lower share for wind energy. This study nevertheless uses the EU Energy (R)evolution scenario, both to ensure consistency and because it is expected that investment in wind projects will be far higher than for PV, at least for the current decade.

The only disadvantage of the Energy (R)evolution scenarios is that wind energy is not split into onshore and offshore, although this distinction is crucial for deriving infrastructure needs. Therefore, the share of offshore and onshore needs to be obtained from other scenarios.

Figure 9: Comparison of 2020 electricity generation between the selected BASE and RES scenarios, the NREAPs and the assumptions used in the TYNDP 2010



1.2. Small versus large scale renewable energy deployment

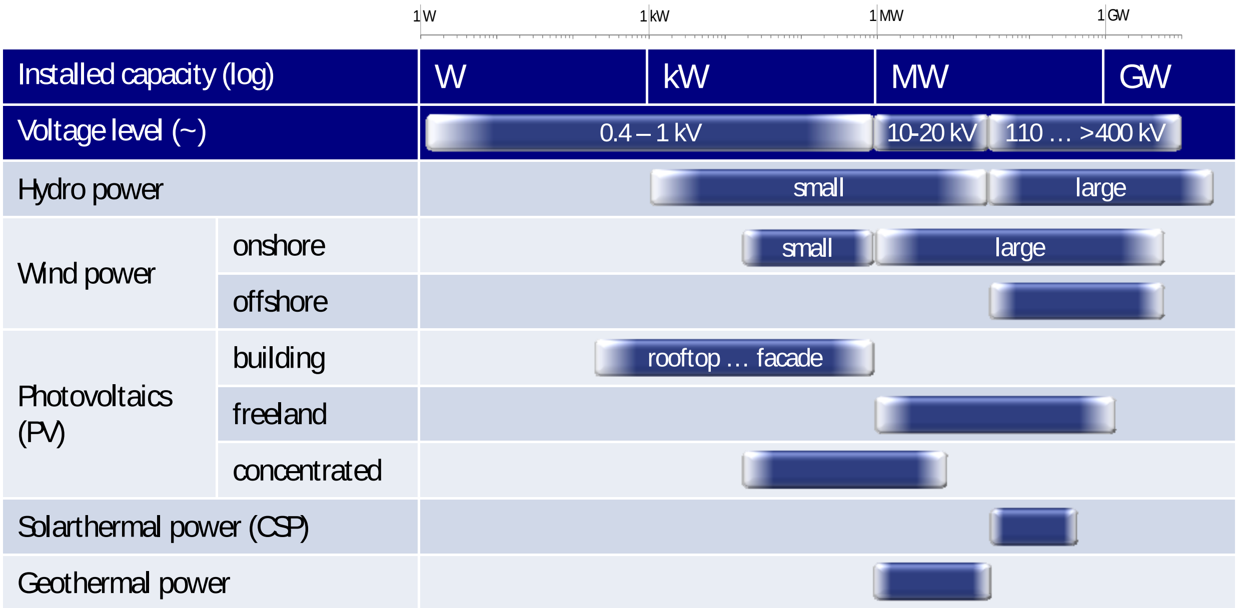
The extent to which the expansion of renewable power generation will require grid enhancement and energy storage strategies depends, among other factors, on how much renewable energy production will be done on a small (decentralised) or large scale (centralised). In a nutshell, the more **decentralised** the energy generation is and the better it fits with local energy consumption, the fewer energy **transport capacities** will be required. Local energy storage can serve as an intermediate between local supply and demand. Central energy storage at places off from the centres of RES production, e.g. renewable energy from Central Europe to be stored in pumped hydro power plants in Norway, would require additional power transmission capacity.

Renewable energies are by nature more dispersed than fossil or nuclear energy sources. Mines, oil and gas wells constitute highly concentrated sources of primary energy which were accumulated over million years through biological and geophysical processes. What are the consequences of a **transition from fossils and nuclear fuels to renewable energy sources?**

- Small scale, decentralised renewable energy sources like PV and wind power have to be collected and mixed to increase the security of supply and to reduce energy storage needs;
- Large scale, centralised renewable energy sources like large hydro, wind power parks, or solar thermal power, are usually not located at the centres of energy consumption. The renewable energy thus has to be transported from supply to demand centres.

The **mix of small versus large scale** and other options, such as demand-side management and storage (see separate chapters on both), determines the need for grid enhancements. Unfortunately, the scenarios assessed in chapter 1.1.1 do not provide much detail on this important aspect. Nevertheless, some technologies – such as offshore wind or solar thermal power – can be categorised in this respect. Figure 10 gives an overview of installed renewable power capacities and grid connection levels, based on currently typical ranges and foreseeable future developments in installation sizes.

Figure 10: Bandwidths of installed capacities of renewable power sources (logarithmic scale) and grid connection levels, differentiated by renewable energy technology



Source: LBST

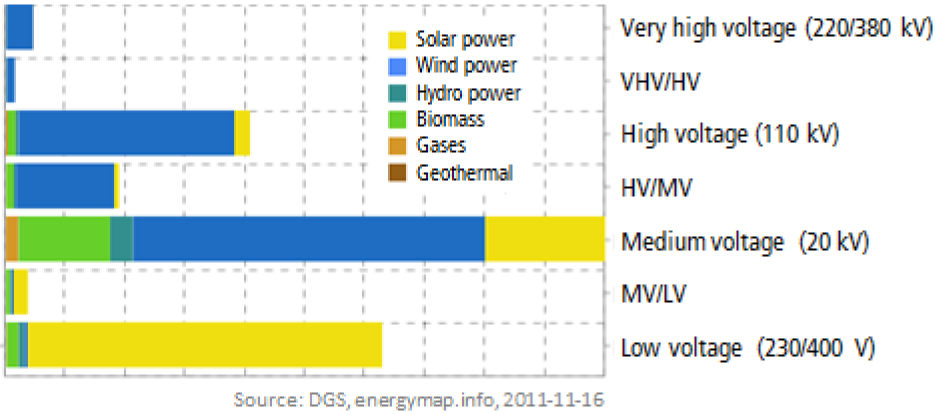
The actual distribution and pace of deployment of small versus large scale renewable power technologies strongly depend on **local specificities**. The most important parameters are the local renewable energy potentials, the promotion instruments and the regulatory framework for the deployment of renewable power sources. Those parameters shape investment decisions and thus the relative preference of e.g. rooftop versus freeland systems in the case of PV.

Case study: Renewable power capacities connected to the grid in Germany

In absolute terms, Germany has the highest stock of power generation capacities from new renewable sources (wind, PV) in the EU. In addition, all different types of renewable power sources have been deployed in Germany, apart from solar thermal power plants[11]. Therefore, Germany is a good example to get an impression about how and where deployment of renewable power capacities is taking place, especially with a view to small versus large scale. Figure 11 illustrates which renewable power capacities are connected to what voltage grid level in Germany. The lower the grid level, the smaller (i.e. more decentralised) is the power generation type.

[11] Solar thermal power plants require direct solar radiation, which is predominantly available in Southern Europe.

Figure 11: Distribution of installed renewable power generation capacities by grid voltage level



Source: [DGS 2011]

As shown in Figure 11, in the case of Germany wind power is predominantly connected to the higher voltage levels (the transmission grid, i.e. centralised) down to the 20 kV~ level. Hydro power is mostly found at the 20 kV~ medium voltage level. Photovoltaics is predominantly connected to low and medium voltage levels (the distribution grid, i.e. decentralised).

For a further discussion of decentralised versus centralised power plants, see [Altmann 2010a].

Grid parity

The so-called "grid parity" is reached when the renewable electricity **costs break even** with the cost of electricity from the grid mix. "Grid parity" can become a game-changer in the energy sector.

Usually, prices at the **power exchanges** are the focus of discussion on the economic viability of different types of power generation. However, due to the deregulation of the EU's internal electricity market, there is no single power market anymore along the value chain of power generation, trading, transport and distribution. Depending on the voltage level and electricity volume demanded, there are in fact different power markets that renewable electricity generation can supply:

- Power exchange / large industry consumers at (very) high voltage levels;
- Medium sized industry and commerce at medium to low voltage levels;
- Small commerce, services and households at low voltage level.

In niche markets, grid parity is near or has already been achieved. In sun-rich countries with high electricity prices, **photovoltaic (PV) power** is already cost-competitive under off-grid conditions, i.e. when there is no grid nearby or connection to the grid is too costly.

More and more renewable energy technologies will break even in the different power markets in this decade, thanks to cost reductions deriving from mass production and further technological developments, as well as cost increases on the side of fossil fuels, and compliance requirements with environmental targets.

In an analysis of the five major solar **PV markets in Europe** (France, Germany, Italy, Spain, United Kingdom), the European PV Industry Association expects grid parity to be achieved at all power levels in this decade [EPIA 2011]. In an analysis of **global PV markets**, [Breyer 2011] concludes that "at the end of this decade more than 80% of market segments in Europe, the Americas and Asia are beyond residential grid-parity. Due to energy subsidies in South Africa and Egypt, which represent more than 60% of African electricity generation, Africa is an exception in this point."

Note that grid parity is calculated assuming **preferential feeding into the grid**, i.e. accounting for the whole amount of possible annual power production from the renewable source. This means that, when passing the break-even of this simple grid parity, support frameworks for wind and photovoltaic will not immediately become void. For example, in the case of residential PV, only some 20-30% of the PV electricity produced can be consumed in the household without additional measures. In order to significantly increase **own consumption**, measures are to be taken, such as demand side management (be they 'smart' or not), stationary batteries, vehicle home-charging (in the case of battery electric vehicles) or vehicle home-refuelling (in the case of hydrogen fuel cell vehicles). For this, additional investments are required, which only pay off as soon as a sufficient margin is achieved after grid parity.

Increasing shares of renewable electricity will require increasing **management measures**, such as grid enforcement, demand side management and energy storage. This will damp the cost reduction trajectory. However, the remaining power production from fossil and nuclear energy will conversely rise in price as their utilisation starts decreasing.

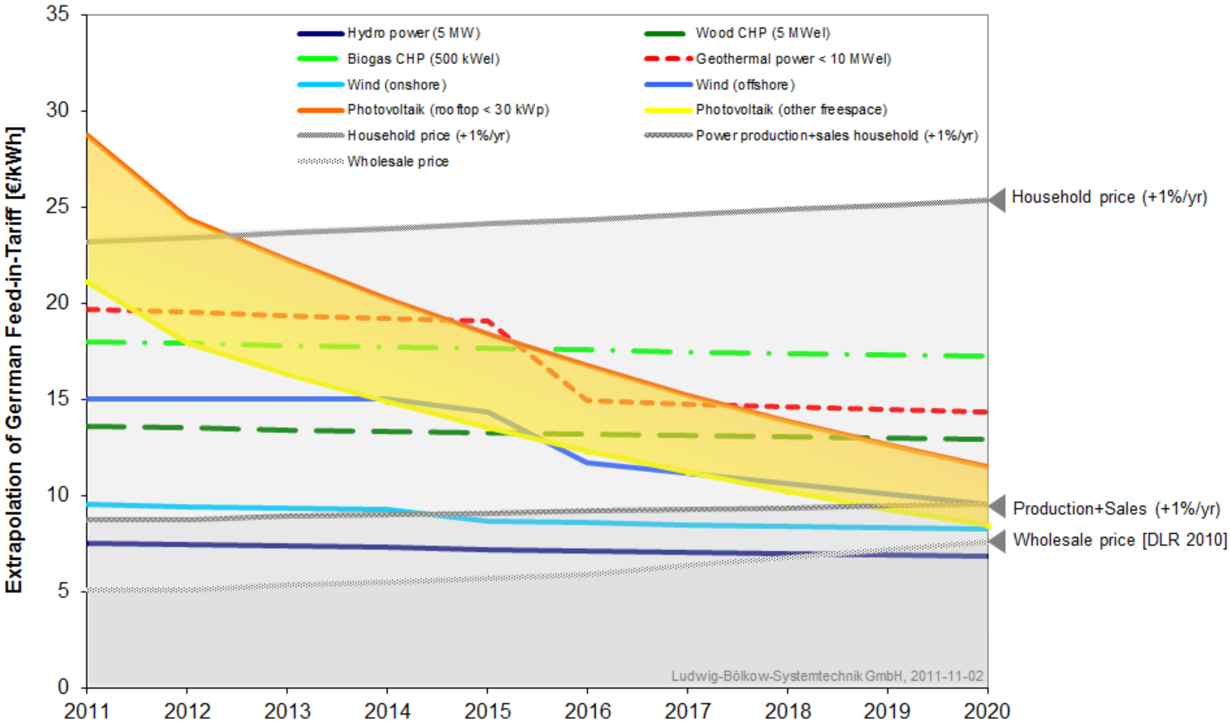
The **dynamics** in future developments are set to increase. The energy sector will certainly become much more diverse, not only in terms of energy supply mix, but also with regard to investors (private, co-op, communal, institutional). How this dynamics will materialise is to a great extent a matter of how regulatory frameworks will shape the market, e.g. through technical grid connection codes or market opening to small power producers. Chapters 3.4.1 and 4 are looking into various regulatory aspects.

Case study: Grid parity of electricity from renewable sources in Germany

The development of German feed-in-tariffs is shown in Figure 12 as an example of a Central European Member State. The development of electricity prices at different power markets is depicted in the same chart, assuming a rise in electricity prices of 1% per year.

As can be seen from Figure 12, "grid parity" for households and small commerce in Germany will very likely be achieved with **rooftop PV** systems already in the first half of this decade. **Onshore wind** at medium voltage levels will reach grid parity by the middle of the current decade, possibly even before if we consider the development of onshore towers of 150 m and above, as this results in energy yields close to offshore conditions. **Offshore wind** will probably reach bulk power grid parity – i.e. generation cost at (very) high voltage levels – by the end of the decade.

Figure 12: Grid parity this decade – Extrapolation of Feed-in-Tariffs (FiT) vis-à-vis different power market prices in Germany until 2020



Source: LBST compilation based on EEG data

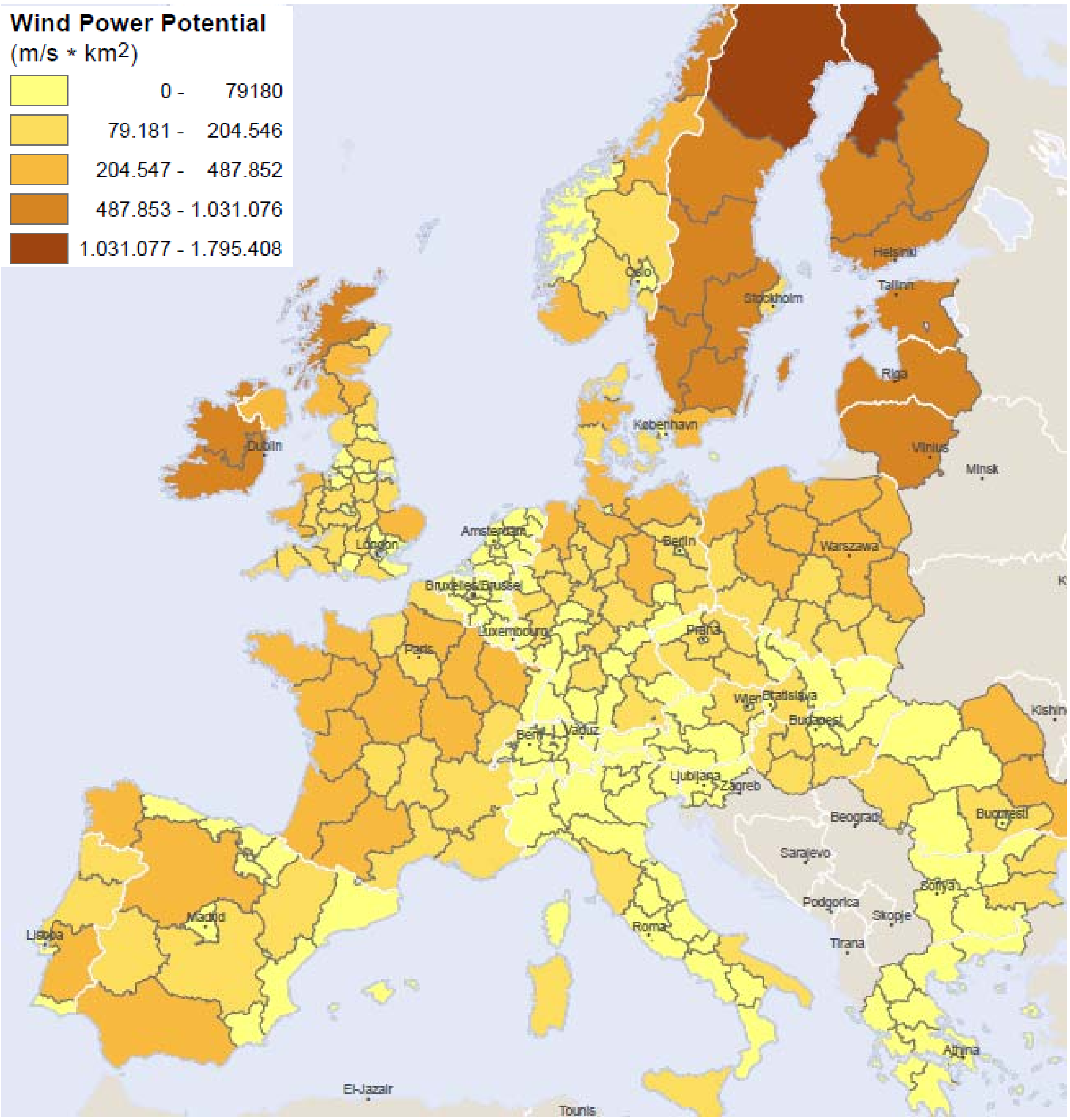
1.3. Geographic distribution

This section provides a breakdown of the geographic distribution of renewable sources in Europe and its neighbouring countries.

1.3.1. Wind

Onshore wind power conditions are most favourable along the coastlines, including up to several hundreds of kilometres into the greater hinterland. Wind installations are becoming increasingly attractive even under unfavourable conditions, such as in forests or less mountainous regions, thanks to towers of over 100 m. With greater heights, in fact, wind speeds increase exponentially, and the turbulences caused by surface roughness are significantly reduced. This allows for acceptable annual full load hours even in forest areas. The future onshore wind power generation can thus be considered rather evenly distributed over the continent. A recent analysis of physical wind power potentials in Europe is shown in Map 1.

Map 1: Onshore wind power potentials in EU regions



Source: EU project "ESPON ReRisk"[12] as of 2010 with wind intensity data from ETC/ACC as of 2009

Offshore wind power is obviously placed near the shorelines or further into the sea. Depending on water depth and foundation technologies, this can be up to 100 km and further offshore (see German North Sea), and in the future it could even take the form of free-floating wind turbines. Map 2 depicts the physical wind power potentials of European seas.

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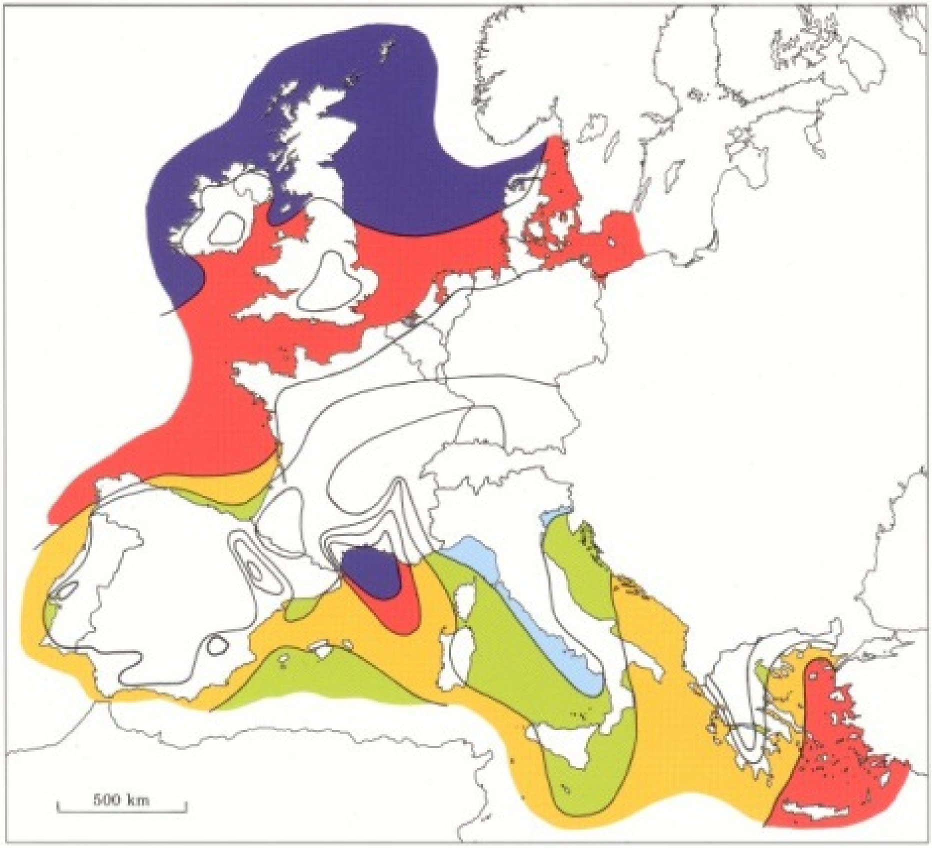
[12] http://www.espon.eu/main/Menu_Publications/Menu_MapsOfTheMonth/map1101.html

Map 2: European wind resources over open sea



Wind resources over open sea (more than 10 km offshore) for five standard heights										
	10 m		25 m		50 m		100 m		200 m	
	$m s^{-1}$	$W m^{-2}$	$m s^{-1}$	$W m^{-2}$	$m s^{-1}$	$W m^{-2}$	$m s^{-1}$	$W m^{-2}$	$m s^{-1}$	$W m^{-2}$
	> 8.0	> 600	> 8.5	> 700	> 9.0	> 800	> 10.0	> 1100	> 11.0	> 1500
	7.0-8.0	350-600	7.5-8.5	450-700	8.0-9.0	600-800	8.5-10.0	650-1100	9.5-11.0	900-1500
	6.0-7.0	250-300	6.5-7.5	300-450	7.0-8.0	400-600	7.5- 8.5	450- 650	8.0- 9.5	600- 900
	4.5-6.0	100-250	5.0-6.5	150-300	5.5-7.0	200-400	6.0- 7.5	250- 450	6.5- 8.0	300- 600
	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 6.0	< 250	< 6.5	< 300

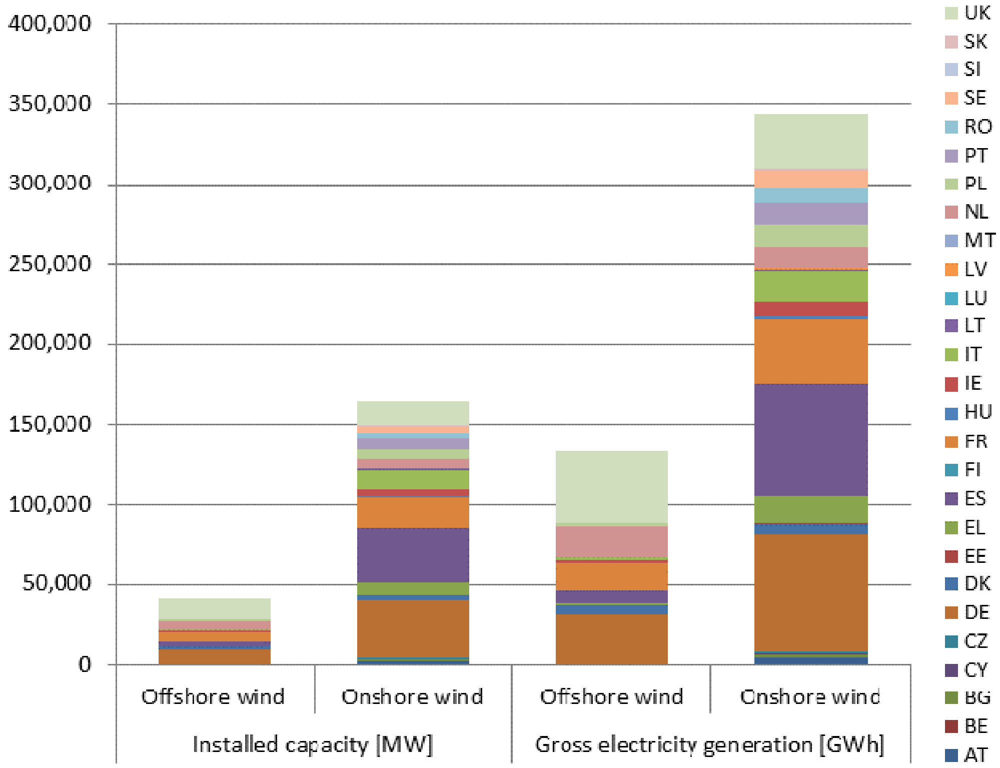
Source: [European Wind Atlas[13] as of 1989]

Short term plans for the deployment of wind power in EU Member States are laid down in the **National Renewable Energy Action Plans (NREAPs)** (see Figure 13).

Over the past decade, assumptions on the growth of power generation from renewable sources have been regularly on the conservative side. Below is, for comparison, the latest position of EWEA on the future build-up of wind power capacities in Europe. In 2010, wind power provided some 5% of the EU 27 electricity consumption. All scenarios including EWEA anticipate major future contributions to EU electricity production to come from wind. Table 2 shows the possible **contributions by 2020** assumed by EWEA, for each Member State. In general, this is consistent with the NREAPs; however, EWEA assumes higher wind shares for most MS resulting in an overall higher wind share in 2020 (see chapter 1.1.2).

[13] http://www.windatlas.dk/europe/oceanmap.html

Figure 13: Wind power capacities and generation according to EU Member States NREAPs for 2020



Source: LBST based on data from [ECN 2011]

While the **NREAPs** foresee an overall 206 GW of installed wind power capacities (both onshore and offshore) in Europe by 2020, EWEA expects some 230 GW, mostly because of higher expectations for the deployment of onshore wind. Onshore wind will likely dominate for another decade (see Table 3). Until 2030, the majority of wind energy will still be provided by onshore wind parks. After 2030, the major contribution may come from offshore wind sources, which because of the long time horizon is difficult to project. The wind capacity assumed by EWEA for 2050 is significantly higher than assumed by the other scenarios, which is mainly attributable to the development of offshore wind after 2030.

Table 2: Prospective wind energy development in EU Member States from 2010 to 2020 according to EWEA baseline scenario

Increase in wind power capacity by EU member state from end 2010 to 2020 Factor by which wind power capacity will increase and % of the country's electricity demand by 2020		
Austria: x 3.5 (10%)	Belgium: x 4.3 (10%)	Bulgaria: x 8 (18%)
Cyprus: x3.6 (12%)	Czech Republic: x 7.4 (4%)	Demark: x 1.6 (38%)
Estonia: x 3.4 (11%)	Finland: x 9.6 (5%)	France: x 4 (11%)
Germany: x 1.8 (17%)	Greece: x 5.4 (23%)	Hungary: x 3 (4%)
Ireland: x 4.2 (52%)	Italy: x 2.7 (9%)	Latvia: x 6.4 (5%),
Lithuania: x 6.5 (18%)	Luxembourg: x 7.1 (7%)	Malta: *0 to 100 MW* (8%)
Netherlands: x 4.2 (20%)	Poland: x 9.5 (14%)	Portugal: x 1.9 (28%)
Romania: x 6.5 (10%)	Slovakia: x 266 (5%)	Slovenia: *0 to 500 MW* (6%)
Spain, x 1.9 (27%)	Sweden: x 4 (15%)	United Kingdom: x 5 (19%)
EU-27: x 2.7 (16%)		

Source: [EWEA 2011]

In the long term, wind energy could become the backbone of European electricity supply representing the largest single source of electricity in Europe (see chapter 1.1.2).

Table 3: Installed power capacity, electricity production and share of EU electricity demand as estimated by EWEA

	Onshore wind (GW)	Offshore wind (GW)	Total wind energy capacity (GW)	TWh onshore	TWh offshore	TWh total	EU-27 gross electricity consumption	Wind power's share of electricity demand
2020	190	40	230	433	148	581	3,690	15.7%
2030	250	150	400	591	562	1,154	4,051	28.5%
2050	275	460	735	699	1,813	2,512	5,000	50%

Source: [EWEA 2011]

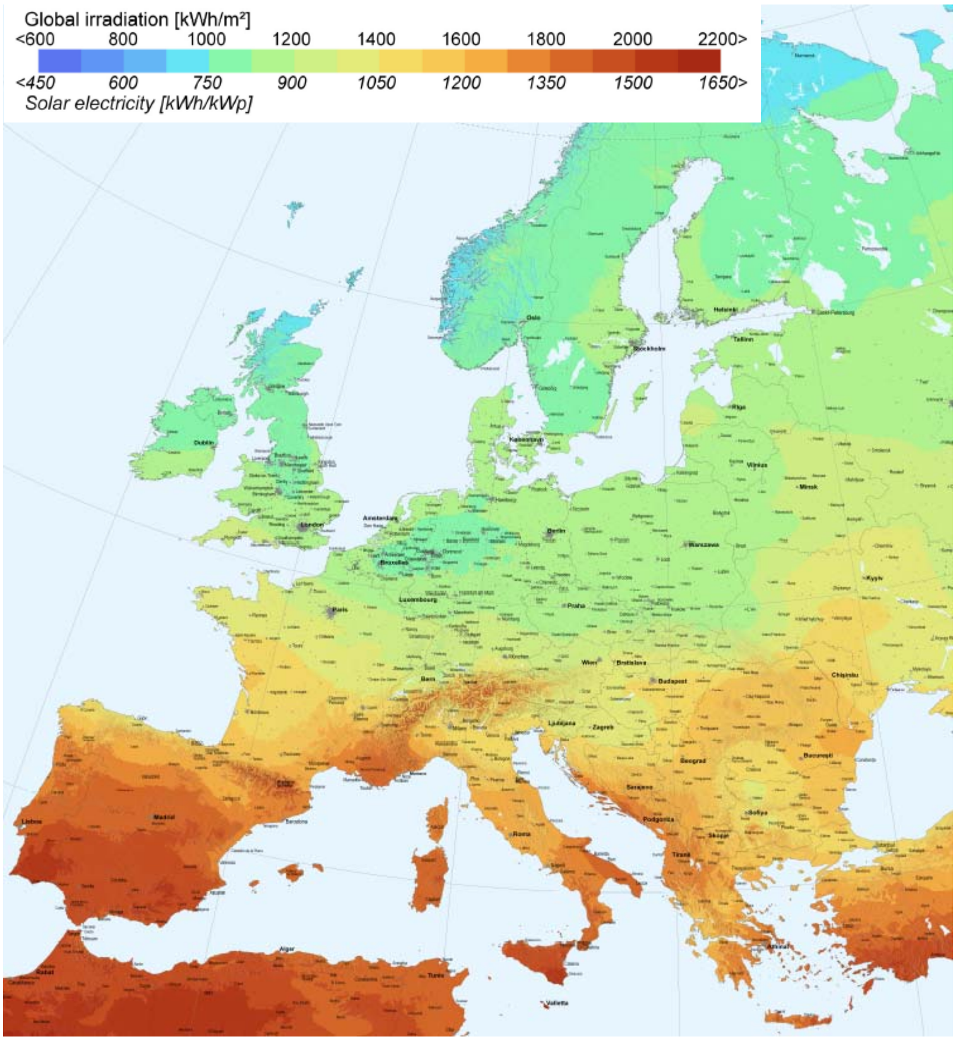
1.3.2. Solar

Map 3 gives an overview of the theoretical solar energy potentials in Europe and the neighbouring countries.

Despite higher annual solar energy yields in the South, it can be expected that **photovoltaics** will be rather evenly spread over the continent, for a number of reasons. Firstly, acceptable sunlight conditions are also available in Northern Europe. Furthermore, the PV supply curve is statistically rather determined (non-availability during nights; high certainty during the day), as well as quite complementary to the wind supply curve (when the weather is windy, it's likely less sunny, and vice versa). In addition, PV supply coincides with midday peak power demands, notably during the summer season when sunshine is driving power demand for air conditioning. Finally, the wide range of PV plant capacities allows for a similar wide range of investors to partake in their deployment: from private ones, citizen co-ops and communities, to institutional ones.

Concentrated solar power (thermal as well as photovoltaics based) is clearly confined to the Southern areas with high shares of direct solar irradiation. Namely, this is the EUMENA region comprising Southern Europe, the Middle East, and the North African countries bordering the Mediterranean Sea.

Map 3: Global irradiation and PV electricity potential in Europe

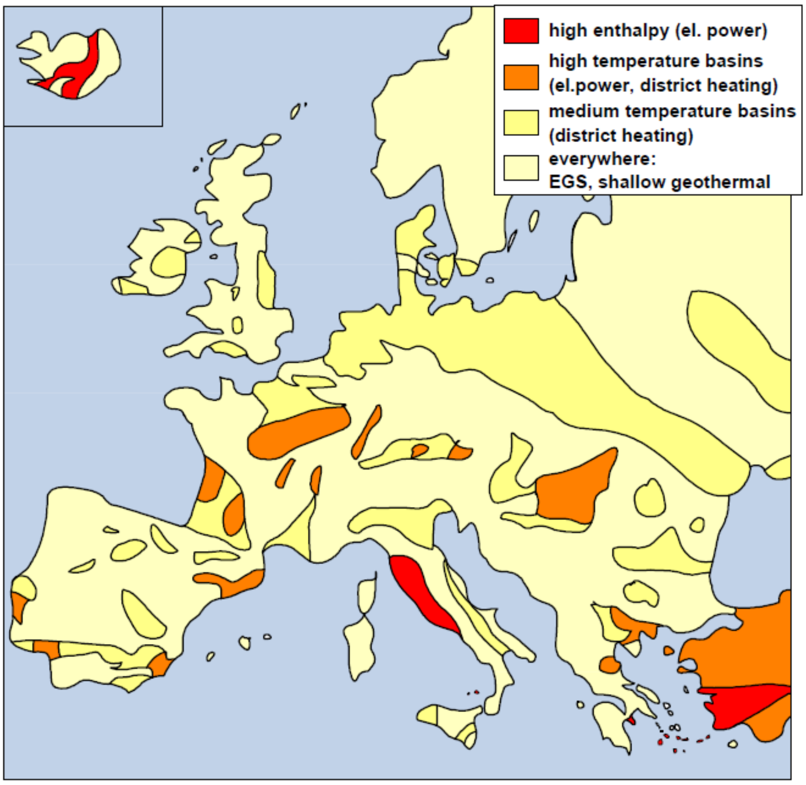


Source: [PVGIS 2011]

1.3.3. Geothermal power

Geothermal energy is heat that originates from the Earth's inner core as well as from radioactive decay in the Earth's crust. Because of the temperature difference between the underground and the surface (geothermal gradient), the heat flows towards the Earth's surface; in the European continental crust this happens at a rate of 26-140 mW/m² [Badino 2005]. **Geothermal energy** is thus available everywhere in Europe, although with significantly different underground temperature profiles. Map 4 gives an overview of the different geothermal resources and possible uses of this energy in Europe.

Map 4: Main basins and geothermal resources in Europe including potential uses



Source: [Antics 2007]

Low temperature heat is available practically everywhere. Within a few (tens of) metres below the ground, there is a steady temperature of some 12-15°C year round, which can be utilised to heat and cool buildings, usually in combination with an electrically driven heat pump to allow for higher and lower temperatures, respectively.

However, **electricity production** from geothermal sources requires a **high temperature heat** of 100°C and above. With underground temperatures increasing less than +1°C per 10 m in preferential geological formations, drilling between many hundreds of metres up to a few kilometres is needed to achieve the temperature levels sufficient for electricity production. The higher the temperature and the more productive the source is (water flow rate), the more efficient and economical is the overall electricity generation process. Thus, **only selected areas in Central and Southern Europe are suited for geothermal power generation, especially in Italy** and Turkey (see the red and orange coloured areas in Map 4).

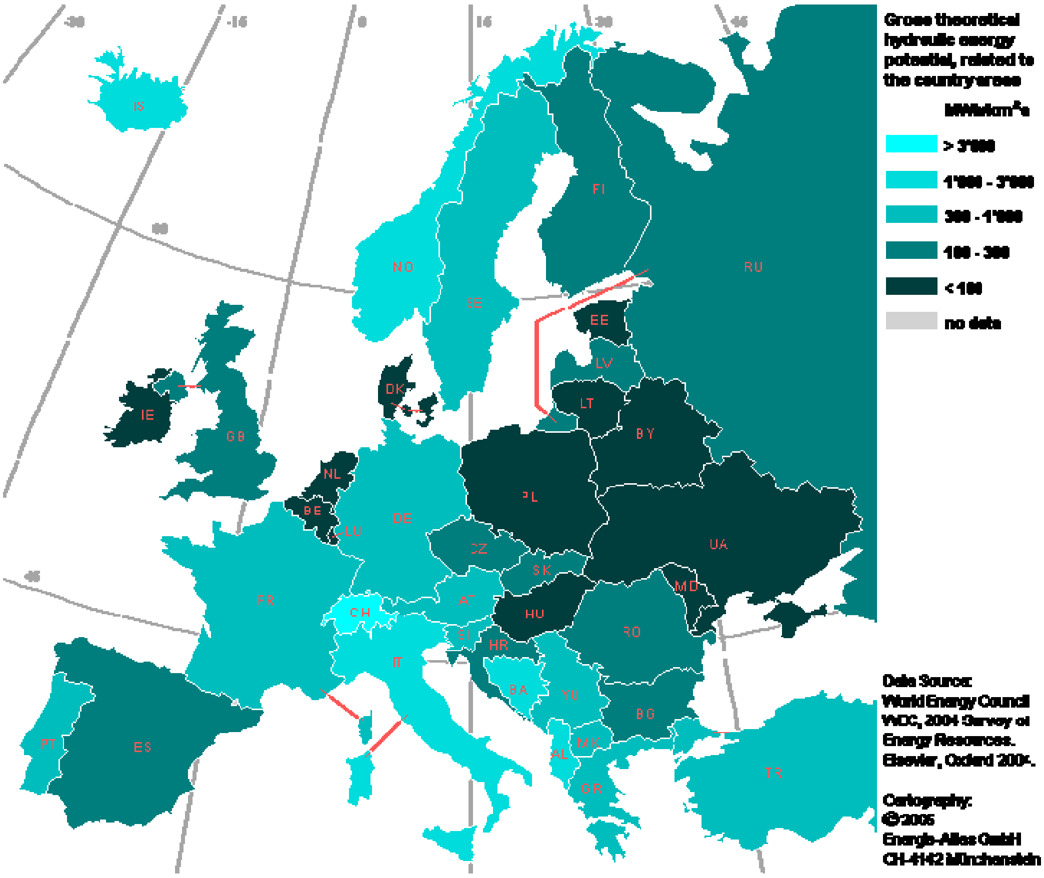
1.3.4. Hydro power

Hydro power makes use of rainfall in combination with height differences (reservoir and runoff hydro power) to produce electricity, or serves as electricity storage (pumped hydro storage). While the former kind is a net producer of renewable electricity, the latter is a sort of battery serving grid quality.

Hydro power is the most mature of all renewable electricity production technologies. There is only a limited potential left in Europe for deployment of new hydro power capacities: by **retrofitting** of ageing hydro power plants (e.g. in the case of Rheinfelden in Germany) to increase their efficiency; in **selected locations** (e.g. in Norway, Switzerland and Austria); or for dedicated purposes (e.g. **pumped hydro**).

As potentials have already been exploited to a large extent, new installations come with increasing risks for negative ecological consequences (e.g. from increasing exploitation of **small hydro power** sources).

Map 5: Hydro power potentials in Europe



Source: [GENI 2005]

1.3.5. Regional differences in uptake of renewable sources

Regional differences in the uptake of renewable energies result from the boundary conditions that vary across Europe and over time. The elements facilitating the uptake of renewable energy generation capacities include:

- **Primary energy availability** (prerequisite but alone not sufficient, "pull driver"), e.g. solar, wind, geothermal, hydro energy;
- **Financial support** to bridge the economic gap ("pull"), e.g. feed-in tariff, tradable certificates, investment support, tax incentives;
- Favourable **regulatory framework** ("pull");
- Low **administrative burden** ("pull"), e.g. preferential feed-in from renewable sources;
- Mandatory renewable energy **targets or obligations** ("push driver"), such as portfolio standards or quotas.

The uptake of renewable energies is ultimately the result of investment decisions. To this end, **"pull"** drivers are making investment decisions more attractive for investors (but without obligations to follow), whereas **"push"** drivers demand action through compulsory measures.

In Germany, the **feed-in-tariff (FiT) scheme** started in 2000[14] has proven very successful in deploying a wide portfolio of renewable energy technologies, including wind, PV, bioenergy etc. For PV, Germany has been the most important installation market worldwide over the past decade. Consequently, the German "Erneuerbare Energien Gesetz" (EEG) has become the blueprint for similar FiT schemes in 45 countries throughout the world [REN21 2010].

Among the instruments applied to support the deployment of renewable power plants in Europe, the FiT scheme is the most commonly used (in 21 out of 27 EU Member States). Table 4 gives an overview of FiT and other measures applied, by EU Member State.

Table 4: EU Member States' use of different instruments for renewable electricity

	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	IE	IT	LT	LU	LV	MT	NL	PL	PT	RO	SE	SI	SK	UK
FIT	x	x	x	x	x	x		x	x		x	x	x	x	x	x	x	x	x			x			x	x	x
Premium					x		x	x	x											x					x		
Quota obligation		x													x						x		x	x			x
Investment grants		x		x	x					x		x	x			x	x	x	x								
Tax exemptions		x							x	x		x						x		x	x			x		x	x
Fiscal incentives			x			x		x											x	x	x				x		

Source: [EC 2011, p 10]

In the case of PV – which could be deployed throughout most of Europe – the study [EPIA-Greenpeace 2011] provides an analysis of the correlation between **well designed support programmes** and the fast uptake of installed PV generation capacities (see Map 6).

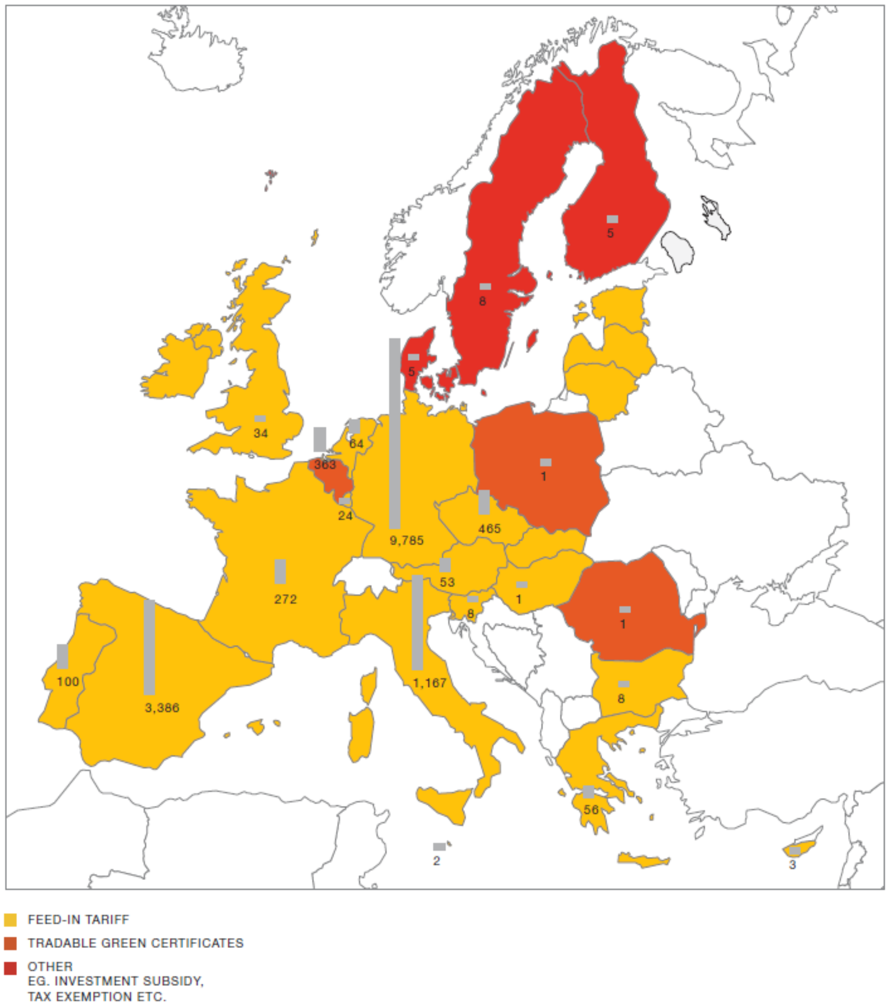
Compared to FiT, **other support instruments** play only a minor role in supporting PV deployment in Europe, both in terms of number of countries and installed PV capacities [EPIA-Greenpeace 2011], [Steinhilber et al. 2011]. Three EU Member States have set-up tradable green certificates[15] and another three are offering an investment subsidy, tax exemption or similar[16], with rather fair results in PV uptake. However, a cost-covering feed-in tariff is an enabler only. What makes FiT particularly effective in some Member States are the accompanying measures, such as **low administrative burden** and **priority access rights to the grid**.

[14] The "German Renewables Energy Sources Act" (EEG) builds on the "Act on the Sale of Electricity from Renewable Sources into the Public Grid" (StromEinspG) established in 1991.

[15] Belgium, Poland, Romania; Belgium is predominantly using a quota system but is offering a feed-in-tariff for PV [Steinhilber et al. 2011].

[16] Denmark, Finland, Sweden.

Map 6: RES support schemes and total installed PV power capacity (in MW_{inst}) by the end of 2009 by EU Member State



Notes: Changes have recently been made to the support schemes in a number of MS. Belgium is predominantly using a quota system but is offering a feed-in-tariff for PV.
Source: [EPIA-Greenpeace 2011, p 51]

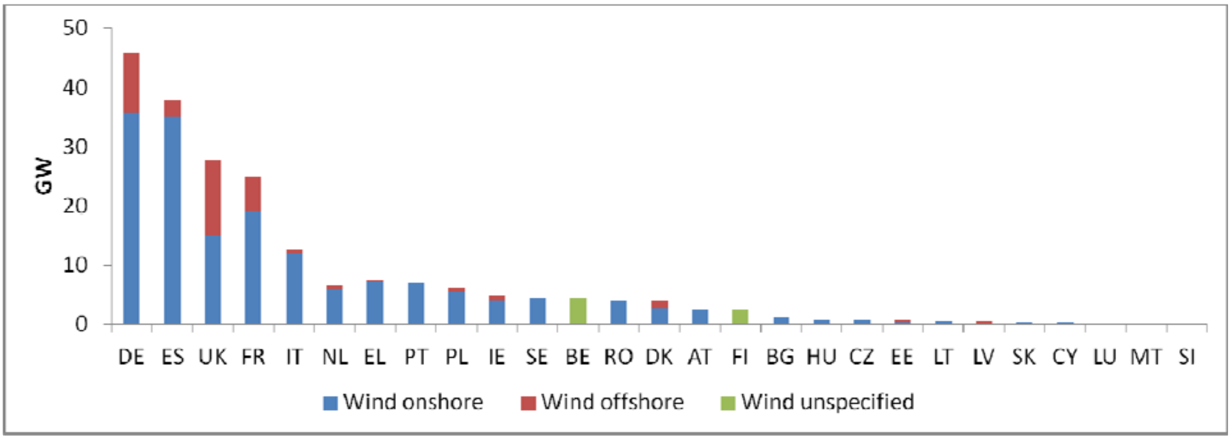
National Renewable Energy Action Plans

In the National Renewable Energy Action Plans (NREAPs), EU Member States have formulated their objectives in terms of installed renewable capacities and renewable electricity generation for 2020. As mentioned above, the total electricity generation assumed in these plans is very similar to that assumed in the EU Energy (R)evolution Scenarios used in this study. However, according to the NREAPs, the contribution of solar energy will be higher and that of wind power lower. The NREAPs are a good means to get an overview of the geographical distribution of installed capacities across Europe, and of the electricity generation to be expected from wind, solar, hydro and geothermal sources for the short to mid-term time horizon.

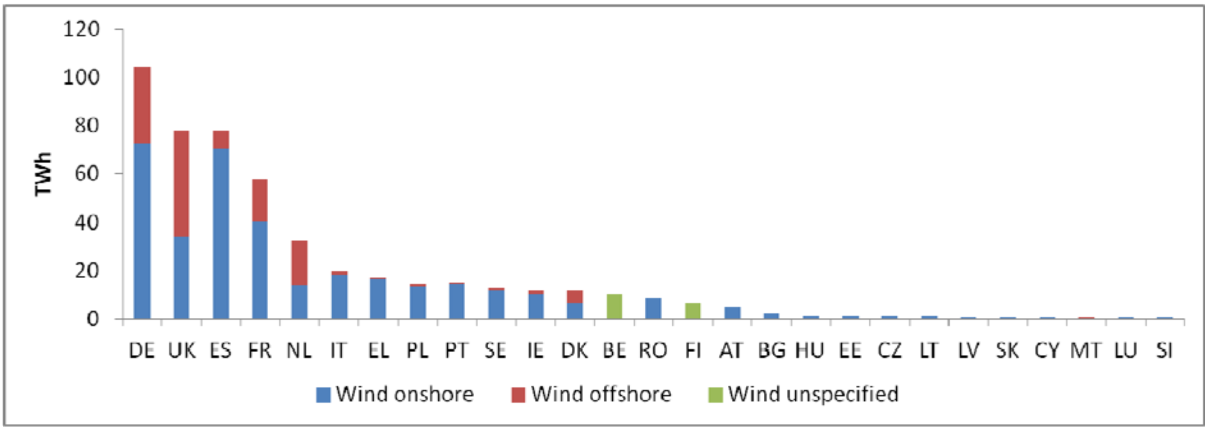
Figure 14 (A)–(I) **ranks the EU countries** according to their planned capacities and electricity generation for the different technologies. Germany plans to install the highest amount of both onshore wind and solar PV capacities. The UK aims at leading offshore wind developments. Spain will install the highest level of concentrated solar power (CSP capacities), while hydro power will be highest in France. Italy plans to lead in geothermal electricity, although at a much lower level than for other technologies. Planned pumped storage hydro power capacities are highest in Germany, followed by France and Spain.

Figure 14: (A)–(I): Geographic distribution of installed capacities and electricity generation for different technologies in 2020 according to the NREAPs

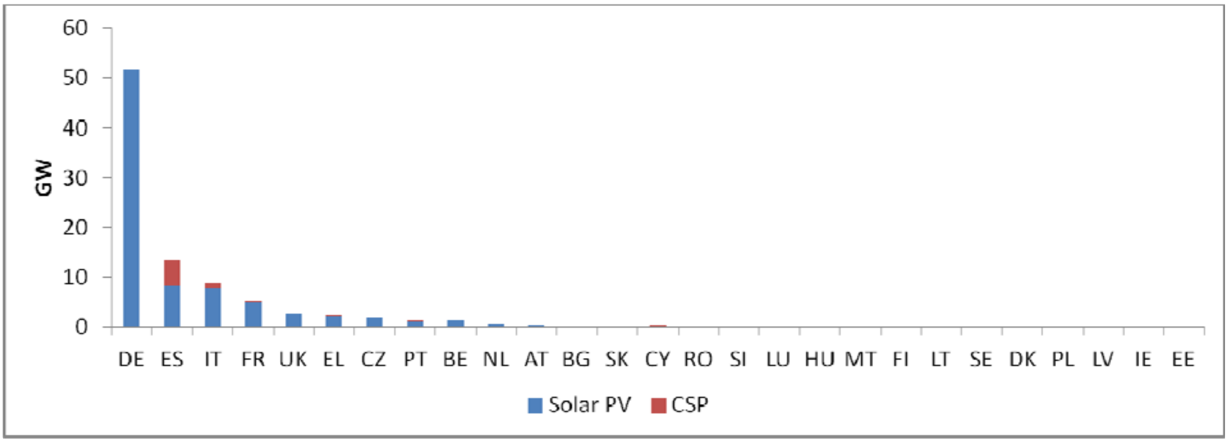
(A) Wind – installed capacity



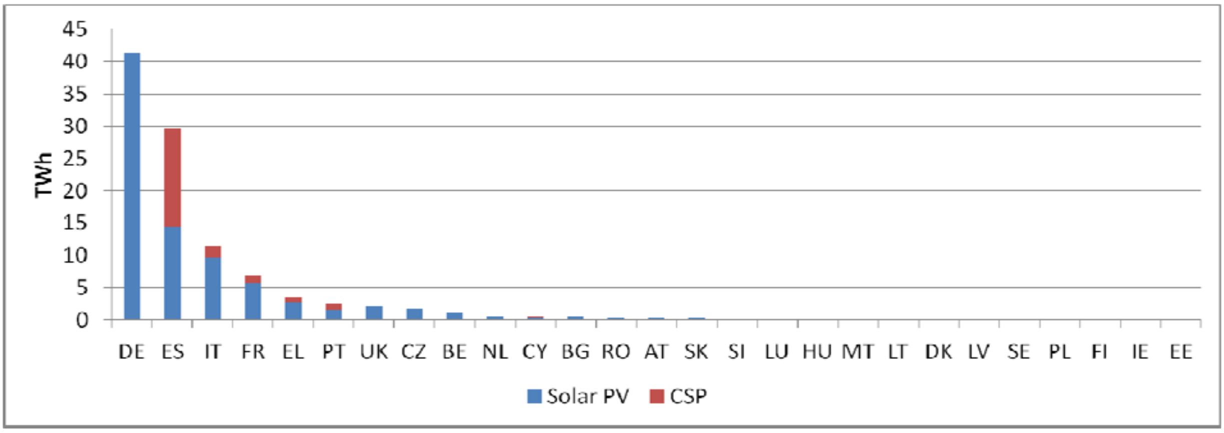
(B) Wind – electricity generation



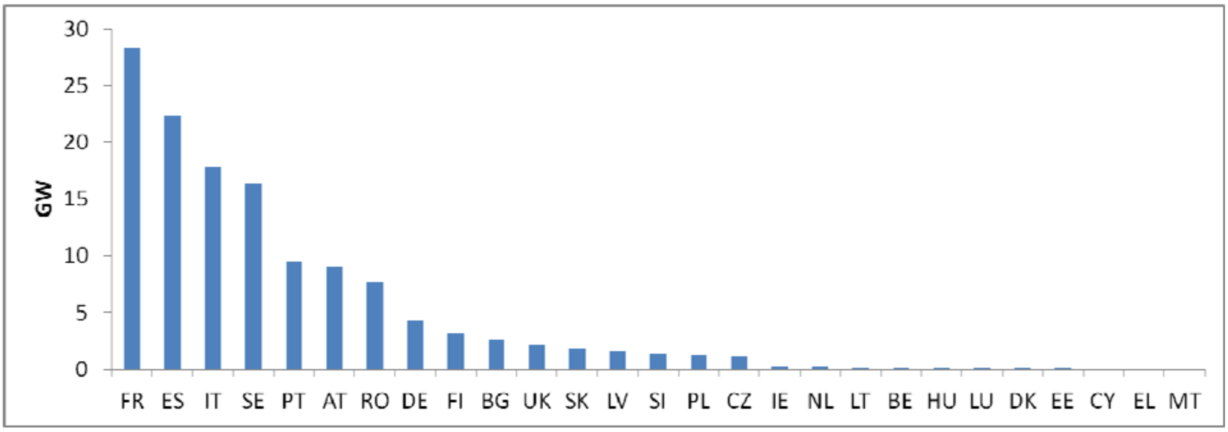
(C) Solar – installed capacity



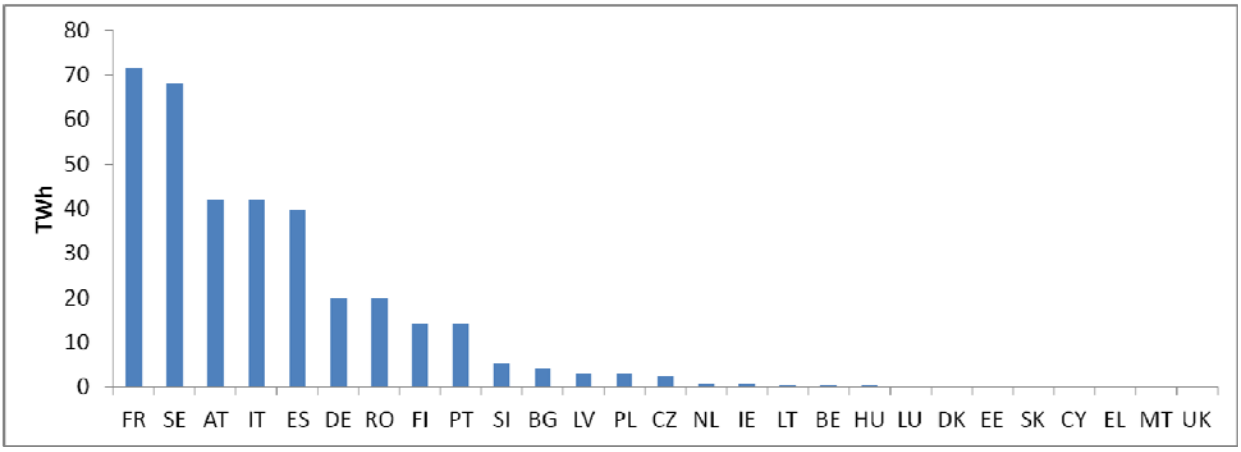
(D) Solar – electricity generation



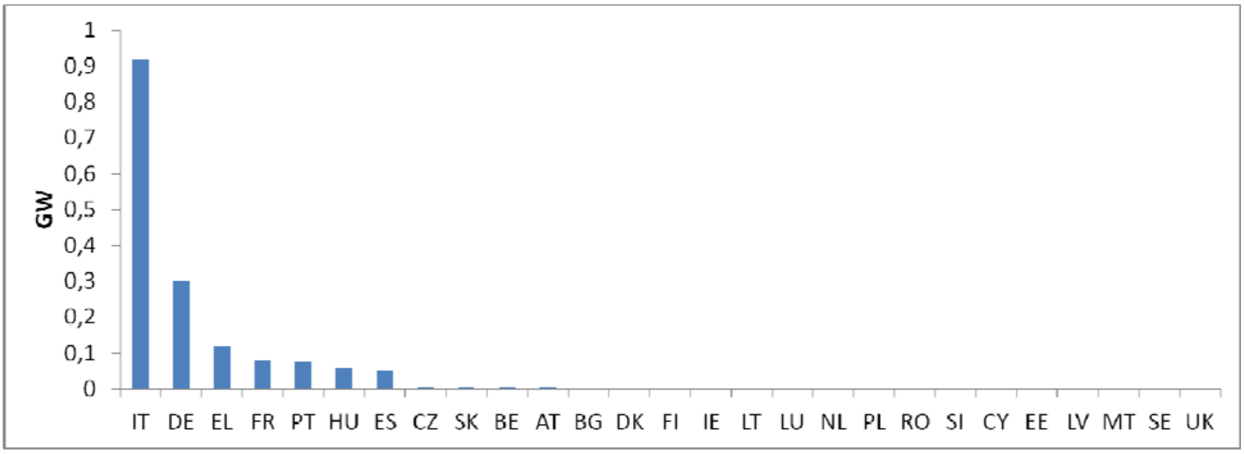
(E) Hydro (pumped hydro excluded) – installed capacity



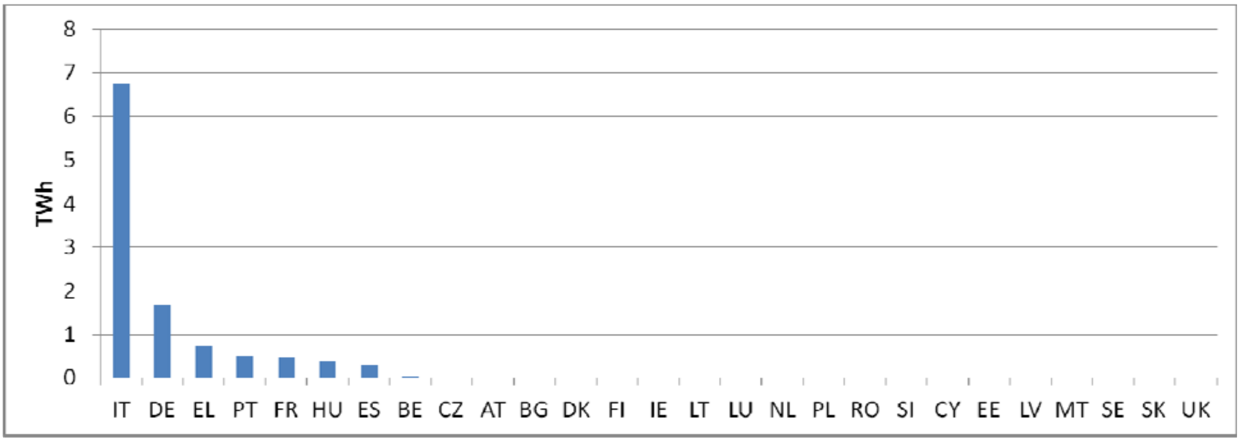
(F) Hydro (pumped hydro excluded) – electricity generation



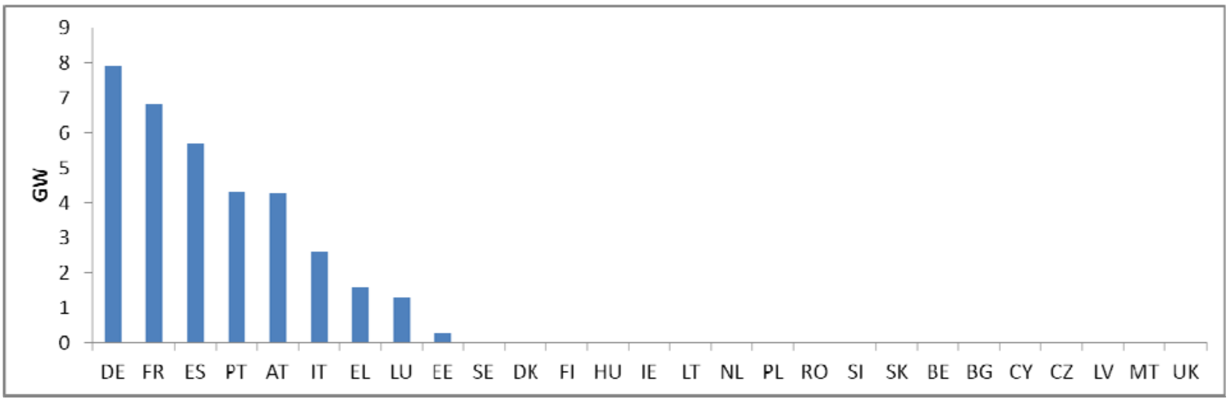
(G) Geothermal – installed capacity



(H) Geothermal – electricity generation



(I) Pumped storage hydro power – installed capacity



Source: [NREAPs by 2020]

Electricity imports/exchange

There is sufficient technical potential for renewable electricity production within the EU27 borders to even exceed current electricity demands [LBST 2010a, Figure 12].

Nevertheless, electricity imports from non-EU countries are an option that stakeholders will regularly reassess with regard to its cost-effectiveness, the potential for supply-diversification etc. **Extending the geographical area for electricity exchange increases the supply security** of fluctuating renewable electricity sources because of local weather and the solar cycle:

- North Africa – Solar resources are an ideal complement to the wind power potentials in Northern Europe;
- Eastern Europe – Including more time-zones flattens the solar supply curve.

The **European Renewable Energy Directive (RED)**, which sets the target of 20% renewable energy in the EU mix by 2020, allows to include renewable energy imported from outside the EU (see chapter 3.4 for an overview of Member States' plans on using Cooperation Mechanisms). However, two limitations have to be kept in mind when considering energy imports:

1. **Exporting countries** first have to serve own demands. Especially the less developed regions still have a great demand potential "to catch up with" in terms of electricity consumption;
2. **Transmission capacities** of electricity lines are lower compared to transport vectors using chemical energy carriers, e.g. pipelines (see Table 5 for a comparison). This may become important in places where the multiple lines are difficult to install due to topographic, regulatory and other reasons.

Table 5: Typical capacities of energy transport vectors

Transport vector	Transport capacity	
	[natural units]	[capacity]
Oil pipeline	1 million barrel/day	73 GW
Natural gas pipeline	33 billion Nm^3/year	38 GW
Hydrogen pipeline (same diameter as natural gas pipeline)	79 billion Nm^3/year	27 GW
Hard coal ship (South Africa ↔ Europe)	4 TWh/year	0,5 GW
High-voltage direct current (HVDC) line	53 TWh/year	6 GW

Source: Translated from [LBST 2010b, p. 154]

Because of the lower energy transport capacities and the losses increasing with transport distance, **imports of electricity from renewable sources can be predominantly expected from countries directly neighbouring EU Member States**, such as Turkey (solar), Russia (wind) and possibly the Mediterranean countries (solar and wind) [EP-ITRE 2011b]. For point-to-point transmission of bulk power over long distances, high-voltage direct current (HVDC) power lines are technology state-of-the-art [EC 2011b], [EP-ITRE 2011], [LBST 2010a].

Case study: Energy from the desert (DESERTEC)

Initiated by the Club of Rome, DESERTEC[17] is a European foundation which works to foster the decade-old vision of using the vast solar and wind energy potentials in the MENA region (Middle East and North Africa) in the framework of an energy partnership with European regions. The DESERTEC Industrial Initiative (Dii)[18] is a consortium of industry and other stakeholders, aiming to make this vision reality. Both initiatives were launched in 2009. The European goal is to have 15% of EU electricity consumption covered by renewable electricity sources including solar thermal power plants, photovoltaics, and wind power from the MENA region by 2050 [DESERTEC 2010]. Transport to Europe is currently considered via HVDC, for which several dozen new HVDC lines crossing the Mediterranean Sea would be required. Alternatively, higher capacity transport vectors – such as hydrogen (H_2) or synthesised methane (e-methane) via pipelines – could also be used, e.g. to supply renewable fuel for transport or backup power plants.

Case study: Mediterranean super grid (MEDGRID)

Launched in 2009 by the French government and set up in July 2010, MEDGRID[19] is a consortium of industry leaders in electricity generation, transmission and distribution as well as in infrastructure financing and climate change services. Its vision is to create new highways for sustainable electricity – through feasibility studies of a transmission network between the north and south rims of the Mediterranean, and of interconnections across the entire Mediterranean region. In November 2011, DESERTEC Industrial Initiative and MEDGRID have signed an agreement to strengthen their co-operation on the development of industrial-scale renewable energy from the deserts and a suitable transmission infrastructure. The two initiatives will coordinate their activities for the long-term generation, transmission and marketability of renewable energy in Europe, Middle East and North Africa.

Case study: North Seas Countries Offshore Grid Initiative

Proposed in 2008 by the European Commission, the UK, Germany, France, Belgium, Netherlands, Luxembourg, Denmark, Sweden and Ireland signed a political declaration in December 2009, launching an initiative to cooperate on the development of offshore wind infrastructure in the North Sea and Irish Seas.

1.3.6. Summary of the European energy landscape

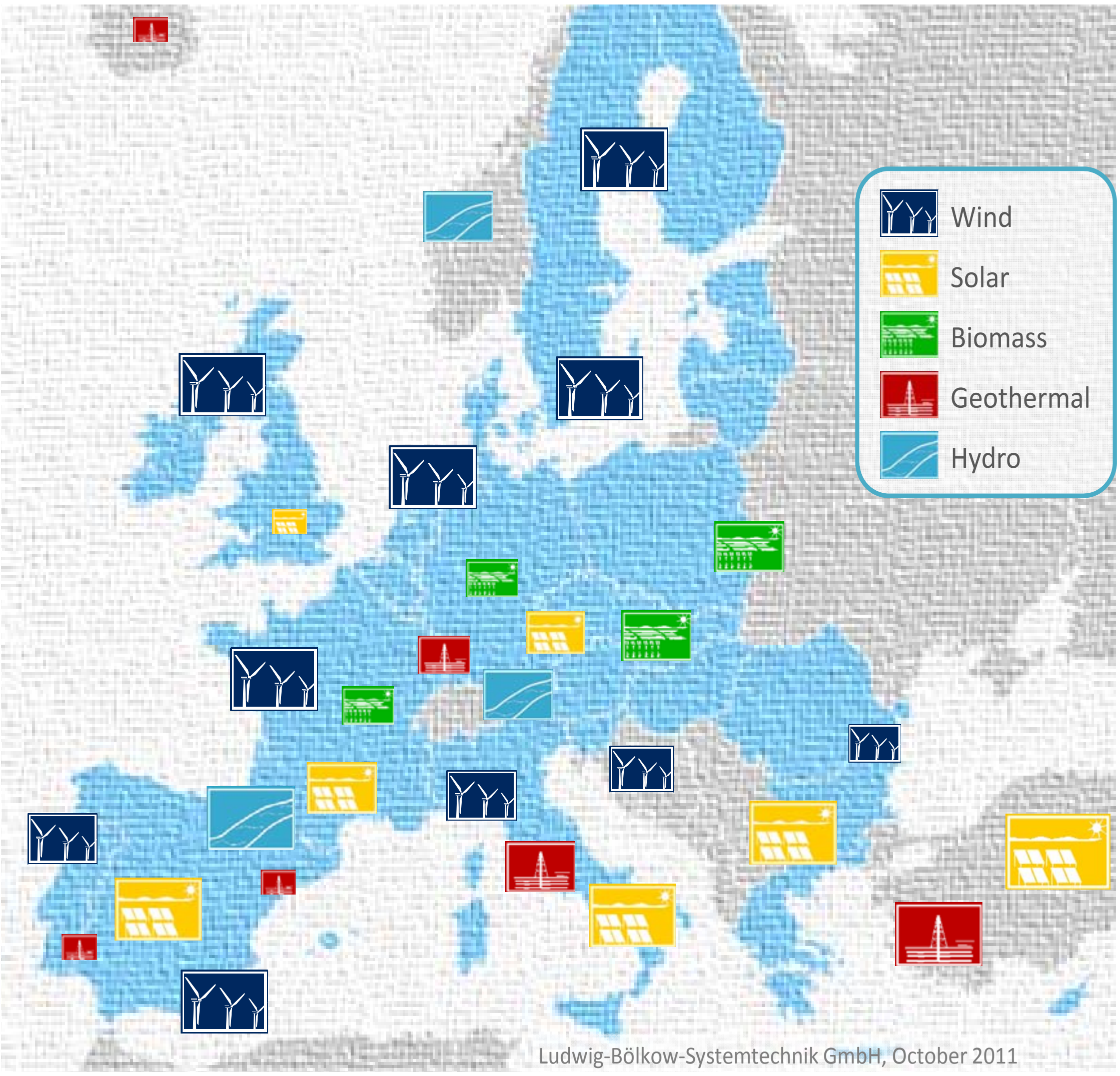
Map 7 gives a summary overview of where in Europe and neighbouring countries the different renewable energy technologies are deployed in the short to medium term (2020+), with a view to renewable energy potentials and the EU Member States' National Renewable Action Plans (NREAPs) reported in 2010.

[17] http://www.desertec.org

[18] http://www.dii-eumena.com

[19] http://www.medgrid-psm.com/en

Map 7: Distribution of renewable power sources in EU27 in 2020 and beyond (indicative scaling and siting)



Source: LBST

2. Infrastructure development needs

KEY FINDINGS

- Drivers for **new interconnections** are the integration of renewable electricity, the integration of the European electricity markets, and the increase of system operation security.
- The electricity system in Europe used to operate top-down, one-way and with plants close to the centres of demand. Renewable electricity is **connected to the grid** at all voltage levels. The average transport distance of electricity supply will increase in the future. Challenges in grid operation need to be solved.
- **Interconnection priorities until 2020** are illustrated in the Ten Year Network Development Plan presented by ENTSO-E. Cross-border projects supporting North-South transfers in Eastern and Western Europe should be prioritised, in order to foster the overall balance between offshore wind productions in the North with solar energy in the South. Interconnection priorities **beyond 2020** will have to be designed according to top-down grid-planning, based on various scenarios of future transmission needs and renewable energy location.
- **Alternative options** to transmission expansion are energy storage, demand response, supply side management, and fuel production, notably for transport. Subject to regional conditions, portfolios with varying shares will be used for reasons of cost-benefit.
- **Energy storage** reduces grid extension needs and increases local energy supply security. There is a broad set of energy storage options available at different development stages. No single energy storage option can cover all energy storage requirements in all European regions alike, i.e. from small to large scales as well as for short, medium and long term energy storage needs.
- **Demand response** of large electricity consumers (including battery-electric vehicles and hydrogen production for fuel cell electric vehicles) facilitates the integration of renewable electricity. Demand response of small energy using products, in high numbers, in private hands have to be carefully assessed regarding cost-benefit, system vulnerability/criticality and data protection.
- **Power-to-gas** production lifts synergies through coupling of different energy using sectors. Both hydrogen and synthesised methane allow for grid balancing through demand response, storage of electricity as a transport fuel, as well as re-electrification of gas to increase energy supply security.
- The results of infrastructure **cost benefit analyses** should guide the selection of the investments to be carried out, and the allocation of their cost. This will be difficult, since the costs and benefits of RES related infrastructure investments are difficult to determine with certainty. The underlying parameters (e.g. fuel prices, cost of transmission investments, and value of system security) are highly uncertain in the long term and their interactions complex. More reliable estimates can be achieved, if the uncertainty is acknowledged and the analysis includes a number of scenarios.
- **Relevant actors** in this process are transmission system operators, distribution system operators, their respective European organisations ENTSO-E and EDSO;

energy regulators as well as ACER. Amid the main stakeholders, renewable energy producers and final consumers will play a key role as well.

- Concerning **financing,** the European Investment Bank is currently the most important source of financing for energy infrastructure projects.
- The **European institutions** will play an ever important role in shaping policies for promoting renewables integration at the European and national levels.
- With a view to renewable electricity integration, proposed **milestones for infrastructure** roll-out and investment up to 2020 are to bring forward the Northern seas offshore grid (UK, Norway, Denmark, Germany, The Netherlands, etc.), the North-South interconnection in Western Europe (UK, Germany, Italy, Iberian Peninsula), South-Eastern European interconnections as well as the Baltic Energy Market Interconnection. Infrastructure reinforcement implies investment volumes in the range of tens of billions of Euros.

This section builds on the previous sections work on renewable energy scenarios, which will be compared with the **existing and planned interconnections**. The section analyses the instances in which the two do not properly match, and reviews the literature on the interconnection priorities for future RES integration in Europe. The aim is to see how well the RES deployment coincides with current and planned grid infrastructure, and how much RES will be concentrated in areas with already congested grids.

The focus of the report is on the **grid implications of renewable electricity deployment** and variable generation in particular. Dispatchable power plants (e.g. biomass) do not increase the need for grid in the same manner.

2.1. Alternatives to transmission expansion

For a high security of electricity supply, it is fundamental to balance the fluctuating renewable power supply with the varying electricity demands **at any time and at any point in the grid**. Top-level indicators to this end are a stable grid frequency (power management) and grid voltage (reactive power management). Options for balancing power supply and demand with increasing RES penetration are discussed in this chapter.

2.1.1. Main options for integrating variable renewables

Power systems have always managed fluctuations and uncertainty in electricity demand. Variable renewables (mainly wind power and solar PV) will increase the existing variability and uncertainty. At low penetration levels the impact is small, but as the penetration gets larger the impact from variable generation will start to overshadow the pre-existing variability and uncertainty [Holttinen et al. 2011a]. Figure 15 shows a schematic picture of **different options** to decrease the integration costs of variable generation. The options covered in this chapter are more specifically:

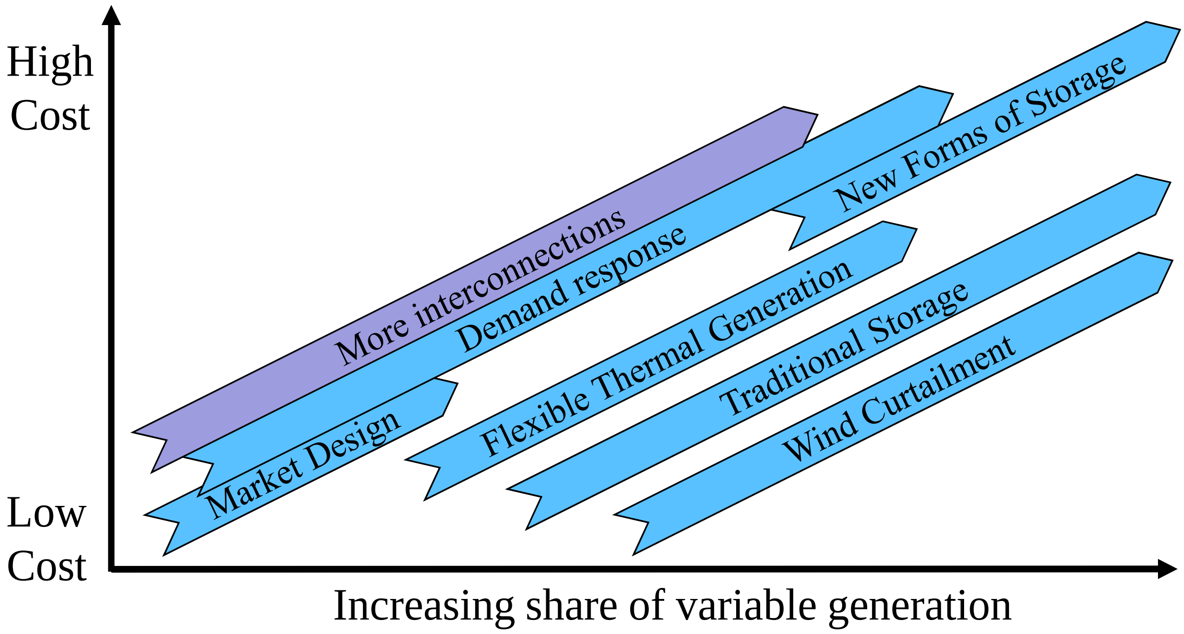
- Increase of (cross-border) transmission lines to smooth variability and enable sharing of resources between the power systems;
- Generation (supply side) management, e.g. dispatchable power sources and even curtailment of variable sources during challenging periods;
- Conversion of electricity into final energy for other uses, e.g. for heating or as a transport fuel (e-mobility, hydrogen, synthesised methane, etc.);
- Flexible demand, e.g. dispatchable charging of e-mobility and other electricity loads;

- Energy storage (pumped hydro storage, batteries, hydrogen, compressed air storage, etc.).

Traditionally, two main methods have been used to cope with the variability in electricity demand. First, **power plants have adjusted their output** to match demand. Second, more **connected power grids** have enabled a more efficient utilization of thermal power plants, while at the same time the overall variability in electricity demand has decreased. Increased variability due to renewables will increase the value of more flexible power plant operation, as well as the value of transmission connections between power systems.

Demand response (DR[20]) and **demand side management** (DSM[21]) programmes have also been implemented before the advent of large scale variable generation. The aim has been to decrease the peak load and to have readily available reserves also from the demand side. Increasing shares of variable generation will increase the benefits from DR, thus making costly programmes more economical to implement.

Figure 15: Conceptual sketch of different options to integrate variable generation (the order of different instruments is system specific and cost increases are not parallel and linear as depicted in the figure)



Note: 'Traditional Storage' refers to reservoir hydro and pumped hydro, while "New Forms of Storage" refers to batteries (stationary and EVs), flywheels, superconducting magnetic energy storage (SMES), Compressed Air Energy Storage (CAES), capacitors and hydrogen storage in e.g. geological caverns.
Source: VTT

Wind power generation from a large area will never produce at full nominal capacity due to variations in synoptic weather systems: the wind will not blow strong enough everywhere at the same time. Furthermore, high wind generation only occurs during relatively few hours of the year (see [Holttinen 2004, p. 33]).

[20] Load responses, e.g. to price signals from the market.

[21] Longer term programmes promoting electricity conservation, especially during peak loads.

If this happens in a phase of low electricity consumption, the **curtailment of wind generation** can be the best option to maintain power system security. As wind penetration increases, curtailment will be enforced more often. This can be mitigated through **increased consumption, new interconnections, or storage**, which would be done during excess electricity generation. Consumption can notably be increased by developing end-uses of electricity that are **flexible in the time-of-use**. A convenient method is to heat water in a hot-water container if there is a later need for heat. A similar approach can be taken for cooling, e.g. by storing ice. About one third of the primary energy consumption is employed for different end-uses of heat and therefore presents a potentially large source of power system flexibility.

Solar PV has a more **pronounced generation profile** than wind. Large scale solar generation will not produce at full nominal capacity even during clear skies at noon, due to dirt accumulation on panels and varying panel orientation. At low penetration levels, PV usually helps the system as it produces during those hours of the day in which electricity demand is highest. At higher levels, however, this turns into a disadvantage as the electricity generation near noon starts to approach the level of electricity demand. Further increases of PV would then require increasing day-time consumption or generation curtailments.

The different options to mitigate the impacts of increased variability and uncertainty are **complementary**:

- More flexible conventional power plants reduce the need for all other measures;
- Demand response and peak-shaving with demand side management reduce the need for energy storage;
- Energy storage near RES generation reduces the need for grid enforcements; both central and distributed energy storage reduce the need for RES generation capacities;
- Upgrading the grid and improving grid operations, e.g. through thermal monitoring of overhead electricity lines, reduces the necessary interventions on the supply side;
- New transmission lines enable the sharing of flexible resources and hence decrease the overall need for them.

2.1.2. Operational practices to integrate variable renewables

Market design and procurement mechanisms for ancillary services affect the operational costs of the power system. Historically, these have been adjusted to serve the operational practices of conventional power plants, some of which are slow to start and benefit from predictable operation. Increasing shares of variable generation will have an impact on the **optimal market and ancillary service structures** as described in the following paragraphs. [Kiviluoma et al. 2011]

Uncertainty can be more economically dealt with if the decisions in power system operations can be made **closer to real time**. This can be achieved with intra-day markets and real-time markets and can lead to tangible cost savings (e.g. [Tuohy et al. 2009]).

Another beneficial change is to change the way reserves are procured. Currently, most reserve categories have fixed reserve targets: however, the range of possible and probable wind power or solar PV output is dependent on the **weather situation**.

For instance, if there is a large high pressure area over the whole region, it is not possible to have high generation from all wind power plants and hence there is no need to keep the same amount of reserves as in a situation in which a weather front is moving over the region and uncertainties are much higher. [Milligan et al. 2010]

The decision of which generation units should be running in order to serve the load and fulfil the reserve requirements is usually based on a **deterministic** view of the future. In **stochastic unit commitment**, the available information about the possible output from variable generation is taken into account. A common method is to optimise the unit commitment decisions with multiple possible future outcomes for demand and variable generation. This can also lead to cost savings [Tuohy et al. 2009].

Sharing of balancing reserves over an interconnection can reduce the total amount of reserves. The cost of providing these will also decrease as more units can operate at their efficient levels. [Milligan and Kirby 2010] review the benefits of larger balancing areas for the integration of variable generation and argue that they are considerable in relation to the probable costs of re-arranging the balancing areas. However, the benefits are highly dependent on the power system and on the chosen attributes for the system. Hence, more accurate **general conclusions cannot be drawn**.

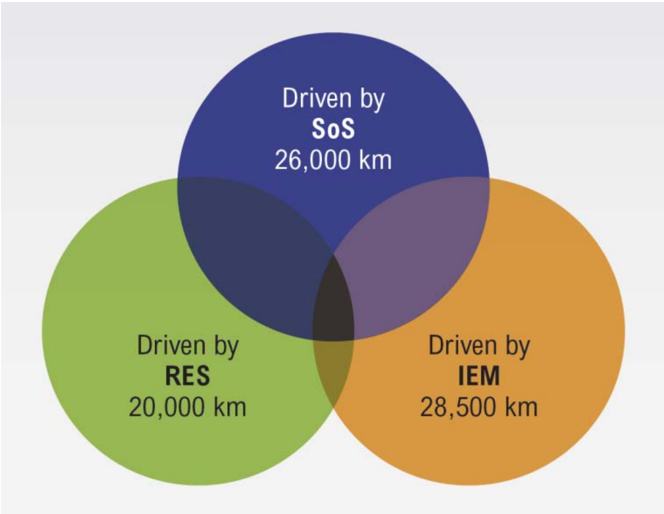
There is still room for improvements in the operation of the existing grid to its maximum transfer capability. For example, in some situations the **dynamic line ratings** based on temperature measurements can increase the maximum allowable power flow through the transmission line by more than 50% [Kim et al. 2011]. Also, **topology adjustments**[22] can increase power flow capabilities [Focken et al. 2009]. Upgrading transformer stations and adding voltage regulation devices (phase-shift transformers, FACTS) can also alleviate congestion situations. **Smart grids** with storage or demand side options can be used to alleviate congestions and curtailments, especially in distribution grids. All these operational measures can alleviate or postpone grid enhancement. However, in a balanced approach grid enhancements will be needed at some stage, depending on the system specific characteristics and technology options preferred by society.

2.2. Drivers for new interconnections

New interconnections provide **multiple benefits**: they will connect and transfer electricity from renewable sources, help manage the increased variability and uncertainty, decrease power system costs by enabling the use of more cost-efficient power plants, and increase power system security. Therefore, it is not often possible to determine unambiguously that a transmission line should be built exclusively to facilitate RES integration. Figure 16 quantifies the relevance of RES integration vis-à-vis two other drivers for grid enhancement, i.e. system operation security and the integration of the European electricity markets. These drivers were discussed in more detail in an earlier work for the ITRE Committee of the European Parliament [Altmann et al. 2011]. This means that during the process of selecting new transmission priorities, all these aspects have to be considered. Some of them can be translated into monetary terms, but sometimes this is exceedingly difficult, for instance when considering the value of security of supply or the value of long term reductions in greenhouse gases and other emissions. With regard to RES impact assessments and cost-benefit analyses, the costs of the deployment of new grid installations cannot be fully attributed to the deployment of renewable power plants.

[22] Power flows can be manipulated through the control of switches and phase-shift transformers.

Figure 16: Main drivers for investment in new or refurbished power lines. There is an overlap between the different drivers and the total line length is less than the sum.



SoS = system operation security
RES = renewable energy sources
IEM = integration of electricity markets
Source: [EWEA 2010] citing the first edition of ENTSO-E's "TYNDP 2010".

2.3. Connecting to the grid

Photovoltaic (PV) systems up to several megawatts are connected to distribution grids (see Figure 11). At low penetration, this will not cause any difficulties, but at higher penetrations PV systems will also be required to play an active role in providing power quality services in the distribution grids. Preferably, the power quality equipment should be installed from the start, so that old equipment will not create unnecessary ("legacy") problems at a later stage. At some point, the PV generation will start to surpass the capacities in transformers and distribution lines. At this point, the cost-efficient continuation needs to be evaluated. Here, a number of options are to be considered:

- limiting PV in congested distribution grids and building elsewhere:
  - large arrays connected to transmission grid;
  - less congested distribution grids;
- upgrading distribution equipment;
- fostering demand response from existing consumption;
- introducing new consumption in distribution grids (e.g. EV batteries or heat/cool storage);
- deploying energy storage.

Smaller wind power plants (i.e. less than 10-20 MW, although this is site and country specific) will be connected to the distribution grid, and larger wind power plants to transmission grids. Wind power is challenged by the cost allocation practices of grid connections.

Many European countries have adopted a so-called **"shallow" approach to grid connection costs**, in which the network operator is responsible for building the line to the wind farm.

The weakness of this approach is that wind power projects will be located only on the basis of the wind resource, without due consideration of grid impacts. This will optimise the wind output but not the use of the existing grid – to install wind power at sites where there is available grid capacity, even if the total available generation is not as high as at other sites.

In a **"deep" connection cost approach**, the wind farm developer is responsible for building the line to the transformer station in the grid, and possibly for the costs beyond the station. This will incentivise building at sites where the grid is strong enough, but can result in a lack of coordination between competing projects and hence in unnecessary line kilometres. It also means challenging transmission planning for the TSO, who will face high uncertainty on where the future projects will be sited.

ERCOT (the TSO in Texas, US) has developed an approach in which **dedicated wind energy zones** are defined on the basis of a top-down analysis of wind energy potential. Based on this, ERCOT has developed a grid extension plan that will be capable of connecting dedicated amounts of wind energy in the different zones [PUCT 2008]. A similar approach is used in some European countries, especially at the regional level, but it could be considered for wider implementation in Europe as well.

Offshore wind capacity that could be built between transmission lines connecting two or more countries has specific problems in the allocation of costs and benefits. During congestion it will also produce to the market with lowest prices. However, the transmission lines will create a net benefit to the system. There are a number of other challenges related to the arrangements to build the offshore grid (North Seas Countries Offshore Grid Initiative), including:

- allocation of costs and benefits between countries;
- different regulatory frameworks in the surrounding countries, including:
  - renewable energy support schemes;
  - regulations on transmission financing;
- technical and operational differences between surrounding power systems;
- investments partially made in anticipation of future developments;
- the potential role of the HVDC multi-terminal technology, which is currently not commercially available.

2.4. Interconnection priorities

The European transmission system has been **built over the last 120 years** by expanding and upgrading the existing grid to meet the new needs. Until as late as 1999 (and 96/92/EC), when the liberalisation of European electricity markets gained momentum, the European power systems have been more or less nationally built and operated. However, there are regions in Europe that are relatively well connected. **Nordic countries** have been connected to tap into the mainly Norwegian and Swedish hydro power resources. Similarly, hydro power in the **Alps** has attracted relatively strong connections from the Alps to surrounding countries. Although there are already relatively good connections to the hydro resources, the increasing share of variable renewables will increase the value of these flexible resources. **Eastern Europe** has a legacy of transmission assets from the Soviet period. While this entails some cross-country connections, for the most part the region is poorly connected by current standards. The disparity in the way current connections are laid out means that some regions will benefit from new connections more than others. Less connected regions are likely to have more price differences, and new connections will increase the operational efficiency of these systems.

The European RES potential is not evenly distributed and a large part of it is located far from consumption. Generation from variable renewables will vary due to weather patterns and solar irradiation, which will create the need for long-distance power flows to transport the generated electricity to consumption centres. Therefore, a European-wide electricity market would be an **important enabler** for the efficient utilization of variable renewable generation. Transmission connections should be optimised to facilitate efficient electricity market operation. This implies both construction of new transmission connections (including the possible adoption of totally new transmission system topologies, e.g. offshore grids) and enhancing operational practices.

In cross-border transmission projects, costs and benefits do not usually line up equally between affected parties. There may even be third parties that receive no tangible benefits but suffer costs (e.g. a transit line across a country). New transmission lines often lead to increasing electricity prices in one country and decreasing prices in another, as the **prices converge**. Hence, transmission lines entail **conflicts of interest**. Still, the integration of power markets and the deployment of the most economic generation sources across Europe by utilizing the transmission grid can yield large **overall cost benefits**. The EU has therefore taken measures to facilitate cross-national transmission planning. In 2009, a network of transmission system operators, ENTSO-E, was founded [EC No 714/2009] to manage the European electricity transmission network and the cross-border trading and supply, to create common Network Codes and to increase transparency. The EU [EC No 713/2009] also ordered the establishment of the Agency for the Cooperation of Energy Regulators (ACER), which monitors and assesses ENTSO-E work and publications.

2.4.1. Current situation and the short-term

Grid expansion needs due to new RES are already seen in Germany, Ireland and Spain, where wind power curtailments happen in critical network congestion moments [Holttinen et al. 2011b]. Germany, UK and Ireland have reported that new grid expansions will be crucial to meet the RES targets [dena I and II, IEAWIND Annual Report 2010 chapters for UK and IR]. In Germany it has also been clearly seen that, even if critical grid reinforcement needs are identified (dena I study in 2005), it is very difficult to actually get these projects implemented. There have been several wind integration studies in some of the EU Member States. These are not referenced in here, as they are a poor guide for European-wide transmission needs. However, many of them have used **methodological rigour not found yet in European-wide studies**. Especially the Irish All Island Grid study [All Island] and its follow-up can serve as a methodological example in addition to the studies performed in the US [EWITS and WWSIS]. Those studies used time-series data specifically developed and combined generation and transmission planning with unit commitment and dispatch modelling. The Irish study also includes detailed grid modelling.

The European wind integration study EWIS was run by TSOs/ENTSO-E. It focused on 2015, and used very similar wind power scenarios as TradeWind (see below). The EWIS study recommended the development of more **coordinated and adjusted pan-European modelling** to assess the future progress of the European transmission network, especially as wind power generation increases. The task of taking the right investment decisions at European level is challenging and will require a significant development programme [EWIS 2010].

The EWIS study included modelling of power flows and dynamic behaviour of power systems. The simulations pointed out substantial loop flows and transit flows in the power system, which might reduce the power system security if not mitigated. [EWIS]

Detailed power flow modelling and dynamic models are **absent from all the studies** (see below) that have assessed the **post-2020 situation**, which increases the uncertainty of the applicability of their results. For example, Net Transfer Capacity (NTC) on cross-border lines may be limited by dynamic stability of the grid, and loop flows reduce the available commercial capacity of cross-border lines.

2.4.2. Priorities until 2020

The EU Renewable Energy Directive [2009/28/EC] sets mandatory targets for renewable energy in EU Member States. EC Regulation No 714/2009 sets the tasks of ENTSO-E including the development of an EU-wide ten-year network development plan (TYNDP). The first pilot plan was published in 2010 [TYNDP 2010] for the years 2010-2020 and ENTSO-E is currently working on the next TYNDP for 2012-2022. ACER monitors the execution of the TYNDP. ERGEG (as predecessor of ACER) provided advice for the TYNDP [ERGEG E10-ENM-22-03] and assessed and commented the pilot TYNDP [ERGEG E10-ENM-22-04].

The TYNDPs provide the current information on the planned and envisaged transmission investment projects "of European significance" (from the TSOs' point of view) in Europe over the following 10 years. The **2010-2020 TYNDP** includes 35,300 km of new power line construction and 6,900 km of existing line refurbishment, corresponding to 14% of the existing network (about 300,000 km) in Europe over the ten-year period. The power line investments of European significance are planned according to three partially overlapping drivers: security of supply, realisation of energy market, and RES integration (Figure 16). A large portion of the **projects** was already **identified** in Decision No 1229/2003/EC and further refined in Decision No 1364/2006/EC.

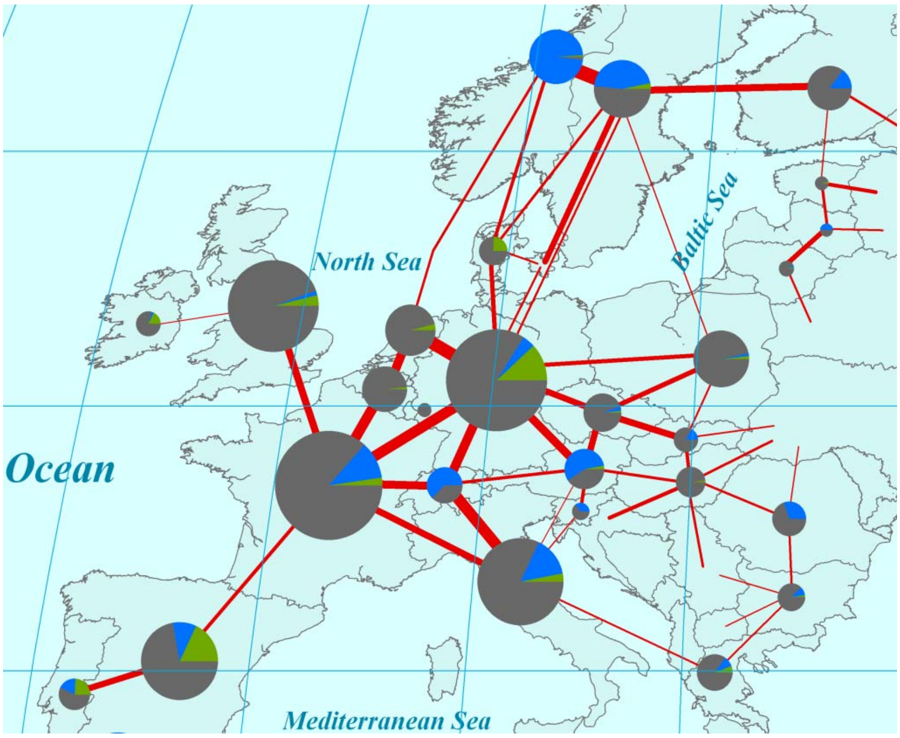
TYNDP acknowledges the existence of two approaches for scenario consideration: the "top-down" and the "bottom-up". The European TSOs have been mostly using the **bottom-up** approach, which defines power system and grid development by tackling upcoming needs as they emerge, and builds on the present situation and transmission system. A **top-down** approach would instead consider the future scenarios and targets, e.g. 2020, 2030, 2050, define the related transmission grid needs, and then apply the trajectory for achieving the target situation. A **shared vision** of European power system should utilise both approaches [ERGEG E10-ENM-22-04].

The **European Commission** [EC 2010a] **criticised** the TYNDP 2010-2020 for not fully accounting for the plans for new offshore wind generation in the North Sea; the need for interconnections in and around the Iberian Peninsula; the need for strengthening the grid in the Central and South Eastern parts of the European grid; and the integration of the Baltic States through interconnections to Poland, Finland and Sweden.

Figure 17 shows the share of variable renewables (wind and PV) as well as hydro power in the total electricity consumption in each country in 2010. Net transfer capacities for the winter 2010/2011 from ENTSO-E have been used to draw the **interconnection capacities** between countries. This can be compared with Figure 18, which shows the same, but with data for variable renewables based on NREAPs for 2020 and the new and upgraded interconnections based on the ENTSO-E TYNDP 2010. New interconnections include those planned to be commissioned by 2020.

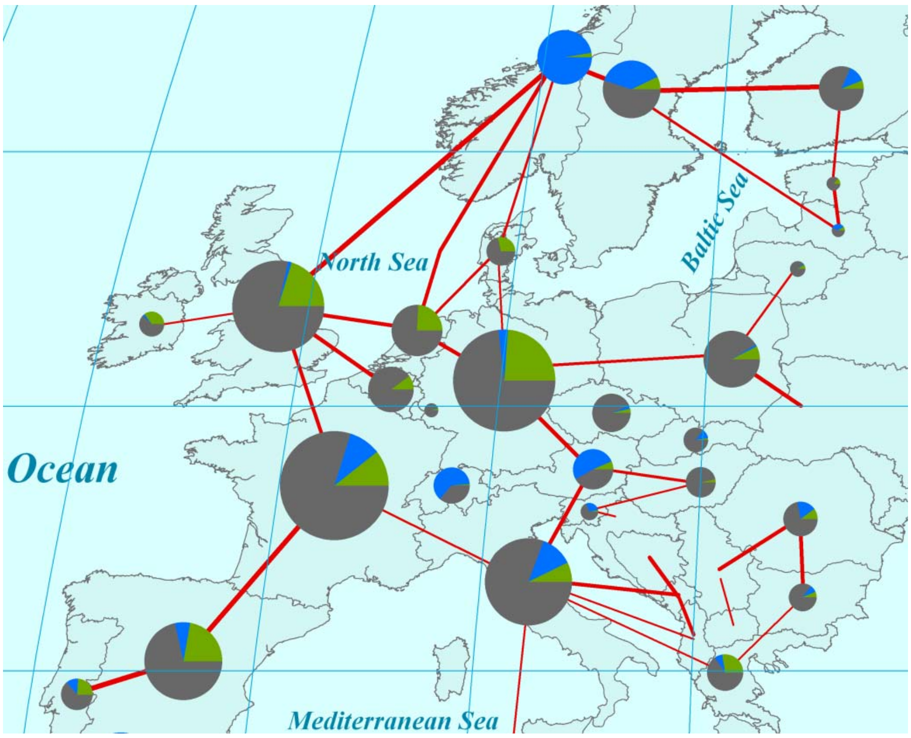
Figure 17 to Figure 19 show that the **major plans for cross-country interconnections** in Europe are from Norway to Central Europe and the UK, as well as in the proximity of the Balkan region. The latter is more driven by conventional transmission needs, although increase in Italian, Romanian, and Greek variable generation is also a factor.

Figure 17: Share of variable renewables (green) and hydro (blue) from electricity consumption 2010



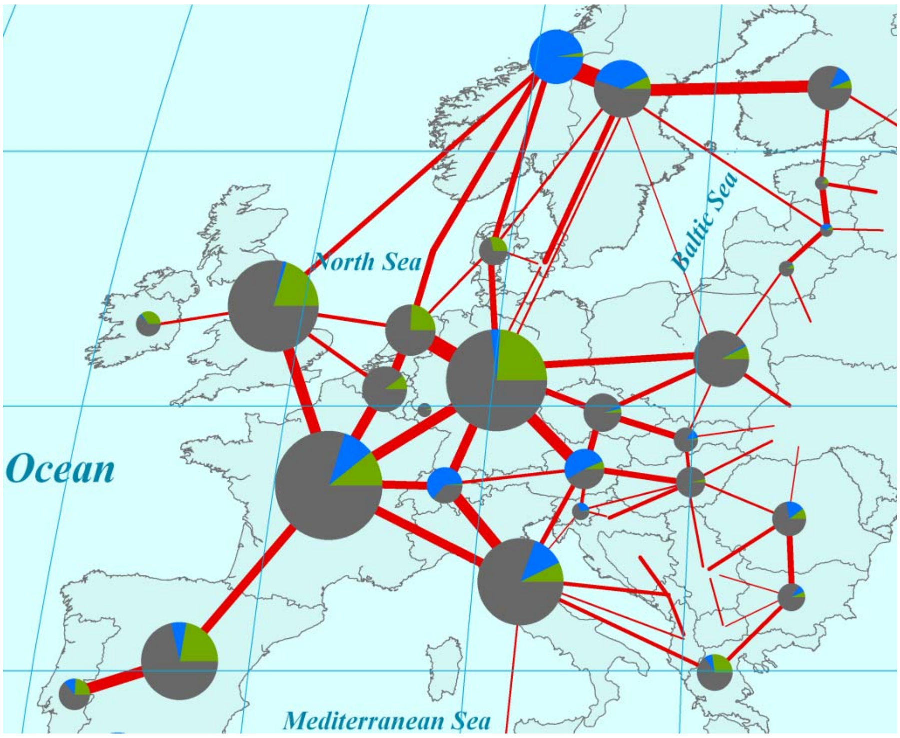
Legend: Red lines are indicative cross-border net transfer capacities according to ENTSO-E values for winter 2010/2011 (average between A → B and B → A)
Source: VTT

Figure 18: Planned interconnection lines between 2010 and 2020 based on ENTSO-E TYNDP 2010



Legend: Red lines are planned lines 2010-2020 based on ENTSO-E TYNDP 2010 (if NTC value has not been indicated, 1000 MW has been used for 380 and 400 kV double circuit lines, and 500 MW for single circuit lines) in addition to the indicative cross-border net transfer capacities according to ENTSO-E values for winter 2010/2011.
Source: VTT

Figure 19: Interconnection lines in 2020 based on existing interconnections and planned lines according to ENTSO-E TYNDP 2010

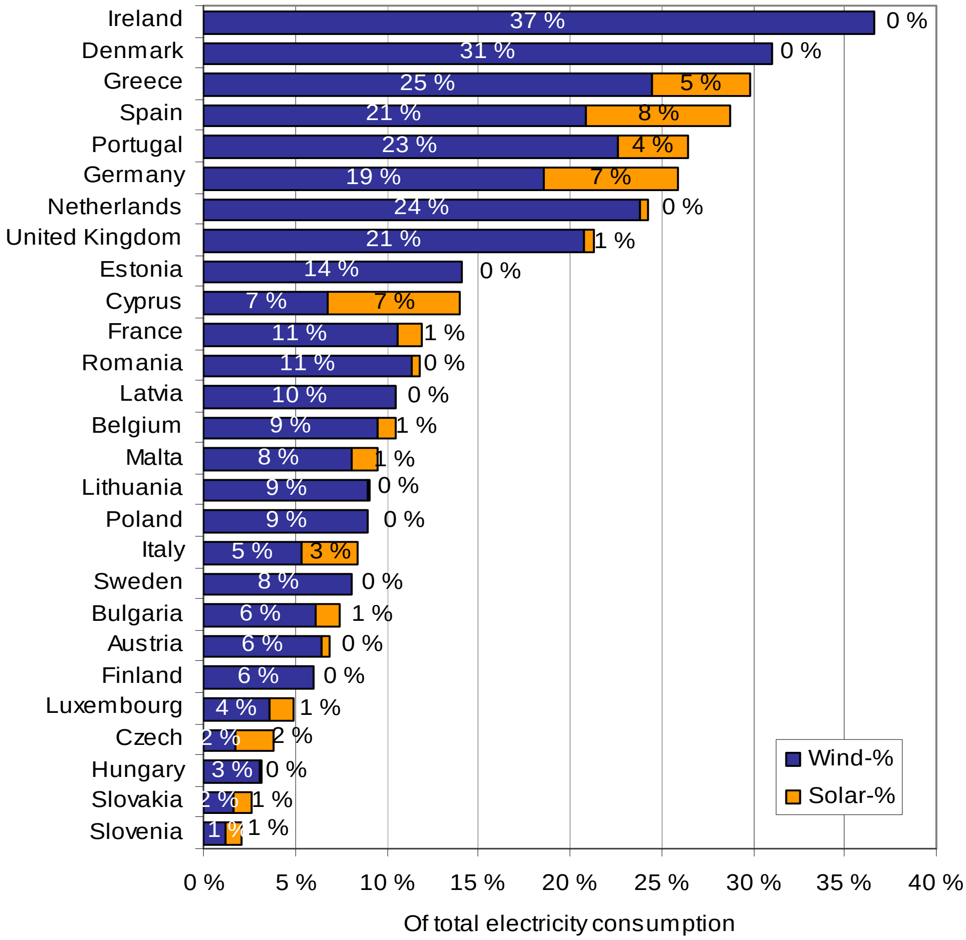


Source: VTT

ENTSO-E TYNDP used generation scenarios that were checked for consistency with the EU 2020 targets. Figure 18 shows that planned cross-border interconnections will mainly increase Central European interconnections to hydro resources (especially Norwegian), add capacity between Portugal, Spain, and France, add connections to the UK, and strengthen the Eastern European grid. These are sensible measures from the variable generation integration point of view, but it is less clear whether they go far enough to be optimal from the welfare maximisation point of view as discussed in chapter 2.6 The approach for the pilot [TYNDP 2010] **did not consider the longer term impact (post-2020)** on what should be built during the next ten years. Furthermore, transmission planning should be done in parallel with energy resource planning, i.e. where the electricity should be produced considering the variation in physical resources.

According to Figure 20, in 2020 Ireland, Denmark, Greece, Spain, Portugal, Germany, the Netherlands and the UK will have the largest penetration levels of variable generation. The **highest challenges** will be in Greece, Ireland, and the Iberian Peninsula, since these are weakly connected to the rest of Europe. For instance, renewables in the Iberian Peninsula are isolated from Central Europe, not just because of the lack of transmission, but also because of French nuclear generation. Increasing interconnections to these regions is also more costly than to e.g. Denmark due to distance and rough ground. The TSOs and regulators in the **regions with the highest ambitions are preparing to meet the targets** by studying and testing the system operation in high penetration situations, and by changing the market rules to promote flexibility in power generation and consumption. These measures are described more closely in 2.1.2.

Figure 20: Share of variable renewables in 2020 based on NREAP data



Source: [Ruska and Kiviluoma 2011]

2.4.3. Priorities beyond 2020

The importance of the **top-down grid planning approach** increases as the time frame is extended beyond 2020 towards 2050. The uncertainties in variable generation investments will increase in terms of location, timeframe, and total amount. One source of uncertainty is related to the geographical distribution of variable generation. The focus may develop towards selecting the cost optimal locations from a European perspective, or locations may continue to depend on political decisions. The practical possibilities for building long-distance bulk transmission from remote generation areas to consumption centres will also play an important role in this regard. Assuming a continued commitment to GHG reductions, competing sources of power generation will have an influence on when and how much will actually be built. CCS, nuclear and biomass all have a highly uncertain future.

A solid approach would require a **high number of scenarios** to cover the probable uncertainty range. These scenarios will then help to find transmission build-up pathways that are robust in multiple different scenarios. The challenge of such an approach is the high computational effort. Analysis of multiple scenarios for the European-wide power system in high enough **spatial and temporal detail** will be challenging by itself, but the analysis should also include **power system stability studies**.

Transmission needs will increase over time as the share of variable renewables increases. If transmission is not planned with a long-term vision, it can lead to **sub-optimal investments**. When considering e.g. only 2020, the optimal strategy could be to build a 400 kV AC line, but when the needs of 2030 are considered as well, the line should be built as higher voltage DC line. [EP-ITRE 2011]

The challenges are severe also in the complementary bottom-up approach. Transmission line/grid construction is a **long process** taking several years (min. 5 years, on average 10, and with several obstacles up to 20 years [TYNDP]), and it is an expensive, long-term investment. Land use and environmental aspects have made line siting a difficult, if not impossible, task in some parts of Europe.

The pilot TYNDP as well as the Modular Development of a pan-European Electricity Highway System (MoDPEHS) by ENTSO-E acknowledge the potential and possibilities of e.g. **offshore grids and super-grids** in the future power system scenarios. Especially these longer term scenarios should be studied and possibly achieved through the top-down procedure. ENTSO-E sees several barriers in making e.g. an integrated and internationally coordinated offshore grid (in line with the challenges listed in chapter 1). Uncertainties increase with the time horizon. The forming of scenarios should therefore be a participatory process, influenced by the possible political decisions (e.g. climate treaties) and the uncertainties in power generation (e.g. [MoDPEHS, p. 27]). ERGEG criticized the low number of scenarios/cases studied in the pilot TYNDP and the same would apply to the future scenarios of MoDPEHS – several technologies, e.g. offshore grids and super-grids, ought to be studied extensively in conjunction with several alternative power production scenarios.

An overview of the most important studies in this area is provided in Annex 1.

2.5. Energy storage, demand response and e-mobility

This section looks at all demand side options available to increase power system flexibility, including electricity storage. Management of the supply side is a characteristic of the generation mix and is not treated here. However, the **flexibility of the generation mix** is a major factor affecting the economic deployment of other options. Power systems with high amounts of reservoir hydro power, for instance, are in a much better position to economically integrate high amounts of variable generation than power systems with inflexible base load units. Curtailment of generation from variable renewables is only used when the other options are not sufficient to ensure the reliable operation of the power system.

Increasing intra-European exchange capacities reduces the variability of power demand, i.e. increases the likelihood that, at any point in time, somewhere in Europe there is a demand for excess renewable energy produced in another region in Europe. Grid issues to this end are discussed in chapter 2.6.

2.5.1. Energy storage

This section provides an overview of the technological status of storage as well as an appreciation of the electricity storage technologies that may play an important role with increasing shares of renewable electricity in the grid. Cost figures for storage technologies are discussed in section 2.6.4.

The role of electricity storage in the system

For stable and high-quality electricity supplies, it is paramount that power supply and demand are balanced at all times. As the share of variable generation increases, it will replace generation that has intrinsic capabilities for energy storage. The decrease of storable energy will create challenges for matching supply and demand.

Today, **energy is bound in chemical compounds**, i.e. fuels like coal, natural gas or nuclear fuels like uranium, which can be stored and transported over time and space until conversion into any desired form of usable energy. However, a large portion of fuel use will successively be replaced by electricity generation from intermittent energy flows such as wind and PV, which have a vast potential in Europe. "Fuel"-type renewable energies are geothermal heat and biomass, which can be converted into electricity. Their potential vis-à-vis today's level of consumption is, however, limited with respect to total availability and geographic distribution (see section 1.3.3 for geothermal energy; for a discussion of EU bioenergy potentials see [LBST 2010a]).

Today, grid quality in the scales of (sub-)seconds is maintained by the **energy intrinsic to the rotation of generator masses** (inertia) in large thermal power plants that are directly coupled to the grid. In the future, with decreasing operating hours and installed capacities of large thermal power plants, the buffer from inertia will also be decreasing. Wind power may be a substitute to some extent, if the appropriate technology is deployed, but the inertial response of wind turbines is more restricted than that of thermal power plants. Flywheels, ultracapacitors, batteries, superconducting magnetic energy storage (SMES) etc. are options for short term energy storage.

There is no single energy storage option to cover all energy storage requirements in all European regions, i.e. from small to large scales as well as for short, medium to long term energy storage, as will be illustrated in the following chapter.

Electricity storage options

Figure 21 shows an overview of the different options for storing electricity. All are mapped according to typical installed power capacities, energy storage capacities and storage times, respectively.

Energy applications aim at storing electricity to decouple the timing of electricity production and consumption. These applications can replace the intrinsic storage capabilities of the fuels described above. Usually, as can be seen in Figure 21 as well, energy storage applications provide discharge durations of several hours or longer.

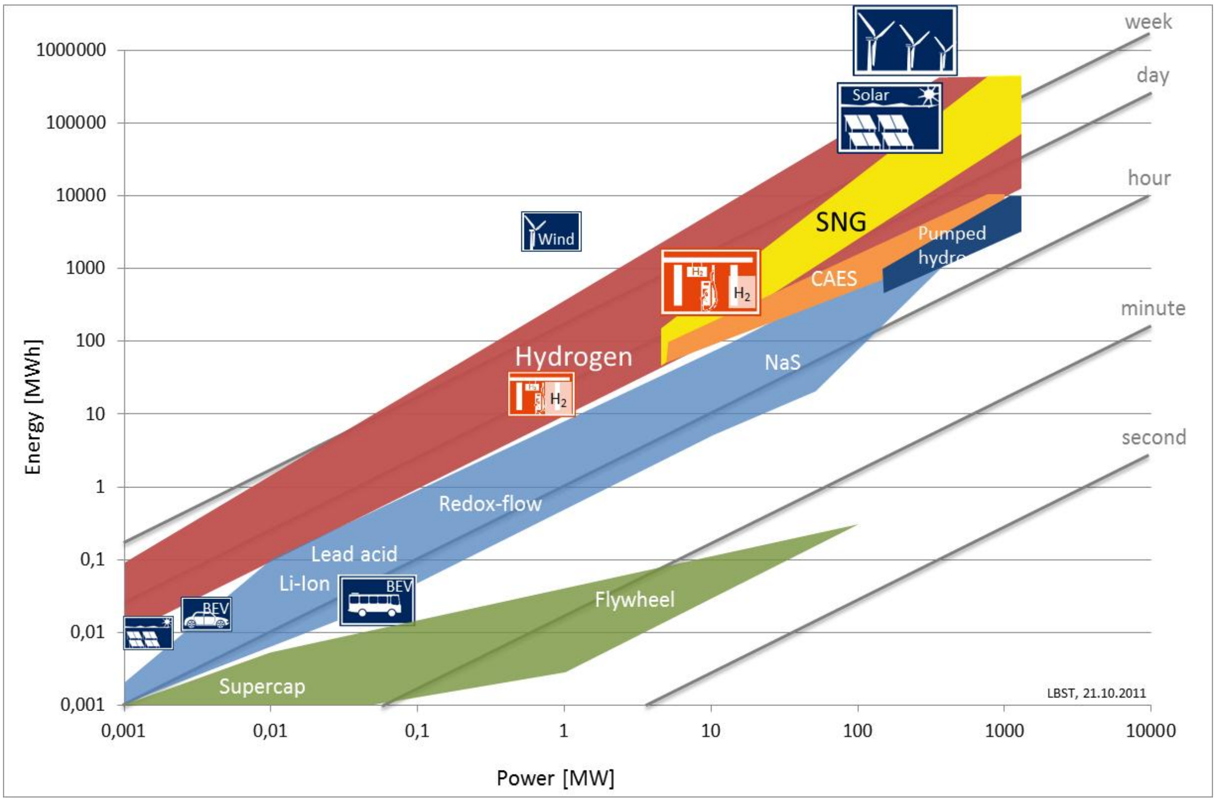
Power applications provide (very) short term storage and are used to ensure continuity, quality, and proper frequency of delivered power in real time. These storage applications normally have a short-duration discharge, varying from seconds to up to fifteen minutes. Pure power applications such as supercaps or flywheels are not further discussed in this study, as this specific characteristic is needed regardless of the degree of grid infrastructure extension and demand side management in the future system.

One needs to distinguish between **storage sizes**. Some applications are used at large scale on a system level; applications on the other end of the spectrum are batteries on household levels. The different uses of storage technologies are indicated in Figure 21. As mentioned above, storage options for small appliances are not included in this discussion; batteries for electric vehicles are assessed in a separate section (see chapter 2.5.3).

In the case of solar thermal power plants (SOT), heat can be stored onsite, e.g. in sand, concrete blocks or molten salt, for the purpose of producing electricity after sunset. This form of storage can provide for load-flattening. **Heat storage** at solar thermal power plants is less flexible compared to pumped hydro or compressed air facilities.

The main current option for energy storage at the system level is **pumped hydro storage**. Other possibilities include **compressed air energy storage (CAES), hydrogen (H_2) and methane (SNG)**. Although all these options provide the potential for bulk power storage, only hydrogen and methane are suited for long term storage, as pumped hydro becomes costly at low utilisation [VDE 2009]. In general, it is often suggested that the different **energy sectors (heat, electricity and transport)** need to become more integrated in order to exploit the synergies with the integration of variable renewable electricity sources.

Figure 21: Mapping of the characteristics of different electricity storage means, renewable electricity sources and demands for transportation



Legend: BEV = Battery-Electric Vehicle; CAES = Compressed Air Energy Storage; H2 = Hydrogen; NaS = Sodium Sulphur battery; SNG = Synthesised Natural Gas.
Source: LBST

A more detailed description of storage technologies with a focus on energy applications can be found in Annex 2.

Case study: Battery system for load-levelling of large-scale PV plant in Germany

A large-scale electricity storage system consisting of stationary lead-acid batteries is planned for peak load-levelling of a freeland PV park. The PV plant with 70 MW_p installed peak supply is already under construction. The rated capacities of the battery system are 50 MW (power) and 20 MWh (energy). The battery system efficiency is expected to be over 85% and the ramp-up to full load will be possible in less than 100 milliseconds. The investment is €23.2 million plus ~€5 million of re-investment after 10 years, whereas the financial depreciation time is 20 years [Belectric 2011].

Electricity storage needs

As described in the introduction to this chapter, grid enforcement, energy storage, demand and supply side management are to some extent interchangeable. The purpose of this sub-chapter is to explore their **interrelations** in order to get an understanding of the room for manoeuvre.

In one of the most comprehensive, but unpublished studies so far, Fraunhofer IWES has analysed the energy storage need for integration of renewable energies [Speckmann 2011]. For this, Europe was split into 70 regions. Electricity supply and demand were modelled for two scenarios with different degrees of grid extension. Assuming optimum reinforcement of the electricity grid, it was found that over 90% of the energy storage requirements can be avoided. Furthermore, assuming also an optimal supply and demand management, the remaining **need for storage capacity is some 20 TWh**, which is equivalent to 2.2 days of average EU power demand in the best case.

Siemens have also analysed energy storage needs with increasing shares of renewables in the grid [Hoffmann 2010]. Assuming a 100% share of renewables, they found that **"shadow power plants[23]" with an installed capacity around 80%** of power demand would be needed for backup if no other measures were considered. Considering energy storage, the amount of energy to be stored is equivalent to 5-20% of the annual energy turnover. Assuming 2.5 equivalent storage full cycles per year, the required storage capacities are **2-8% of the annual energy turnover**. This is equivalent to **an installed storage capacity of approximately 65-260 TWh for Europe**.

Case study: Balancing renewable electricity in Denmark

In Denmark, the penetration of renewable energies (especially wind) is already high, with electricity generation from wind often exceeding current power consumption levels, especially in Western Denmark. For the integration of these high amounts of fluctuating renewable electricity, Denmark is using different approaches [Agersbæk 2010], which are working successfully and may thus serve as best practice for other regions in Europe:

- Denmark is part of the Nordic market that also comprises Finland, Sweden and Norway. Thus, the wind power is balanced in a wider market area. This is facilitated by strong high-voltage DC interconnectors between Denmark and Norway, and between Denmark and Sweden (synergies between wind and hydro power), as well as by integrated electricity markets in the area. The Danish interconnections also allow for a high energy supply security in case of forecast errors and strong weather events [Mansoor 2010].
- Conventional power plants are required to be flexible. For example, coal power plants must be capable to operate at down to 35%-100% of their rated capacity.
- The Danish system features a very high degree of combined heat and power (CHP) generation and district heating. Oversized thermal storage at these decentralised stations allows for a decoupling of power generation from heat consumption (which is an example of integration of different energy sectors). Electric boilers are used for demand side management.
- Wind power provides balancing services.

[23] „Shadow power plants" are dispathcable power plants that are required to guarantee power availability when fluctuating renewables are not producing, e.g. at night or in time of low wind.

In his PhD thesis on the integration of near 100% renewable electricity in 2050 in Germany, Quaschning comes to the conclusion that **some 3% of annual power production** needs to be stored as a best case. The energy storage volumes are comparatively low, as Quaschning assumes demand side management, optimised use of existing pumped hydro power plants, new biomass CHP plants and an optimal balance between installed capacities from wind and solar power sources in order to lower the need for seasonal energy storage [Quaschning 2000]. This assumption is reasonable economically as in general seasonal energy storage is the most costly option (see Figure 15). In the worst case assuming no or limited implementation of the options mentioned above and limited grid extensions, required storage volumes become extremely high beyond any realistic level.

The studies show that electricity storage is required at a minimum level, which is significantly higher than existing pumped hydro storage facilities. There is a need for publicly available, detailed analyses at European level.

2.5.2. Demand response

Demand response (DR) is widely discussed as a promising option to facilitate integration of fluctuating electricity from renewable sources into the grid. DR comprises both the reduction and the increase of the electricity demand of a load upon request, thus providing a source for positive and negative reserve power respectively. The controlling range and ramp times depend on the load's current utilisation and its technical capabilities ("cold" stand-by, "hot" stand-by, part load, nominal load and peak load). The actual execution of the operating range is furthermore subject to the process and control regimes in which the load is embedded.

Demand response is partially achieved by **shifting power/energy demands** from times of high electricity demands (peak) to times of low electricity demands (off-peak). With increasing shares of (fluctuating) renewable energy sources, DR is also suited to shift electricity demand to times when there is an abundance of renewable electricity available.

A decades-long track-record exists for DR:

- **Large electricity consumers** pay separately for power and energy provided. Therefore, industry is planning, monitoring and steering own production processes with the objective to minimise peak power demand, which determines their power capacity price;
- With **small electricity consumers**, e.g. private households, demand side management has been promoted in Europe since the 60s in conjunction with night storage electric heaters. For this, a (uni-directional) ripple control signal is sent from the grid system operator, thus signalling the "off-peak" tariff times to electric heaters and other large electricity loads.

Large scale demand response

As described, the management of power demand in industry was historically mainly driven by industry-internal minimisation of the cost of electricity supply. With a view to increase grid balancing needs in the future, large scale consumers in industry and commerce may provide grid services through demand response.

Refrigerated warehouses are the most commonly cited example with potentially sizable contributions in Europe [van der Sluis 2008]. In fact, any process with intrinsic energy storage – through heat, cold or pressure – could be utilised, provided that the overall process allows for temporary interruptions.

Some experience for integration of large scale DR into 'forward' **capacity markets** exists in the North-West of the USA. For example, Cabot Creamery of Cabot (VT/US) receives 20,000 $/year (55 $/MW per day) for preparedness to curtail 1 MW in demand of its large refrigeration and ice-making machinery upon request [RAP 2011].

Household demand response

In the context of "**smart everything**", not only household demand side management with e.g. heat pumps is discussed, but also household demand response with smaller electricity consuming appliances, e.g. household fridges, washers, dryers, etc. A first step in this direction is smart meters allowing users to monitor their electricity use in real time. The next step would be the implementation of communication interfaces in household appliances and the establishment of an (automated) control regime. The benefit of household DR using appliances in the lower or even below hundred watt range is, however, disputable with respect to:

- the limited potentials of positive/negative balancing when using white goods (per-unit and absolute);
- the cost and power consumption of IT infrastructure vis-à-vis the benefits from electricity savings and shift of demands;
- privacy issues;
- safety and security issues.

While theoretical potential is very high – hundreds of millions of white goods in the EU with a few hundred watt peak electricity demand each – there are practical limitations that result in very limited usable DR potentials to this end: not all goods are equipped with the necessary IT; availability for DR is subject to windows of activity (e.g. need for dishwashing); state-of-operation determines whether positive or negative power can be called-off (e.g. positive reserve power during heating phase of a washing machine), operating constraints (e.g. not all washing machines may run during night time for noise reasons), and so forth.

As an example, [von Roon 2010] has developed a scenario considering these restrictions and calculated the resulting practical potential for positive and negative balancing power through demand response of **household appliances** in the case of Germany in 2020, see Table 6.

Table 6: Practical potential for different household appliances with demand response connectivity (per-unit average)

Reserve power		Dish washer	Clothes washer	Clothes dryer
No of "smart" units in Germany	Year 2020	1.14 million	1.14 million	0.50 million
Day	positive	35.7 W/unit	25.2 W/unit	33.0 W/unit
	negative	-71.5 W/unit	-18.9 W/unit	-24.8 W/unit
Night	positive	5.5 W/unit	3.9 W/unit	5.2 W/unit
	negative	-11.1 W/unit	-2.9 W/unit	-3.8 W/unit

Source: [von Roon 2010, Table 3]

It is noteworthy that DR potentials differ by a factor of 6-7 between day and night time for household appliances. As an example, the DR potential of "smart" dish washers in Germany in 2020 is about 41 MW for positive reserve power[24], and about double this value for negative reserve power during the day. The combined DR potential of all "smart" household appliances in Germany in 2020 is equivalent to around **0.1% of peak demand**.

Thus, household DR has an interesting potential as long as heat pumps and other large consumers are concerned. For smaller appliances, a positive cost benefit ratio is disputable; further analyses are required here.

In addition to demand shifting, **smart meters** as a basic element to the smart grid are also considered to foster **energy saving**. The "human factor" plays a crucial role in realising savings in energy consumption through smart grid elements. According to empirical results from a German demonstration project involving 2,000 households, smart meters, including visualisation of electricity consumption and practical information about energy saving measures, led to an average reduction in electricity consumption of 3.7% [Intellikon 2010]. An average of 9.5% electricity was saved when the former measure was coupled with a **time-of-use tariff scheme**. Further assessments are required to understand whether the reductions observed over several months would remain constant in the longer-term (i.e. whether it would lead to persistent habit transformation), and whether there is a net financial benefit after deduction of hardware and operational costs, and also considering the value of consumers' time. The energy saving potential of smart meters can be generalised to the whole of Germany, while the effect of time-of-use tariffs is statistically weaker, according to the authors who do not discuss whether results can be generalised to the European level.

Critical infrastructure, supply security and the smart grid

Power line, internet and wireless transmission are among the communication options considered for demand response data acquisition and system control. Industry stakeholders estimate that the IT network required for smart grid may be "100 to 1,000 times larger than the internet" (Cisco representative cited in [CNET 2009]).

The increasing **interdependence** of formerly less intertwined sectors through IT systems and networks also increases the **vulnerability of critical infrastructure**[25]. Energy supply is the very basis for our life, as energy is needed for water and food provision. IT has become essential for the functioning of modern societies (administration, process control, etc.), including amenities and gadgets [Fischermann 2011]. What level of interconnectivity is acceptable between energy and IT? In the case of wide-area impacts such as random IT failures, design flaws, cascading effects or targeted attacks, social stability can be at risk [TAB 2011].

Political institutions call for maintaining – or rather improving – the robustness of infrastructures that are vital to the functioning of modern societies, such as the electricity grid [TAB 2011].

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[24] Positive reserve power is load reduction, negative is load increase.

[25] EU Council Directive 2008/114/EC Article 2 (a) defines critical infrastructure as "an asset, system or part thereof which is essential for the maintenance of vital societal functions, health, safety, security, economic or social well-being of people, and the disruption or destruction of which would have a significant impact as a result of the failure to maintain those functions".

However, DSM **operational risks and impacts** increase with the number of smart grid elements deployed (increasing "surface") and with the increasing interdependence of networks (internet, communication, administration, energy, water, etc.). With automated household DSM, this is especially relevant considering the number of units to be deployed (potentially into the billions in Europe alone), and their use outside specialist domains (think of security updates for end user appliances and the problem of legacy products).

On the one hand, there is the issue of vulnerabilities from **unintended failures** (i.e. that are system immanent); on the other hand, there is the issue of vulnerabilities from **intended actions** (e.g. cyber-attacks). Cyber security is a measure to address the latter, mostly discussed in the context of the internet and personal computers. Nevertheless, even so far less affected microcontrollers in process control systems (PCS)[26] have become targets for cyber-attacks. A very early example involving a nuclear power plant dates back to January 2003:

> *« The PCS [process control system] network of First Energy's Davis Besse nuclear power plant in Ohio becomes infected with the SQL Slammer worm. The worm penetrates the PCS network via a call-in connection and infects the system that renders the security parameters. This system is out of use for five hours. The central processing computer is also unusable for six hours. The nuclear plant itself is fortunately undergoing maintenance at the time. »*
> Source: [NICC 2009, p 24]

By 2008, a number of cyber-attack incidents to critical energy infrastructures have been reported:

> *« We have information, from multiple regions outside the United States, of cyber intrusions into utilities, followed by extortion demands. We have information that cyber-attacks have been used to disrupt power equipment in several regions outside the United States. In at least one case, the disruption caused a power outage affecting multiple cities. – CIA Senior Analyst »*
> Source: [INL 2008, p 15]

Another very recent example is that of the Stuxnet malware that was propagated between June 2009 and May 2010. Stuxnet was purposely designed to and probably succeeded in destroying a specific cluster of centrifuges at a uranium enrichment facility in Iran [FhG-SIT 2010], [Markoff 2011].

With a view to balance and manage risks versus opportunities, **cost-benefit analyses** and **vulnerability/criticality assessments** are important steps prior to a broad deployment of smart meters and smart appliances, especially as there are technology options in place with lower system complexity and lower risk of unwanted consequences. These are, for example, "smart" distributed/central electricity storage units (see chapter 2.5.1), e-mobility (see chapter 2.5.3), or user decisions based on e.g. electricity price traffic lights. As the EU Directive on the Internal Market in Electricity [EU 2009] is a major driver for the implementation of smart meters and smart grid elements in the European Union, and because comprehensive and coherent measures are required to adequately manage the associated security and privacy risks as well as standards for interoperability, the **European level** seems to be the appropriate one to coordinate the necessary framework and measures in this respect.

[26] Commonly also referred to as Industrial Control Systems (ICS) or Supervisory Control and Data Acquisition (SCADA) systems.

To facilitate the deployment of the "Smart Grid", the European Commission has established a Smart Grids Task Force[27] and recently put "Actions on data privacy and security of data in Smart Grids" on the political agenda [EC 2011, p 8]. The JRC Security Technology Assessment Unit also addresses this issue in a GRID Coordination Action[28].

Demand response characteristic

In any case, demand response shifts energy demands on an **intra-day** basis, i.e. over hours, not days. Complementary energy supplies such as dispatchable power generation and long term energy storage are needed in conjunction with increasing shares of renewable electricity in the grid, e.g. to provide power at times when sun and wind are not sufficiently available. See chapter 2.5.1 for a discussion of energy storage aspects.

2.5.3. Electric mobility

The possibility of demand response (DR) has been discussed in chapter 0 for industrial processes, commercial facilities and household appliances. The integration of electric vehicles (e-mobility) into DR concepts provides an additional option for the future.

In the case of **battery-electric vehicles (BEVs)**, positive and negative grid balancing can be provided through dispatchability of battery charging. In the long term, the theoretical potential could be hundreds of million vehicles in Europe with a few kW of nominal charging power each. However, not every vehicle/charging socket may be equipped with a control interface for dispatchability (e.g. home charging). Furthermore, BEVs are not connected to the grid all the time. Finally, the actual positive/negative load-levelling potential is subject to the current battery state-of-charge and user choice with regard to vehicle availability. This chain of conditions significantly reduces the theoretical potential for demand response from battery-electric vehicles. Note that negative load-levelling with fast-chargers leads to significantly higher charging losses than with slow-chargers, as fast-charging requires high currents and a doubling of currents leads to a quadrupling of losses.

Vehicle-to-grid (V2G) concepts are being discussed, in which BEVs would actively feed electricity to the grid. This, however, requires additional hardware. Impacts on battery lifetime, consumer warranty and user acceptance are subject to further research.

Business models are currently being explored where BEV batteries are used after the end of their useful life in the car ("2nd life") in **stationary electricity storage applications**, see chapter 2.5.1.

In the case of **hydrogen fuel cell-electric vehicles (FCEVs)**, hydrogen production via water electrolysis can include demand response options. The number of "smart grid" elements involved in demand response is significantly lower, installed power capacities are significantly higher and transaction costs are thus lower compared to BEVs. V2G concept may be an option with FCEVs as well, but requires additional hardware and connection to the electricity grid.

In the long-term and assuming full infrastructure deployment, the number of **hydrogen refuelling stations** is expected to approach 20,000 covering the whole of Europe [Coalition 2010]. Installed per-unit capacities of hydrogen generation plants are in the megawatt range.

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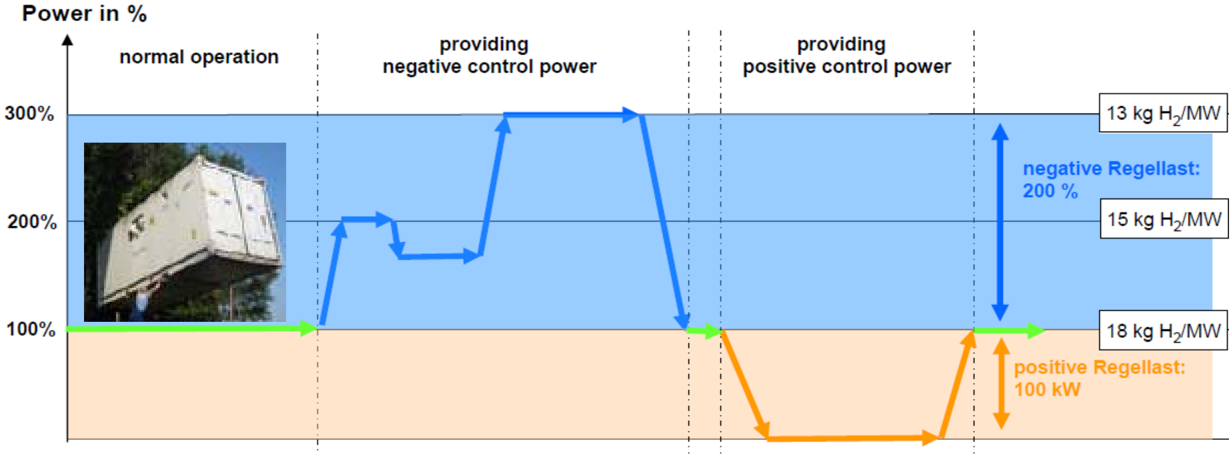
27 http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm

28 http://grid.jrc.it

Figure 22: Example of demand response with a PEM electrolyser for the production of hydrogen



Source: [Waidhas 2011]

Example: Demand response capabilities of hydrogen production

Siemens is developing an electrolyser based on the proton exchange membrane technology (PEM), scheduled to be commercially available in 2012. The system unit is designed to operate at around 90 kW_e or one third of its peak production capacity – thus making use of the higher efficiency of electrolysers in part load – and furthermore allowing for positive reserve power of almost 90 kW_e (down to 3% part load) upon single request. The system is capable of **100% overload** for several hours and up to 200% overload (290 kW_e) for a shorter term [Waidhas 2011], see Figure 22.

Further **characteristics** are a start-up time (black-start[29]) of some 10 minutes; a ramp-up time of less than 10 seconds from standby to full load; and full dynamic behaviour between 0% and 300% of nominal capacity. Direct coupling with variable electricity supply from renewable sources showed **instant load-following** and no degradation [Waidhas 2011].

2.6. Cost benefit analysis of renewable energy grid

2.6.1. Introductory comments

The estimate of both the public and private costs and benefits stemming from investments in RES related energy infrastructure (transmission, storage and devices enabling demand and generation response) is **necessary to assess the advisability of undertaking such reinforcements**. Thus, for example, algorithms employed by system operators to determine the optimal expansion of the grid must implicitly ascertain what the extra costs and benefits resulting from each expansion alternative are. Furthermore, determining which parties will benefit from new infrastructure reinforcements, and to which extent, may be necessary in order to determine who should build and pay for these infrastructures. According to basic economic rationale, the cost of regulated network investments should be allocated to all parties in the system in proportion to the benefits that they are deemed to obtain from the new infrastructures.

[29] According to the SETIS Glossary, the ability to start up independently of a power grid. This is an essential prerequisite for system security, as these plants can be called on during a blackout to re-power the grid.

Network investments entailing externalities for some parties might also require compensation. Allocating the cost of new lines proportionately to benefits (either positive benefits leading to payments, or negative leading to compensation) would warrant that no party opposes the construction of a piece of infrastructure potentially benefiting the system as a whole. Therefore, a satisfactory calculation of the benefits deriving from new infrastructures may be a prerequisite for the construction of many of them.

However, obtaining a reliable estimate of the benefits and costs of infrastructure **poses significant challenges**. First of all, there are benefits of a **non-economic nature**, not suitable to be expressed in monetary terms, which nevertheless significantly affect the value that parties give to a potential reinforcement. Second, most of the economic benefits of energy infrastructure, whose life will span several decades, are subject to **significant uncertainty**. The conditioning factors notably include energy prices as well as spatial and temporal differences among them.

This section opens with a discussion on the main benefits and costs that may result from the construction of new RES related energy infrastructure. Section 2.6.3 aims at identifying those benefits and costs that may be most relevant for each type of infrastructure, with a distinction made between transmission, storage, demand response, electric mobility and supply side management. Section 2.6.4 provides quantitative estimates of the benefits and costs resulting from the reinforcement of different types of infrastructure in Europe, according to the relevant studies published so far. This section also highlights the major deficiencies of those cost-benefit analyses and provides some guidelines on how they should be conducted. Finally, section 2.6.5 provides concluding remarks.

2.6.2. Benefits and costs from renewable energy integration

In this section, we list the main benefits and costs resulting from the construction of energy infrastructures, and the efficient use of the already existing ones, in order to move forward in the integration process of different systems where the penetration level of RES generation is deemed to be high. First, benefits are mentioned. Then, major costs and barriers to the construction of new infrastructures and the integration of power systems are identified. Finally, an in depth discussion of these benefits and costs is provided in Annex 3.

Benefits resulting from the integration of RES-based systems

As highlighted in previous sections, the uneven distribution of primary RES and the non-simultaneity of peak load conditions across a region make **renewable resource sharing** a necessity in order to efficiently meet ambitious targets for the reduction of GHGs and pollutant emissions. In many situations, clean renewable generation that would otherwise remain idle or whose energy production would be wasted could be used to supply loads in faraway areas if the respective systems are sufficiently integrated.

Similarly, **energy storage devices** are required to shift load from times of low variable generation output to times of high output exceeding demand (for instance, wind based electricity production during the night hours). Then, from the point of view of the efficient use of electricity from RES, there is a certain trade-off between electricity transmission and storage. As noted in previous sections, flexible demand and the advanced use of electric vehicles can also contribute to load shifting, thus playing a role that is similar to that of energy storage.

Besides its basic role as enabler of the use of renewable electricity (facilitator of the integration of RES generation), investment in European grid infrastructure leading to a higher level of integration of the national power systems may also trigger additional benefits for the latter.

A list of main benefits associated with the integration of different systems follows:

- Increase in the **efficiency** of the use of RES generation output in a region by shifting RES electricity production or demand across areas in the region and time;
- Reduction of **system operation costs** by allowing the dispatch of modern, more efficient generators in one area instead of older, less efficient units in another;
- **Increase in the level of competition** among power producers by increasing the size of the relevant market;
- Increase in the level of **supply security** thanks to the diversification of the available sources of primary energy;
- Increase in the **robustness** of the resulting market achieved through the sharing of regulation reserves;
- Increase in the level of **demand side participation** due to the increase in the number of potential suppliers;
- Increase in the efficiency of the use of **energy storage** facilities (to store RES energy from other areas);
- Potential increase in the size and efficiency of **new generators** due to the increase in the size of the market.

Costs of the integration of RES-based systems and barriers to overcome

Historically, the vast majority of **national systems** have been designed to be self-sufficient, with relatively weak ties with the other systems in the region, forming e.g. the transnational ENTSO-E network. In most cases, these interconnections (when present) were originally intended solely to enhance system reliability and are clearly insufficient to host future power exchanges driven by economic and environmental needs.

Infrastructure investments required are not likely to be cheap, although it should be taken into account that **energy infrastructure costs are small compared to generation or distribution costs**. Therefore, RES generation expansion plans that are deemed to be necessary (or most efficient) to meet climate policy objectives should not be deterred by associated infrastructure investment costs. These plans may comprise both big central RES power plants and decentralized, distribution level, RES facilities. Most of the challenges faced by these projects are rather of an **institutional or social nature**. Furthermore, the advisability of connecting large amounts of RES generation located outside Europe to the main European grid should be carefully analysed, taking into account the institutional and political risks and the non-negligible network investments that these projects require.

Generally speaking, when deciding on the type of infrastructure best suited to integrate RES generation, the economic costs of the different investments should be weighted together with other types of challenges as well as their potential benefits.

Main costs and barriers faced when pursuing the integration of systems are discussed next. Some of these are economic but the majority are of a socio-political and institutional nature:

- **Costs of reinforcements** to cross-border transmission and storage facilities. Cross-border infrastructure currently in place does not allow efficient electricity trade in the region to take place.
- Political **opposition to** the process of **centralizing** at regional level some of the decisions affecting the functioning of national systems;

- **Lack of coordination of security of supply** policies leading to an inefficient development of the system;
- It becomes necessary to increase the level of cooperation and coordination among countries in the regional market, which leads to **increasing levels of interdependency** among systems. This may be a source of technical problems;
- Increasing **complexity of regulatory mechanisms** to implement expansions of the regional transmission grid, to manage congestion in it, and to allocate its cost to national systems;
- Increase in the level of **technical complexity** of the regional transmission grid: including the possible massive use of relatively new technologies like HVDC;
- Lack of **regulatory harmonisation** among the national systems in the region, which prevents the creation of a level playing field;
- Last but not least, the difficulty to achieve **public support** to the construction **of required network reinforcements**.

When comparing benefits and costs of new reinforcements, one must be aware that the **non-economic ones are notoriously difficult to value**, thus rendering this comparison also challenging.

2.6.3. Specific benefits and costs by the major types of infrastructure

This section separately analyses the case of each infrastructure type, highlighting their major benefits and challenges to overcome.

Transmission

Network investments will ease the existing bottlenecks and connect remote and isolated regions to the energy grid, thus enabling the use of RES energy in areas other than those where it is produced. This should result in a larger and more efficient use of RES electricity generation. Additionally, all those benefits stemming from further integration of the local (national) systems may occur when investing in transmission cross-border facilities (those used by cross-border flows). Fuel costs at regional level should decrease thanks to the larger use of RES generation and the more efficient use of conventional one, taking advantage of the complementarity of the availability of RES energy and peak load timing in the different areas of the region. The level of competition among producers should also increase with the size of the integrated system and the diversity of fuels (and therefore security of supply) that each area of the system has access to. **Regional integration** should result in a decrease of the amount of required regulation reserves; an increase in the level of demand response; a more efficient use of storage; and the installation of larger, more efficient generation units.

On the other hand, moving forward in the integration of systems through transmission expansion will also create a number of challenges related to the higher difficulty to properly regulate the functioning of a larger system in which each subsystem has traditionally enjoyed a high level of independence and applied its own regulatory framework. Regulatory aspects to work on in order to achieve a satisfactory functioning of the regional system include the allocation of competences among local and regional authorities; the procedures for the expansion of the grid, the management of congestion and the allocation of the cost of regional grid reinforcements; the harmonisation of charges and coordination of operation rules; the development of joint security of supply approach; and, last but not least, the social acceptance of new transmission lines, see [Olmos 2006], [Olmos 2011].

Storage

From the point of view of electricity consumption and production, energy storage benefits are somewhat of the same type as those of demand response schemes. In both cases, conventional generation has to face a flatter production schedule resulting in a more efficient operation. This is because storage devices consume power in valley hours and deliver it during peak hours while demand response, among other things, results in a shift of load from peak hours to valley hours. However, there is more certainty on the fact that storage will be used to **arbitrage prices** among hours than on the reaction of consumers to price differences. Besides, storage devices can be used in a likely more reliable way than demand response mechanisms in order to compensate fast and/or unexpected generation deviations (there is more certainty on the reaction of storage to changes in operation conditions than on that of consumers), which is valuable given the intermittent nature of most renewable generation sources. In addition to balancing demand and generation, storage can also be used to provide **black-start capabilities and operation reserves** with time horizons ranging from spinning to long-range. In any case, it must be borne in mind that, as explained in chapter 2.5, there are different storage characteristics not allowing each storage type to serve all storage needs with respect to storage time, capacity, location in the network, responsiveness, etc.

Energy storage investments can also be a **partial substitute for transmission** ones, as load-generation balancing issues can be tackled using both transmission and storage expansion. On the other hand, storage facilities siting is often constrained (e.g. by the need for suitable water reservoirs for pumping or geological underground reservoirs for CAES stations or hydrogen storage), so it may also require greater transmission capacity in order to store energy produced in far-away locations. **Generation flexibility** also partially substitutes for storage.

Most regulatory issues affecting the construction and operation of bulk storage plants seem to be general regulatory issues of generation facilities like, for example, which time differentiation is applied to electricity prices earned by producers and those paid by consumers. However, there are examples of pumped hydro whose construction has been delayed or abandoned because of **environmental concerns** [La Región 2011]. More generally, these technologies might benefit from the **re-design of intra-daily, reserve and balancing markets or mechanisms**, possibly better adapted to massive renewable penetration. For more information on the technical features of storage technologies, see section 2.5.

Different storage technologies may be connected to the grid at different voltage levels and thus face different reference prices (primarily wholesale vs. retail electricity price). For example, batteries at household level might be commercially viable investments when grid parity for solar PV in combination with battery storage is reached, but cheaper technology options exist for large scale/central energy storage where the wholesale price is the reference.

Demand Response

Demand shift from hours with higher net demand (demand net of intermittent generation output) to hours with lower demand should result in a larger use of RES energy. Conventional generation should also be used more efficiently. Besides, both demand shift and peak load shaving should reduce the degree of market power enjoyed by power producers at peak load times. Assuming that **price mechanisms** are in place, allowing consumers to react to extremely high prices caused by the scarcity of energy supply, the level of security of supply should also increase.

Assuming also that load is allowed to participate in balancing markets, maybe in the form of Virtual Power Plants[30], the demand may contribute to the provision of balancing reserves or react to unexpected conditions in the system caused by the existence of an imbalance between available scheduled generation and demand (the result would be the same). This should **reduce conventional reserve needs**.

On the other hand, the massive deployment of the telecommunication and control infrastructure required to implement demand response may represent **non-negligible costs** triggering the opposition of consumers and authorities. Assuming that the implementation of DR measures is socially optimal, the cost of these infrastructures should be allocated to parties (consumers, DSOs, suppliers and service providers) according to their share of the benefits produced. Demand response is in many cases triggered by price signals sent to consumers or service providers. This requires the use of more **advanced electricity pricing schemes** than those currently in place in most systems. Finally, another regulatory aspect to be taken care of is the property and management of **consumption data** of households and enterprises, which may be deemed **confidential, or at least sensitive**, by the latter.

Electric mobility

The electrification of transport would certainly result in a reduction of GHG emissions as long as the electricity powering the vehicles is produced from clean energy sources. Currently, transport accounts for about 23% of total CO_2 emissions in the world, see [IEA 2008]. This provides an idea of the **potential reductions in emissions** that can be achieved by EVs. Given that electricity is cheaper than gasoline as a transport fuel, the partial substitution of the latter with the former could result in a **reduction in overall fuel costs**, though the consumption of transport services may easily increase due to the rebound effect. **Fuel costs in the power sector** would, in any case, increase.

Besides reducing emissions, EVs can be used to **flatten the load curve** in the system if their batteries are charged in a smart way, thus allowing a more efficient exploitation of generation units and potentially reducing RES energy spillages (wind, solar and hydro) by increasing power demand at times when net hydrothermal demand in the system is lowest or even negative. Finally, if provided with **V2G capability**, EVs can act as a form of energy storage, thus leading to the same type of benefits already discussed for other storage devices.

The adoption costs of EVs include those of the reinforcements to be made to the distribution grids in order to allow the charging of vehicles, and those of developing the technology (mainly batteries) to be used in the EVs for them to become cost competitive. While the deployment of EVs is subsidized, society would incur a cost corresponding to the volume of these **subsidies**. Possible obstacles to the deployment of EVs include the adoption of the required technical standards (for plugs and intelligent meters) and the difficulty to develop and implement the business models of the different entities involved in the supply chain.

Hydrogen provides for similar opportunities as battery electric vehicles with respect to the grid integration of renewable energies. It must be noted, however, that hydrogen production has different characteristics as electricity consumption occurs outside the vehicles in stationary installations, which are connected to the grid without interruption.

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30 For more details, see e.g. [Greenpeace and EREC 2010]

This may facilitate demand response and storage capability compared to battery electric vehicles.

Supply Side Management

As stated below, massive renewable penetration modifies the production programme of **conventional generation** so that it generally **is less flat** (a greater difference between the required minimum and maximum production levels), more volatile (a greater speed required to modify the production level) and more uncertain. Therefore, both the capabilities of operating closer to zero production (decreasing the minimum generation level of power plants) and having a faster response (greater production ramps) are at a premium. Among the present conventional technologies, open gas turbine power plants are considered to be the most efficient when producing far away from their nominal rate (the efficiency of CCGTs decreases significantly at low production levels) and abruptly changing their output (they are most **flexible**), followed by other gas-fired power plants. Generally speaking, coal-fired power plants are not so flexible, and nuclear power plants are presently quite inflexible. However, there are large differences between individual plants, and even combined cycle gas plants have been built to be inflexible.

It should be noted that there is a **trade-off between flexibility and energy-conversion efficiency**, so the mentioned inflexibility of traditional power plants partly derives from the desire to maximise efficiency, as flexibility has not been considered such a highly desirable feature in the past. Efficiency is not paramount at a very low utilisation level. Controlling power plants have several hundred equivalent full load hours per year only. New designs and even upgrading of existing facilities could, however, result in greater flexibility, although it is very unlikely that gas-fired power plant levels can be reached. In any case, striking the adequate balance should require that **well-functioning markets for reserve and balancing products** (the "flexibility deliverables") are put in place, in addition to a well-functioning energy market.

Special mention should be made of the procurement of system services by renewable generation. Present regulations in Europe often relieve renewable generation, and in particular wind, from the obligations to provide flexibility services. However, **wind generation** enjoying state-of-the-art control technology **can always provide downward reserves and balancing** and, if operated below maximum output, **also upward ones**. Obviously, the latter case entails a measure of wind spilling, but even so it could be the most efficient operation strategy in a non-negligible number of hours. Similar remarks can be valid for other renewable generation.

In any case, there is also a certain **substitution effect of flexible generation vis-à-vis network expansion**, coming from the economies of scale of operating in a greater system. Obviously, profiting from these opportunities requires the capacity to trade in the flexibility products across boundaries, which in turn possibly requires the adaptation of present regulations.

2.6.4. Quantitative estimates of the benefits and costs of infrastructure

The available estimates of the benefits and costs of infrastructure elements are first provided, and the existing deficiencies in the calculation procedure discussed. Finally, some considerations are included on what a satisfactory computation procedure based on network expansion planning theory should be.

Transmission

Though several studies are available, most of them are partial and difficult to compare to others. Assigning a monetary value to benefits resulting from the construction of transmission projects is difficult, due to the fact that it requires making disputable assumptions. However, in most works available in the literature and providing a quantitative estimate of infrastructure benefits and costs, results are expressed in monetary terms. According to most analyses, building new RES generation and the necessary infrastructure to achieve the full integration of the former is **beneficial for the system** (i.e. the benefits net of costs produced by these projects are positive). Those making a cost-benefit analysis of RES-related infrastructure investments tend to conclude that these also **make economic sense**, though some of these projects may only be profitable in the **medium to long term future**, see the discussion by [FEEM 2011] on the import of CSP based electricity from the North of Africa.

However, many of the works published do not separately discuss the costs and benefits of network reinforcements and of RES generation in the absence of the former, see [EWIS 2010]. Other works provide an estimate of the costs and benefits of network reinforcements but do not distinguish between the reinforcements needed to integrate RES generation and other network reinforcements, see [Winter 2010; Rebours et al. 2010; Czisch and Giebel 2003] among others. Finally, there are other works which have a look at the benefits and costs of network reinforcements that are specific to the connection of RES generation located in an specific area, see [FEEM 2011; De Decker et al. 2011].

Besides, available estimates of **infrastructure costs and benefits** relate to a wide variety of systems. Thus, [EWIS 2010; Winter 2010; Rebours et al. 2010; Czisch and Giebel 2003] focus on the whole European system. Others like [EC 2009; FEEM 2011; De Decker et al. 2011] discuss the connection of large amounts of RES generation in other areas to the main continental grid. Finally, there are others like [ENTSO-E 2010] that analyse specific network reinforcements projects. Time horizons considered (2020, 2025, 2030, 2050) may also **vary widely across analyses**. As a result, the estimates produced by the different studies are, in most cases, **not directly comparable**.

Regarding the **type of benefits** of infrastructure investments considered in these studies, most of them take into account the decrease in fuel costs stemming from the increase in the efficiency of the use of available generation (including RES generation), as well as the decrease in the damage to the environment resulting from a decrease in emissions related to the integration of larger amounts of RES generation. However, few studies consider the decrease in generation investment costs resulting from the avoidance of these investments through the increased exchange flows in the region. An example of the latter is [Rebours et al. 2010]. Benefits to the wider economy, like increases in the overall value of economic activities (GDP) in national systems or the EU as a whole, as well as the creation of (hundreds of thousands) of jobs are only discussed in studies specifically focusing on economy wide analyses like [EC 2010a]. Lastly, very few studies, if any, have managed to quantify benefits related to the increase in security of supply brought about by network reinforcements.

Another **limitation of the existing studies** is that most of them do not include sensitivity analyses to assess the **robustness of results** on benefits and costs with respect to assumptions made when modelling the system functioning. Due to the limitations of published studies, the **benefits and costs figures they provide must be treated with caution**.

Besides benefits and costs related to the operation and expansion of the electricity system, the development of the **regional transmission grid in Europe** will also have an **impact on the economy of EU countries as a whole**. The effect of transmission investments on macroeconomic variables, such as the level of unemployment and the GDP, has also been discussed in the literature. Thus, for example, the European Commission in its *Impact Assessment of the Energy Infrastructure Priorities for 2020 and beyond* states that, if the right **policy and regulatory schemes** were put in place, up to 80% of the total amount of required energy infrastructure investments within the EU could actually take place, leading to an increase of 0.9% in the EU GDP and the creation of about 770,000 extra jobs compared to the BAU scenario, where only 36% of required investments would be carried out (see [EC 2010a]). Infrastructure investment requirements considered in this study had been previously determined in [EC 2010b]. According to [EC 2010a] and [EREC and Greenpeace 2010], the cost of the European supergrid would range between €250 billion and €209 billion[31].

An overview of the most important studies in this area is provided in Annex 4.

Storage

As stated above, storage devices are of many kinds and serve many purposes. They may be mainly intended to store bulk energy and arbitrage hourly price differences (e.g. pumping or compressed air facilities) or to provide different kinds of ancillary services (e.g. flywheels or super capacitors).

However, there is a remarkable **lack of systematic studies** addressing the issue of storage vis-à-vis increased renewable penetration, as well as the impact on flexible generation procurement. The studies found in the literature refer to specific systems, specific time-horizons, specific cost assumptions and deal with specific issues. Therefore, generalisations and comparisons should be done with extreme care.

Stated the above, the literature survey can be summarized in the following points:

- As generation intermittency increases the use of **existing storage facilities** will also significantly increase, as well as their operational profits.
- The economic **case for new investments must be made**, even in the case of technologically mature pumping stations (storage cost in the range 5-10 c€/kWh, highly site specific). There are utility commitments or advanced plans to invest in new pumping capacity. This seems not to be the case for substantial investments in other storage technologies.
- **Other storage technologies** than pumping enjoy levelised costs clearly over 10 c€/kWh, although there are expectations of significant cost reductions during the next 10 to 20 years. In any case, a cost significantly higher than 10 c€/kWh or 1000 €/kW puts this storage technology squarely in or above the range of generation costs. Therefore, it is not surprising that most studies find a limited role for storage other than pumping under purely economic assumptions. Also, and given the small transmission cost relative to that of generation, storage only seems to be profitable when it **substitutes very long transmission lines or transmission expansion is unfeasible**.

[31] Other available studies of the macroeconomic impact of the construction of new infrastructures include [Pfeifenberger and Hou 2011].

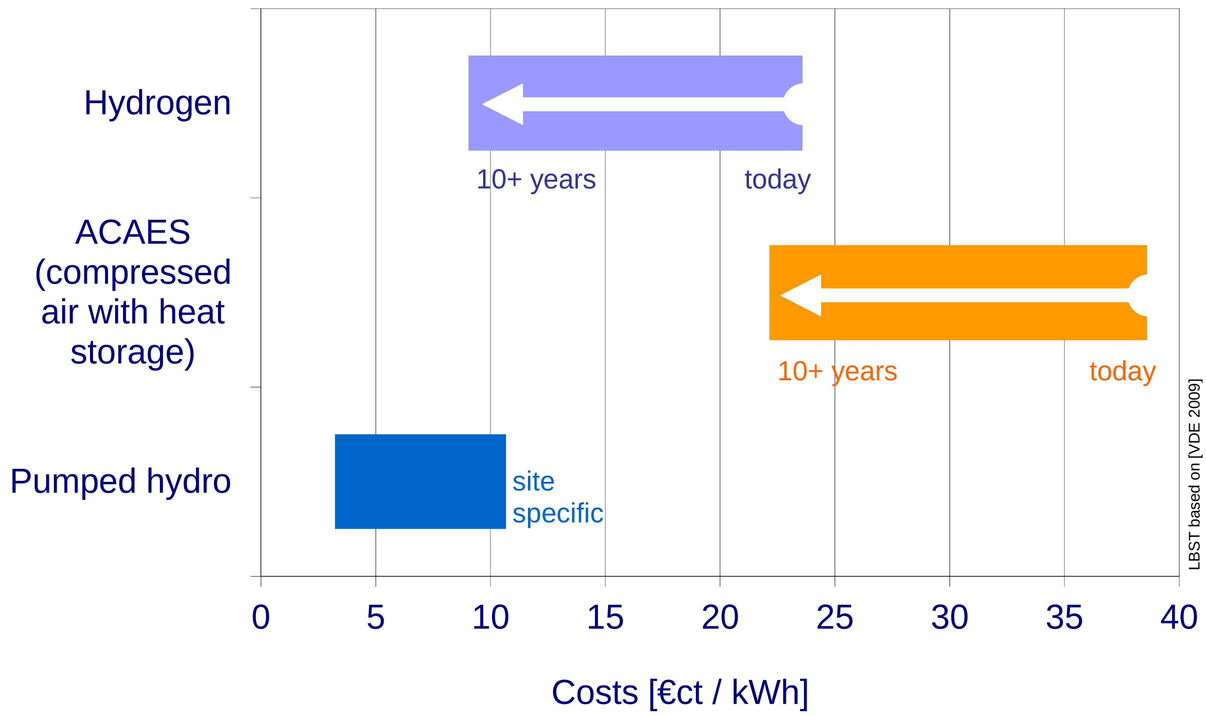
- Storage adds operational flexibility. Consequently, its value strongly depends on the flexibility already present (e.g. whether or not gas turbines are installed). Storage costs in the range 800 to 1200 €/kW result in possibly significant storage penetration. Presumably, if costs fall significantly below 800 €/kW, massive storage penetration would be economically feasible.
- Storage can avoid wind spillage. However, and for the reasons above, it is not clear that avoiding spillage is always the most cost-effective option.

Cost charts in Figure 23 to Figure 25 give an **overview** of the various electricity storage solutions, differentiated by grid level (transmission, distribution) and storage time (short term, long term).

Figure 23 shows an overview of levelised costs for **long term (week) electricity storage** at the high voltage level. Pumped hydro is the most economical; costs of both ACAES and hydrogen (and methane) storage are still high, but have the potential for significant reductions with hydrogen looking more promising. Batteries imply comparatively high costs for storing bulk electricity but are more economical for small scale applications, e.g. with residential PV.

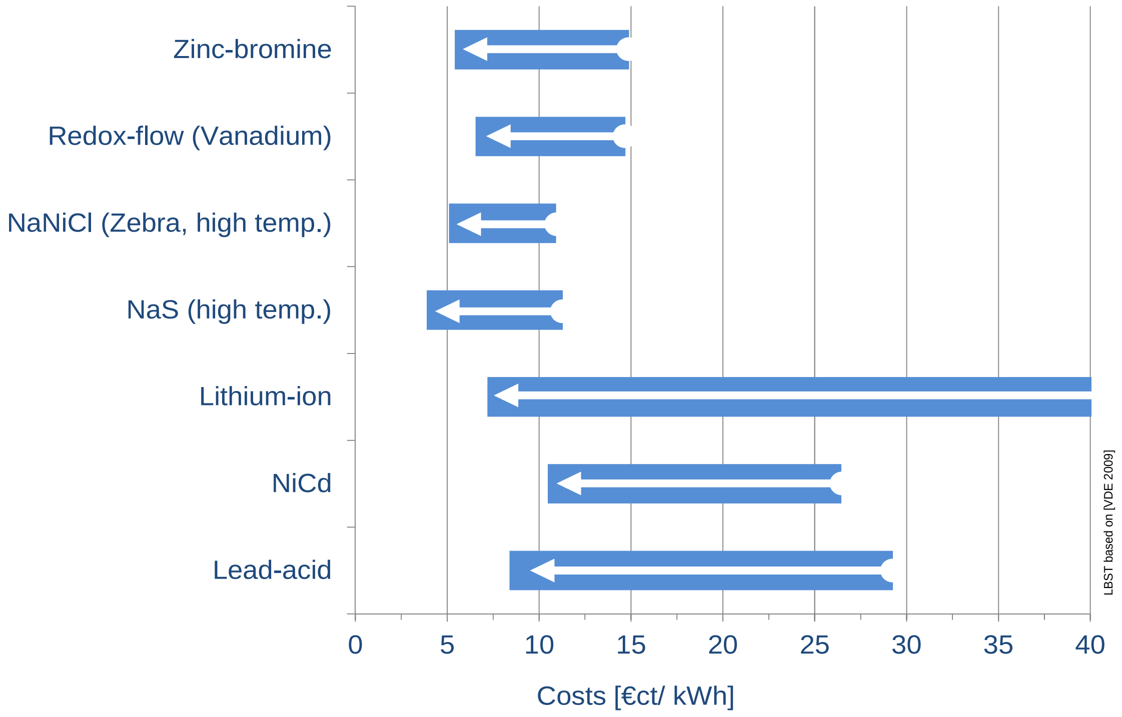
An overview of the most important studies in this area is provided in Annex 4.

Figure 23: Comparison of full costs for storage systems for long term storage ('week storage') in the high-voltage grid



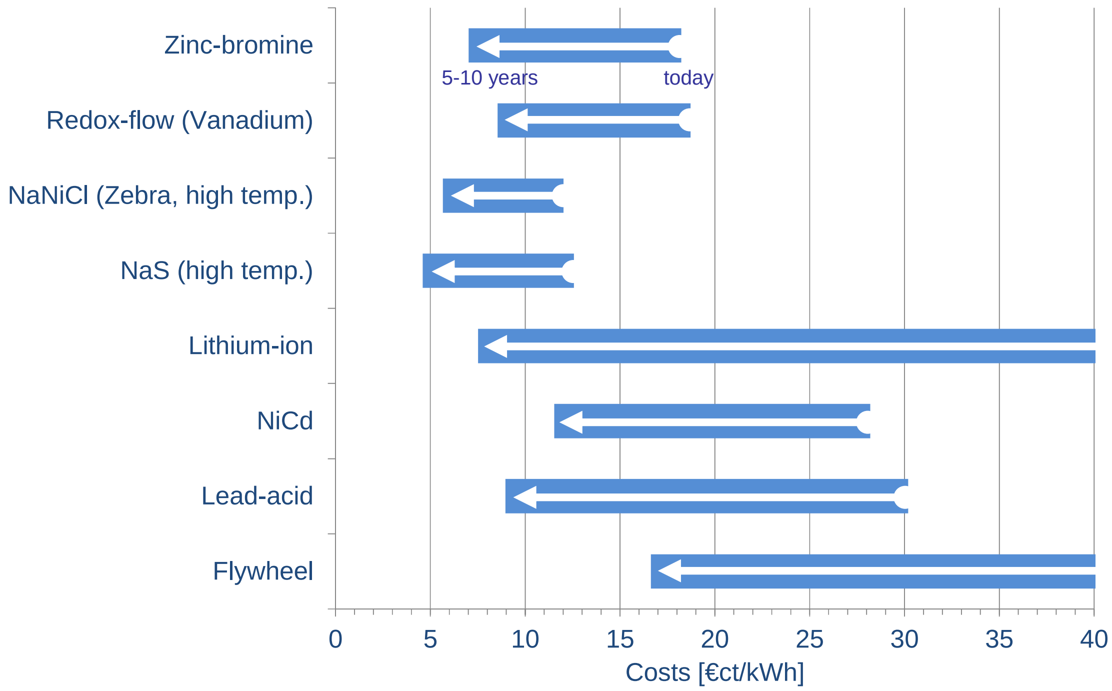
Source: LBST based on reference case 1 of [VDE 2009]

Figure 24: Comparison of full costs for storage systems for peak-shaving in the medium-voltage grid



Source: LBST based on reference case 3 of [VDE 2009]

Figure 25: Comparison of full costs for storage systems for peak-shaving and load-levelling in the low-voltage grid



Source: LBST based on reference case 4 of [VDE 2009]

Demand Response (also increase in Energy Efficiency)

Main benefits drawn from the application of DR actions include:

- A reduction in the required **generation capacity** resulting from a decrease in the system peak load as a consequence of the application of time varying electricity prices (several pricing mechanisms are possible like **Real Time Pricing** (RTP), **Critical Peak Pricing** (CPP) or **Time of Use** (ToU) **Tariffs**) or, to a lesser extent, the provision of feedback to consumers on their electricity demand (overall level of consumption and timing of this consumption);
- A decrease in the total **electricity consumption**, which is mainly triggered by feedback on consumption. According to a review carried out within [Olmos et al. 2011] on the results of studies on the potential benefits of the application of different demand response schemes, feedback on electricity consumption provided to domestic consumers can achieve a reduction in total electricity consumption of about 5% on average, and a reduction of the system peak load of about 7-8%. Time varying pricing schemes can only achieve modest reductions of the total electricity consumption in the system (probably not larger than 1-1.5%), while peak load reductions achieved by the latter in normal days could range from 5 to 8% depending on the pricing scheme applied (ToU tariffs without automation of the response of load tend to be less effective than other mechanisms like RTP with load response automation), see [Olmos et al. 2011].

Using data from ENTSO-E 2009-2020 System Adequacy Forecast; [Vasaaet et al. 2008]; NORDEL, Annual statistics 2008-2009; Energy Statistics of the UK System-2009 from the Department of Energy and Climate Change; and IEA Energy Statistics 2008, an estimate was made of the overall potential reduction in peak generation capacity and electricity consumption that could result from the implementation of DR schemes in most EU countries (see Table 7).

Table 7: Potential peak load and electricity consumption reductions resulting from the application of DR actions in European countries

	DR Potential Savings Electricity Consumption [Consumption of Equivalent Cities]	**DR Potential Savings Peak Generation Capacity** [Number of Equivalent Power Plants]	**Electricity Consumption 2009** [TWh]	**Generation Capacity 2009** [GW]	**Ratio for Electricity Savings**	**Ratio for Generation Capacity Savings**
GR	1.1	5	56.3	12.4	0.0195	0.4032
IR	0.4	2	27	6	0.0148	0.3333
FI	0.8	5	83	17	0.0096	0.2941
PT	0.6	4	52.2	16	0.0115	0.2500
UK	4.2	23	378.5	94	0.0111	0.2447
FR	4.1	26	494.5	118	0.0083	0.2203
DE	5.5	28	557.2	129.5	0.0099	0.2162
SW	0.9	7	137	34.1	0.0066	0.2053
NL	0.9	5	120.3	25.2	0.0075	0.1984
AT	0.6	4	68.4	21.3	0.0088	0.1878
BE	0.5	3	89.5	17.4	0.0056	0.1724
IT	2.4	17	337.6	102.2	0.0071	0.1663
DK	0.2	2	34.5	12.6	0.0058	0.1587
ES	2.6	14	274.1	90.2	0.0095	0.1552

Data:
ENTSO-E, System Adequacy Forecast 2009-2020; Demand Response, a Decisive Breakthrough for Europe. Report by CapGemini, Vaasaett and Enerdata
NORDEL, Annual statistics 2008-2009
Energy Statistics of the UK System-2009. Department of energy and Climate Change
IEA Energy Statistics 2008.

As shown in Table 7, **potential reductions in generation capacity** range between 15.5% for Spain and 40% for Greece, while potential reductions in electricity consumption range between 0.5% for Belgium or Denmark and 2% for Greece. These **benefits are remarkably large** compared to the potential implementation costs of DR in most countries, provided that the potentials are achieved. DR mechanisms are already being applied to **large consumers**, while their application to **small ones (households)** has, in most systems, only been tested in pilot projects. **Previous estimates** of the potential electricity savings from DSM are, in any case, much more modest than those of the potential savings from DSM through the **development of a Smart Grid** provided in [EC 2010a], where the authors state that smart grids could reduce the EU's annual primary energy consumption in the energy sector by almost 9% by 2020, which amounts to 148 TWh of electricity or savings of almost €7.5 billion considering 2010 prices. Obviously, not all potential savings will be achieved in reality, since they are normally computed assuming that all economic opportunities to reduce system costs (in this case through load reduction at peak load times and overall) are realised. Savings will actually depend, among other things, on the nature of the DSM mechanism implemented, the response of consumers and the characteristics of the specific system considered.

Results computed for different countries may consider slightly different assumptions. There is no reference, for example, to the level of RES penetration considered in the different countries when performing the corresponding analyses. **Sensitivity analyses** to assess the impact of assumptions on the results obtained **have not been carried out** either.

Electric mobility

As already explained in section 2.6.3, the main benefits brought about by the use of EVs are related to the substitution of gasoline by electricity or hydrogen as a transport fuel. As in other cases the literature is patchy. However, the following conclusions can be drawn:

- EV penetration is generally assumed to be small in 2020 (1-5% of the total vehicle fleet) growing to more significant values in 2030 (up to 20%).
- Main economic gains come from the substitution of expensive oil products for relatively cheaper electricity (more than half cost savings). Most of the additional cost comes from the possibly greater car cost and also from the required charging stations (850 to 9200 €/vehicle).
- EV electricity demand for vehicle charging or electrolytic hydrogen production for fuel cell vehicles is relatively small when compared with the total electricity demand. Therefore the required investments in generation or transmission capacities are likely to be marginal.
- Distribution electricity network reinforcement costs can be very low if smart grid techniques, including smart EV charging, are applied. Otherwise significant investments can be required (possibly up to 30% of additional investment). Smart charging can also significantly contribute to avoid wind spillage.
- Economic benefits coming from the possibility of transferring energy from the vehicle to the grid seem to be marginal.
- Similar conclusions are drawn for hydrogen, which, however, has different characteristics. This includes easier integration of hydrogen production in the electricity grid as electricity consumption occurs in stationary installations, ranging from decentralised systems at refuelling stations to large-scale facilities combined with long-term underground storage.

An overview of the most important studies in this area is provided in Annex 4.

Supply side management

A number of studies forecast the future generation mix in Europe over the next decades. As variable generation penetration increases, the total energy to be supplied by the remaining generation greatly decreases, although the required capacity for supply when variable generation is not available decreases much less. As a consequence,

- **Power plants with low-capital/high-fuel cost become favoured** over high-capital/low-fuel cost ones and can likely attract most of the investment in traditional power plants.
- Low-capital/high-fuel cost plants (e.g. gas turbines) happen to usually be more **technically flexible** than the alternative ones. That results in a more flexible system even if flexibility as such (e.g. ramping times, cycling periods, minimum power production and the like) is not considered or valued in the analysed studies.
- There is almost **no information** on the costs that more frequent cycling (that is, a greater number of start-ups, shut-downs and generally ramping operation) can impose on fossil-fuel power plants.

An overview of the most important studies in this area is provided in Annex 4.

Desirable features of assessing benefits and costs

In this subsection, the main features of the process of computation of the system benefits and costs resulting from the construction of energy infrastructures are discussed. Given that benefits and costs of new infrastructure are the drivers of its construction, they should be obtained as a necessary by-product of the infrastructure expansion planning process. Due to the regional dimension of the relevant market where these infrastructures are going to be operated (i.e. the European market), the expansion planning process to be considered must also have a European scale. Main features of the EU transmission problem follow:

- **Time horizon**: When discussing strategic infrastructure/transmission planning, it is not necessary to go as far as 2050 (other studies, as the ECF, have gone to 2050). We might try to obtain expansion trajectories from 2010 to 2050 or just explore a few characteristic time horizons (2020, 2030, 2050 and how they are related);
- **Geographical span**: According to studies by ECF, the total costs for high renewable scenarios could be 40% lower if resource optimisation takes place all over Europe;
- **Scenario(s)**: There is much uncertainty, in particular considering: deployment of renewables including major projects, other generation, CO_2 targets (more or less included in previous items), demand growth, merit order of fuels, available generation technologies, and available transmission technologies. Chapter 1 identifies the Greenpeace scenarios as reference for this study. However, a proper planning exercise should include a much wider range of scenarios than those provided in [Greenpeace and EREC, 2010];
- **Major options** (hybrid options might be possible) to explore in transmission/infrastructure expansion: reinforcements of existing lines, overlay at higher voltage AC, overlay at higher voltage DC, extensive use of other technologies like FACTS to increase the utilisation of the network;
- **Geographical granularity**: Transmission (400 and 220 kV) network with a large number of nodes (as much as 5000 to 10000 if the aim is to plan the expansion of the European grid) and also lines.

Note that the ENTSO-E pilot TYNDP for the EU has 500 reinforcements. It has not been obtained by any kind of systematic search, but by aggregation (bottom-up) of the plans of the European TSOs;

- The **decision making process** is multi-attribute: See the reports from the projects PLAER, RealiseGrid or SUSPLAN, as well as the corresponding chapter in ENTSO-E TYNDP;
- An **expansion planning** approach whose objective is to identify the transmission/infrastructure facilities to be built has to take into account at least: the uncertainties/scenarios; the actual network topology; the discrete nature of the investments; a set of load/generation operating conditions for each one of the years to be considered that are representative of all those others that may occur; the time chronology (time series) of power system states; and a set of contingencies for each one of the years to be considered that allows one to capture the reliability benefits of investments;
- A relevant issue when allocating benefits and costs to specific parties (agents/network users) in the system relates to the definition of the **counterfactuals, or alternative situation** to that in which the concerned piece of infrastructure is built. This is central to computing a reliable estimate of the extra benefits obtained and of the costs incurred by each party as a result of the construction of the (piece of) infrastructure considered. The counterfactual should be defined as the most credible alternative situation to that in which the infrastructure investment takes place. The process of allocation of the transmission costs according to the benefits obtained by agents from network reinforcements is discussed, among others, in [Hogan 2011].

Additional considerations on the design of the cost-benefit analysis to be used in order to assess the construction of new grid reinforcements are provided in [Migliavacca 2011].

2.6.5. Concluding remarks

Computing the benefits and costs of possible infrastructure investments is required both to determine **which infrastructures to build** and to be able to properly **allocate the cost** of these infrastructures to system stakeholders, which may be critical to obtaining construction approval.

Infrastructure investments associated with the integration of RES generation at RES level may bring about substantial benefits beyond the expected increase in the level of RES energy that the system can safely absorb. **Extra benefits** of transmission are mainly related to the increase in the level of integration achieved among EU power systems. Benefits of storage capacity, demand response and generation response are expected to be predominantly of a local nature.

The **costs** incurred when building and operating these infrastructures **will probably be significantly lower than the benefits obtained**. However, investments in different types of RES-associated infrastructure (or those in distant RES generation plus the required transmission connection capacity) may exhibit a **high level of substitutability**. Hence, benefits and costs of the different possible infrastructure investments should be compared to determine which one to carry out.

Some of the benefits of infrastructure cannot be expressed in economic terms. Others can, but are **highly sensitive to assumptions made** on the operation conditions in the system. There is generally a lack of reliable data on infrastructure costs and benefits.

In order to carry out appropriate cost-benefit analyses, the high level of uncertainty about the future evolution of the system should be taken into account. This, coupled with the large size of the relevant system to analyse (as big as the US or the EU), constitutes an important challenge to get accurate enough estimates of benefits and costs.

2.7. Relevant actors, investors and the EU role

This subchapter will introduce the roles and the different interactions among stakeholders and policy makers. Part 2.7.1 will look at the implications of RES integration into the network systems for those directly involved in the building, updating and running of energy infrastructure, such as Transmission system operators (TSOs), Distribution system operators (DSOs) and the energy regulators. This part will also provide an overview of the respective EU representative associations: ENTSO-E and EDSO. Part 2.7.2 will look at the major current investors in large energy infrastructure projects and the most common types of financing. The final subchapter 2.7.3 will examine the role that the EU institutions play in this context.

2.7.1. Infrastructure operators and energy regulators

Transmission system operators (TSOs)

The foundation of the European energy network was **built mostly after World War II**. Its overall structure and administration were developed according to the needs of an emerging high-consuming power society [TYNDP 2009], and its operational systems designed according to the needs of a large centralised energy production system with a focus on large coal plants, nuclear stations and hydro power plants [Altman et al. 2010b].

Because of these characteristics, the national energy networks have been governed by large, regulated TSOs, usually in charge of power (electricity) transmission from the centralised power station to the main high voltage infrastructure. European TSOs are directly in charge of the maintenance, update and enlargement of the grid infrastructure, it is therefore them that usually take charge of large infrastructure development plans [TYNDP 2009]. Their role is thus fundamental to promote the integration of RES into the network system through the deployment of cross-border transmission and the implementation of new interconnection projects, provided that they act in a coordinated and efficient manner.

In 2008, the European Network of Transmission system operators (ENTSO-E) was established with the purpose to coordinate TSOs' action at the European level, to promote the development of a pan-European electricity grid and to lead to the establishment of the internal electricity market [TYNDP 2009]. ENTSO-e has grown into being one of the major actors in the EU scene; the organisation's main goals are modelled on the basis of the three main pillars from the third legislative package, i.e. security, sustainability and internal market. ENTSO-E is composed of 41 European TSOs from Member States and associated partners and speaks for all EU TSOs [ENTSO-e website] with regards to all technical and market issues.

All together, the **41 TSO members of ENTSO-E run over 305,000 km of transmission lines, with over 828 GW of power generation and 525 million citizens served** [Chaniotis 2011]. ENTSO-E also develops the TYNDP, which is a non-binding agreement monitoring and coordinating all projects of European interest. ENTSO-E has the possibility, in the context of the second TYNDP (2012-2020), to push for those projects that are specifically issued in relation to the integration of renewable energy into the network system.

The role of TSOs is expected to be more influential also thanks to the recently launched European Infrastructure Package (EIP). The proposal for "guidelines for trans-European energy infrastructure" provides for the establishment of a number of **"Regional Groups"** based on individual priority corridors; each Group will be composed of TSOs, MS representatives and national regulatory authorities. If implemented as such, the role of each group will be to define a list of projects of common interest according to the priorities of each European region[32].

Not all European TSOs are directly involved in the process of RES integration in the energy network. For instance, the **national TSO in the Czech Republic, ČEPS**, which runs a total of 5,483 km of high voltage lines, is responsible for connection of energy sources with installed capacity higher than 50 MW: the only renewable energy source ČEPS lines are connected to is a single wind park. According to the company original statement on the integration of renewables, *"ČEPS's role consists only in highly accurate forecast of RES electricity generation within individual distribution systems, its assessment in terms of maintaining supply and demand balance in the Czech power system and the issuance of dispatch instruction to reduce RES electricity generation within particular distribution systems after having used all the other tools for maintaining supply and demand balance"* [ČEPS position document 2011]. In such cases, it is the local DSO (see below) to be directly responsible for the system updates to promote integration of renewable energies in the network system.

Distribution System Operators (DSOs)

DSOs, which are also mostly regulated, are in charge of the lower voltage electricity distribution from the infrastructure to the individual consumer. In most European countries, the distribution companies are responsible for **upgrading the lower voltage distribution lines** rather than building totally new infrastructure capacities [TYNDP 2009]. Since the integration of RES in the network system will also require an evolution from a centralised, coordinated system to a decentralised one, in terms of both systems management and production, DSOs will have to work in parallel with TSOs in order to achieve the best results from both sides.

EDSO for smart grid is the European association representing 32 distribution operators across Europe. The increase in renewable energy production and the challenges due to their integration in the network system prompt for major changes in the role of European DSOs [Interview with EDSO]. The two main drivers of this change will be:

- Distributed energy generation;
- Demand side management.

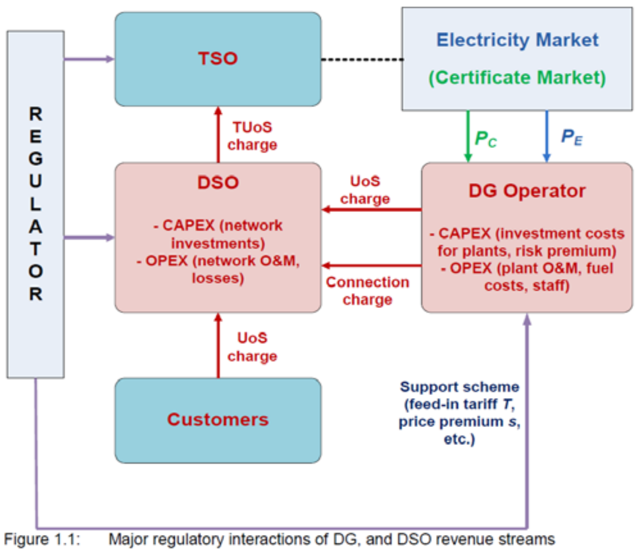
It is important for DSOs, and therefore EDSO, that this change in role will be acknowledged soon enough by all other actors and authorities, such as regulators and national/European institutions. While EDSO acknowledges the need for higher grid capacity, **the biggest change brought about by DSOs will be the introduction of smart meters and demand side management**. In relation to this, EDSO will begin a process of research and collaboration with ENTSO-E to ameliorate the current system of grid codes [EDSO 2011].

32 COM(2011)658final.

Energy Regulators

Energy regulators play an important role in RES integration. Figure 26 provides a schematic overview of the interaction between DG producers, TSOs/DSOs and the regulators. As can be seen, it is the energy regulators that define the mechanisms of interaction between the TSOs and the DG operators. The European landscape is extremely diversified: for instance, in some cases energy regulators are not directly involved in the implementation of legislation to promote RES production, in other instances they are; in any event, the interactions between energy regulators and TSOs/DSOs have repercussions on all the actors concerned.

Figure 26: Regulatory interactions between DG, DSO and TSO actors in the electricity market



Legend: TUoS: Transmission Use of System charges (tariff on the use of the transmission network, from DSO to TSO); UoS: Use of System charges (from consumers and DG operators to DSOs). The chart displays the interactions between the main stakeholders in the energy sector: producers, grid operators, final consumers. The overall picture is dominated by the role of the energy regulator, which determines the charges, tariffs, CAPEX and OPEX rates.
Source: [EWEA 2010]

Of particular importance in the future will be the role of the **Agency for the Cooperation of Energy Regulators (ACER)**. Similarly to ENTSO-E, ACER has been established under the third legislative package, with the purpose to foster and implement cooperation among European energy regulators in the building up of a pan-European energy infrastructure system. Two major tasks have been assigned to ACER: firstly, the association has been in charge of preparing the framework guidelines for network connection (Network Codes). The Network Codes, to be further discussed in chapter 4, will then be drafted by ENTSO-E, while ACER will have the possibility to look into the document in order to assess its relevance with respect to the initial guidelines.

With the introduction of the European Infrastructure Package, ACER will secondly be in charge of monitoring consistency between the list of projects of common interest presented by the Regional Groups and the overall Community goals.

Energy Producers

As explained above, the role of TSOs and DSOs is expected to change with the introduction of decentralised energy production; in a similar fashion, other market players are expected to take a more central role within the management of the power system.

With respect to system management, energy infrastructures are expected to increasingly rely upon **ICT infrastructures** in the future. ICT companies will come to play a major role, especially in relation to the development of new types of software and control mechanisms that will allow all involved parties to coordinate power production and consumption at different levels. These companies will have to interact with energy actors and ensure that the highest safety standards are applied at all time.

Consumers will also be involved in a more proactive manner. On one side, the end-consumers will be empowered to take decisions and promote efficient deployment of resources thanks to smart metering deployment. Also, with smaller scale decentralized energy production, **"prosumers"** (a term specifically coined to indicate those consumers who are also producers) will be able to influence decision-makers into promoting better policies for renewable integration.

Energy producers will also have to play an important role in the integration of RES into the network system. Before the application of the third legislative package, most energy suppliers were integrated with the DSOs, which simplified the process of control and regulation of energy resources. The introduction of market **unbundling** has created a more complicated communication system between the two [ECN 2005]. In the current market model, energy suppliers may see their profit damaged by further RES penetration and market integration because of a negative effect on prices in the high prices market. Energy producers will have to find new business models and services to customers in order to compensate their lost revenues [ECN 2005].

Finally, a whole array of actors including universities, research institutes and consultancies, will have to be involved in the process in order to help spread knowledge and promote excellence.

2.7.2. Investors

The EC estimates that from 2011 to 2020 **around €1 trillion** should be invested in expanding and upgrading the European grid [European Commission, 2010b]. The EC also estimates that, of these, €200 billion should be dedicated to the development of transmission networks alone; the private sector is expected to cover 50% of this investment [European Commission 2010b], although there are concerns regarding its capacity to do so.

A recently published report commissioned by DG Energy on the status of the financing situation of European energy infrastructure projects provides a complete overview of the current configuration of infrastructure investment in Europe and future needs [Roland Berger 2011].

For the year 2010, the study estimates that European **TSOs have invested** in network extension (electricity and gas infrastructures) €9.1 billion per annum, compared to an annual requirement of around €20 billion per annum to achieve EU 2020 targets. The trend is expected to increase, with an annual average of €14 billion for the years 2010-2020 [Roland Berger 2011].

Concerning the methods of financing, the authors observe that the majority of TSOs finance large infrastructure projects through **corporate finance rather than project finance:** investment decisions are therefore taken on account of the company balance sheet rather than the expected returns from the project itself.

The three major sources of financing for TSOs infrastructure investment projects are loans from IFIs and commercial banks, along with a smaller share of corporate bonds.

The **European Investment Bank (EIB)** is the most important credit provider for large infrastructure projects, given its capability to provide long term loans under advantageous conditions [Roland Berger 2011]. The level of investment of the EIB in the energy infrastructure sector has more than doubled its value since the latest financial crisis, from €2.5 billion in 2007 to €6 billion in 2010. The overall amount is equally shared between transmission and distribution lines [Roland Berger 2011]. Additional financing instruments indirectly monitored by the EIB are **infrastructure investment funds**, through which the EIB attempts to promote the EU renewable energy target and gas emission reductions [De Jager 2011].

Nevertheless, EIB funding for the infrastructure sector will be decreasing progressively in the next years, and **corporate bonds and private equities** will have to cover a bigger share of the total amount of investments in energy infrastructures. This will turn out to be a challenge for policy makers, who will have to implement reforms enabling an attractive financial environment for institutional investors. This issue is further analysed in chapters 3.4.1, 4 and 5.

In view of the large scale upgrade required at the distribution level, it is still unclear who will be responsible at the European level for financing smart technology deployment. In countries with high penetration of **smart meters**, such as Italy, Sweden and Finland, DSOs have a clear mandate to take responsibility on planning and financing. In most other countries, given the absence of a plan for smart metering roll-out, the role of financing projects in this field has not been assigned yet [Eurelectric 2011].

2.7.3. European institutions

The law-making European institutions – the European Commission (EC), the European Parliament and the Council – are expected to play a major role in setting **clear goals** and preparing a **well-defined roadmap** to help stakeholders in their long term investment planning for the deployment of energy infrastructures. Their roles and responsibilities have been changed since the entry into force of the Lisbon Treaty.

Through legislative proposals, the **EC** has the power to influence MS decisions with regards to renewable integration policies. The role of the EC is also that of ensuring the best possible coordination of EU projects, to avoid duplication of efforts and to promote knowledge sharing. DG Energy is correspondingly entrusted with the external dimension of energy, including projects of European interests where the Commissioner takes the lead [Braun 2011].

The EC would acquire a prominent role under the provisions of the proposed EIP. By setting the criteria for the selection of **projects of European interest**, the EC would be able to ensure that infrastructure projects necessary for the integration of RES into the network system and the integration of the European energy market will be completed in the best possible way. Under the provision of the proposal, the EC would also be in charge of establishing the Regional Groups for the selection of projects of common interest and monitoring the process from its inception.

While MS will be allowed to select their own authority charged with dealing with administrative procedures, it will be possible for the EC to nominate a European Coordinator if a project encounters major difficulties and delays [COM(2011)658final].

With the Lisbon Treaty, the **EP** has seen its competences increase in a number of areas including the energy field. As the only directly elected organ of the European Union, the role of the EP is fundamental in providing full political support to the smooth deployment of renewable energy projects and in representing EU citizens' concerns vis-à-vis the EC and the Council.

The role of the EP and its representatives might increase also with regard to public acceptance. MEPs are expected to play an important role in dealing with issues of social resistance at the local level, for instance by explaining to their constituency the need for an integrated European infrastructure network, stressing the role of renewable energies to which individuals are less opposed.

The role of the **Council** with respect to energy policies remains mainly unchanged, the main difference being the increased share of co-legislative power with the EP.

2.8. Milestones of infrastructure roll-out and investment

The **availability of financing** through the proposed COM (2011) 665[33] can be a decisive factor for cross-border projects that contain difficult and uncertain cost and benefit allocations. The **priorities** listed in the proposal include several ones that have been assessed as important for the integration of renewable energy. Northern seas offshore grid will help to tap into offshore wind resources and enable more cost efficient energy balancing for Central Europe through increased connections to the Nordic reservoir hydro resources. North-South electricity interconnections in South-Western Europe ("NSI West Electricity") will strengthen the currently weak connections from Iberia and Italy, especially to Germany and the UK. These countries have the largest targets for variable renewable energy in absolute terms. Also, the North-South electricity interconnections in Central and South Eastern Europe ("NSI East Electricity") will help the integration of variable generation, although the most important driver in that case is likely to be market integration. The Baltic Energy Market Interconnection Plan in Electricity ("BEMIP Electricity") will more strongly connect the Baltic countries to North and South. In absolute terms, the 2020 plans for variable renewables are limited for this region, but the connections will help to integrate the relatively good wind resources also in the longer term.

The **milestones for infrastructure roll-out** could be based on selected priorities (using e.g. the COM (2011) 665 list). However, the literature reviewed in this chapter does not provide the means to assess whether these prioritisations would set good milestones from the perspective of renewable energy deployment in Europe. The most reliable view of transmission development needs for the next ten years comes from the ENTSO-E TYND process, which is supervised by ACER. However, the first **TYNDP (2010)** was a pilot project and its results were mostly based on a bottom-up approach. The future TYNDPs, especially those informed by the results from different ongoing and **future research projects** (including MoDPHES), will build a more informed view on transmission priorities.

The build-up of the European grid to support high amounts of variable generation implies investment costs in the range of tens of billions of Euros (e.g. EC 2010).

[33] Proposal for a Regulation of the European Parliament and of the Council establishing the Connecting Europe Facility, COM(2011) 665, Brussels, 19.10.2011

Considering the high value of the investments, the research performed so far is **not of sufficient quality** to make informed decisions on longer term transmission priorities or on milestones for European investments in the power grid. The main recommendation is therefore to **improve the data, tools, and methodologies** used in research.

The long-run (2020 and beyond) priority projects in the European transmission system should be based on **European level scenarios** on the long-term electricity generation, consumption, and energy resources. The process should employ the **top-down procedure** in transmission system planning. More innovative transmission solution alternatives, such as **supergrids and offshore grids**, ought to be studied intensively – in these cases the top-down procedure in transmission grid planning is even more important.

Studies that analyse future transmission needs should include proper (at least hourly) **time series for variable generation**, which are currently lacking at European level. They should incorporate **other possibilities to mitigate the impacts** of increasing variable generation, e.g. demand response (including electric heating and cooling), flexible conventional generation, reservoir hydro power, possible pumped hydro developments in the Nordic countries and in the Alps, and other forms of electricity storage, including those at the distribution grid level.

Most of the wind and other RES integration studies carried out at pan-European level have been done without strong participation by TSOs or ENTSO-E and technical network calculations with detailed network models. It is crucial to concentrate on the **European-wide studies with detailed network calculations and simulations**, because many physical aspects setting limitations, challenges, or even imposing problems to the power system, can be only implemented with detailed models. Even the extremely simplified network modelling of the non-TSO studies (e.g. TradeWind, OffshoreGrid, Susplan) contain large error sources (e.g. the NTCs for the future years based on planned or foreseen cross-border connection reinforcements).

The EWIS study stated that developing suitable tools for supporting the final investment decisions is challenging and computationally demanding. A lot of emphasis ought to be put on this TSO work, and data transparency should be increased in order to improve the supporting research and education in universities and research institutes.

Lastly, the EC has published a new **Energy Roadmap 2050** in December 2011. It presents new scenarios to be analysed and discussed. Furthermore, the EC has a goal to set 2030 targets for renewable energy in 2013.

3. Interplay with other energy policy goals and legislation

KEY FINDINGS

- Integration of renewable electricity into the network system and in the **internal market** provides opportunities but also risks. Increasing the transmission capacity will reduce congestions and allow for more electricity to be traded in the market. Offshore wind integration and the development of Network Codes can also serve internal market goals in relation to infrastructure deployment and trading. On the other hand, the current methods used for power balancing also hinder the integration of renewable electricity, since balancing resources are not shared among main actors. The greater need for backup capacity implies that flexible, (mostly) fossil-fuel based thermal capacity will still be required in the transition phase to a low carbon economy.
- Integration of renewable electricity into the grid can **benefit** the **security of energy supplies** by reducing the need for imported fossil fuels, thus reducing the political, transport, price volatility, resource availability and environmental risks associated with fossil fuel imports. In addition, renewables help improve energy conditions in rural or isolated regions.
- Renewable energy sources also imply certain (new) **risks with respect to security of supply.** These include new import dependence risks, mostly related to biomass and solar energy (e.g. from North Africa), but also related to material inputs (e.g. rare earth minerals). More importantly, the **natural variability** of some renewable energy sources (e.g. wind and solar) is likely to play an increasing role in security of supply considerations. However, the challenge of providing a stable and secure electricity system is **far from insurmountable**, even at high penetration levels. There are various options to facilitate the integration of variable renewable energy technologies into the existing power systems.
- The combined **merit order effects** of CO_2 emissions reduction policies and renewable electricity support policies have distributional effects, which need to be taken into account by policy-makers. While an increasing EU ETS allowance price can lead to an increase in electricity prices and windfall profits for the electricity generating sector, additional generation capacity resulting from renewables support can deflate electricity prices, thus potentially making future investments unprofitable. It is thus advisable to closely align climate and renewables policies from a distributional point of view.
- The **impacts of renewable energy infrastructure on nature** are still rather limited, mostly due to the still rather low penetration of renewables in the energy system. With increasing market penetration, the potential risks of renewable energy deployment on the natural environment will need to play an **increasing role** in EU energy policy. As good sites with high renewables potentials and low risks for nature and wildlife become scarce, early spatial planning and site selection with broad stakeholder participation will be key to avoid conflicts. The **Natura 2000 Network** sets a solid framework for the reconciliation of economic activities with environmental objectives.
- Four types of **flexible mechanisms** are foreseen in the Renewable Energy Directive: statistical transfers between MS, joint projects between MS, joint projects between MS and third countries, and joint support schemes. However, a summary of

the national forecasts published by the European Commission in 2010 shows that flexible mechanisms will probably play a limited role. It finds that less than 1 percent of the total renewable energy needed in 2020 is currently planned to be traded between Member States or third countries.

- The **development, demonstration and deployment (RD&D) of green technologies** need to be further promoted. In particular, EU policy needs to address RD&D organisation barriers by providing for a higher degree of technical and research coordination within the EU. Similarly, market failures and distortions need to be addressed, for example, by providing "bridge financing" to cover technological, market and financial risks in the demonstration and early deployment phases.
- The level of **private investment** within the overall level of investment in infrastructure should be enhanced. This will require a reduction in the level of uncertainty for investors, inter alia by promoting the harmonisation and simplification of regulatory standards at the European level. The **Project Bond Initiative (PBI)** aims at creating suitable financial instruments for the financing of long-term infrastructure projects. Similarly, entitling stakeholders to a higher rate of return for projects of European interest within a system of "priority premiums" should be considered.

This chapter addresses cross-cutting issues between the expanding deployment of renewable energy sources and related networks on the one hand, and a host of other energy policy goals on the other. Policies in support of RES are not necessarily in line with all of these other policy goals (e.g. security of supply or nature conservation); however, most challenges can be overcome when addressing potential conflicts at the early stages of the network expansion. This chapter deals with three concrete aspects of energy policy, which are interlinked with RES, namely the **liberalisation and integration of EU energy markets**; efforts to ensure **adequate, reliable and affordable energy supplies**; and **environmental policy** with a focus on climate change and nature protection. In addition, this chapter briefly looks at the implementation of the RES directive, technology development required for a smart electricity network, and some aspects of network finance.

3.1. Integrated internal market

Both electricity from renewable energy sources (RES-E) integration and the single market objective are key dimensions of the EU 2020 strategy for smart, sustainable and inclusive growth in the EU. However, while RES-E deployment can provide an important stimulus towards greater electricity market integration, several implications of the ongoing large scale RES-E deployment are in **contrast with the single market objective**. These include both technical (e.g. loop flows) as well as regulatory issues (e.g. national support schemes). As the EU's Heads of State and Government have recently declared that the single energy market shall be completed by 2014, resolving these conflicts is of the utmost importance. This section first assesses how an integrated internal market can contribute to RES-E integration and vice versa. Then, the current and prospective drawbacks are discussed. Finally, the analysis reflects upon how the two objectives can be dovetailed.

3.1.1. Potential for synergies

Grid infrastructure is key to achieve both the internal market goal and the cost-effective integration of RES-E in the power system (see Chapter 2). Investments in transmission infrastructure can **benefit both objectives simultaneously**.

They could benefit RES-E integration as destination markets for variable RES-E are enlarged. Integrating regions reduces volatility as different geographical areas have different demand curves [ECF 2010: 70]. Greater geographical spread also means that weather induced variability might equal out – an effect that potentially facilitates variable RES-E integration. Of particular relevance, in the light of the supply development in Northern Europe, is the fact that new corridors could allow exporting wind peak production, thereby reducing wind overproduction and lowering the risk of negative prices. A more integrated electricity market would allow "to balance the location of wind power over a larger region with respect to wind availability, thereby reducing the risk of having high or low wind situations simultaneously" [NEP 2010: 136]. As the spatial correlation of wind power production is higher in the East-West rather than **North-South direction**, the latter interconnections are particularly relevant from a wind power variability perspective [OffshoreGrid 2011: 34]. More generally, the European Wind Integration Study [EWIS 2010: 102], initiated by TSOs to ensure the successful grid integration of wind, concludes that the pan European electricity system needs to be strengthened in order to ensure an improved utilization of variable RES-E.

At the same time, increasing transmission capacity can reduce congestion and therefore allow for more electricity trading. This may lead to a substitution effect – more efficient generators replace less efficient ones – and/ or a strategic effect, if **market competitiveness increases** as opportunities for market power abuse decrease [Migliavacca 2011: 14].

In the past, many potentially profitable interconnector projects were not realised, partly because they were in conflict with important national and company interests [Supponen 2011]. This is related to the fact that interconnectors have a differential impact on prices. In case of stable **price differences between countries**, increased interconnection capacity will allow producers in the low price zone to sell electricity in the high price zone. Consumers in the high price zone gain as prices fall, while consumers in the low prices zone will face higher prices. Vice versa, producers in the low price zone gain as prices go up, whereas producers in the high price zone would have to cope with lower prices. In short, producers in high price zones can be expected to oppose the respective interconnection project.

In order to ensure adequate **incentives to invest in the transmission networks**, the Third Energy Package, and especially Directive 2009/72/EC "concerning common rules for the internal market in electricity", includes effective **unbundling** requirements. However, the implementation of the Third Energy Package is still far from being complete (see Section 3.1.3). But the massive deployment of RES-E may complement the Third Energy Package in further incentivising investments in interconnectors. The reason is that **price difference can be expected to be more dynamic in the future**[34]. This is a result of the variable nature of many RES-E sources.

[34] The positive effect of dynamic price differences can especially be observed for interconnectors linking thermal and hydro-based systems. The former kind of system sees large price differences between day and night, but is not so volatile across seasons. Hydro-based systems, by contrast, have more stable prices during day and night but seasonal and annual prices hinge upon precipitation levels. In this regard, the empirics of the NorNed cable are noteworthy. Depending on precipitation levels, the main direction of the commercial flow changed. According to ENTSO-E's detailed electricity exchange statistics, the Netherlands was a net importer from Norway in both 2008 (2.8 TWh) and 2009 (1.6 TWh). However, in 2010, a dry year in the Nordic countries, the Netherlands became a net exporter to Norway (1 TWh). To simplify: in dry years Norwegian consumers benefit, in wet years Dutch consumers do. In a multiannual perspective, both countries' consumers benefit, as they have lower average prices and less price fluctuation.

In other words, if the wind is blowing and/or the sun is shining, countries may have more RES-E generation than they can integrate in the network. This may even lead to negative prices [IEA 2011]. Building more interconnectors may create a win-win situation for all involved partners. Fewer subsidies would be needed for RES-E due to the higher average capture price. In addition, the interconnector would provide both countries with the necessary flexibility to ensure cost-effective RES-E integration.

One reason for the limited utilisation of interconnectors – [OffshoreGrid 2011: 123] reports an average of 64% for selected interconnectors between 2008 and 2010 – is **internal congestion**. Internal grid extension is also needed for RES-E integration. The **weak North-South link in Germany** is one of the best-known examples. In order to bring wind production from the North to the centres of consumption in the South, internal grid reinforcements are necessary. In principle, these links could also be used to e.g. import electricity from the Nordic countries when the wind is not blowing in Northern Germany.

Offshore wind integration is another instance in which reaching the RES-E goal may bring additional benefits to the internal market. For instance, hubs to connect offshore wind farms can be built with an integrated interconnector. Spare capacity can then be used for trade. Kriegers Flak, potentially operational in 2016, is an example of a project that could affect the cross-border capacity while the main driver would be the integration of the wind power. Up to 900MW of interconnector capacity could be available **between Germany and Denmark** for trade in situations where it is not used by the wind farm. Sweden might join at a later stage [50Hertz et al. 2010].

The development of **European Network Codes** as established in Art. 6 of Regulation (EC) No 714/2009 is another example of how the internal market and the renewable objective can be achieved at the same time. Network Codes are relevant for both cross-border trade and the cost-effective integration of offshore wind farms into the European electricity network.

It should also be noted that "variable generators highly benefit from the possibility of correcting their forecasts close to real time. This requires **intraday trading possibilities** and **short gate closure times**" [Timpe et al. 2010: 42]. Thus, efforts aiming at improving market coupling do benefit variable RES-E integration.

3.1.2. Current and prospective conflicts

The previous section outlined the potential benefits that may arise from new transmission investment triggered by RES-E deployment. One current source of **conflict** between RES-E deployment and the internal market objective is related to **national support schemes**. In order to reap the potential benefits outlined in the preceding section, electricity generated from RES has to be tradable across national borders without obstacles. With a view to offshore wind projects connected to more than one country, [OffshoreGrid 2011: 96] points out that "offshore wind power generation should receive its necessary support irrespective of which country the electricity is flowing to". This does not mean that national support schemes should be fully harmonised, but they need to be compatible. This issue is discussed in detail in section 3.3.1.

Furthermore, variable power flows emanating from RES-E generation far from centres of consumption reserve a growing share of network capacity. Dealing with new variable flow patterns is complex and may cause **loop flows**. This represents both a technical and a regulatory challenge. With regard to the former, [EWIS 2010: 102] points to "flow control optimisation by **operational switching and phase shifters**". In addition, until better forecasting tools are available, variable RES-E imply greater uncertainty regarding the exact location of power generation.

As a result, TSOs may need to use a higher security margin to ensure secure network operation. This decreases the commercially available transmission capacity [Zachmann 2011].

The major regulatory challenge lies in **electricity balancing market integration** as made clear by the newly established Agency for the Cooperation of Energy Regulators [ACER 2011a]:

> "The traditional approach ... – whereby balancing is performed at control-area level and which does not allow for the sharing of balancing resources – may hamper the further integration of **renewable energy** [original emphasis] sources, and the efficient use of the available generation capacities".

In fact, this is a crucial prerequisite for fully reaping the benefits of increased interconnection capacity discussed above. However, due to the high complexity of the subject – practices of TSOs widely differ across Europe – this process will take time. ACER is still in the scoping phase of an **initial impact assessment**. While cross-border balancing can in principle benefit both objectives, it potentially involves a trade-off with commercial exchanges of electricity. This is supported by the ongoing debate, mainly taking place between TSOs and regulators, on whether transmission capacity has to be reserved to allow for **cross-border exchanges of power reserves**. While European regulators used to stress that "cross-border balancing shall not lead to withdrawal of interconnection capacity from market players and neither shall it limit opportunities for cross-border trade" [ERGEG 2009], a recent [ENTSO-E 2011] position paper states that "the trading of reserves requires the reservation of transfer capacity across interconnectors". The position paper recommends reserving capacity on interconnectors "if the social welfare benefits of reserves trading are higher than the benefits from the foregone energy trade due to the reservation of transfer capacity". ACER is currently collecting stakeholders' views on this sensitive issue. A pragmatic approach building upon existing bilateral and multilateral initiatives seems to be the most adequate. The final **"Framework Guidelines on Electricity Balancing"** are expected for June 2012 [ACER 2011b].

The variable nature of RES-E also contributes to another development that is potentially in conflict with the internal market: providing **incentives for sufficient backup capacity**. Notably, the expansion of variable RES-E has an impact on thermal-based power generation that requires more starts and stops. As a result, "the large amount of thermal capacity that essentially operates as a backup ... becomes more valuable for its capacity than its energy output" [Pöyry 2011]. In other words, due to the preference given to renewables, fossil fuel-based thermal capacity can be expected to have a relatively **low load factor**. The problem is that, while studies suggest that in the long-term even a 100% RES-E scenario is possible [e.g. ECF 2010], conventional capacity will still be needed for a transitional period. Accordingly, several Member States consider additional conventional power plants necessary to ensure that supply meets demand at all times – even on the notorious cloudy, windless winter days [e.g. German Federal Ministry of Economics and Technology 2011; Belgian Commission de Régulation de l'Electricité et du Gaz 2011; UK Department of Energy & Climate Change 2011]. In theory, the market would be able to deal with that – as long as no price caps exist – since the costs for backup plants can be recovered through **very high prices at times when RES-E are not able to meet demand**. But it should be noted that large electricity producers with a wide portfolio of generation will usually find it easier to cope with more volatile revenue streams [Hood 2011]. Thus, somewhat ironically from a pro-competition perspective, Member States where **electricity production is still largely in the hands of a monopolist** should have fewer problems to ensure that sufficient flexible generation is available

The fact that several Member States are discussing the introduction of **capacity mechanisms** [e.g. UK Department of Energy & Climate Change 2011] shows that serious doubts exist on whether sufficient conventional generation capacity investment will take place.[35] [Zachmann 2011: 34] notes that "Member States discussions show that those mechanisms risk being non-market based and incompatible across the Union". Potential risks related to the introduction of poorly designed capacity mechanisms include **increasing the market power of incumbents** and causing **unfair cross-payments** between customers and/or generators of different Member States.[36] Radical proposals go as far as suggesting to replace the market with a **central purchaser model**.[37] Apart from the direct threat that such proposals constitute to the internal market, the **uncertainty** surrounding the establishment of capacity mechanisms or market-wide interventions might induce potential investors to delay investment decisions, potentially triggering a vicious circle.

3.1.3. Improving the interplay

Although Directive 2009/72/EC "concerning common rules for the internal market in electricity" entered into force on 3 March 2011, transposition is delayed in many Member States. As of 30 September 2011, the Commission has opened **infringement procedures for non-communication of national transposition measures** against 17 MS. Only the Czech Republic, Germany, Denmark, Greece, Hungary, Italy, Latvia, Malta, Poland, and Portugal have communicated transposition so far. As a matter of fact, it is too early to empirically assess the success of the Third Energy Package. It remains to be seen, for example, how **efficient unbundling** is when both the TSO and a major electricity producer operating in the TSO's control area are owned by the same MS. [Supponen 2011: 146] notes that "even if the ownership is formally separated, there is a risk that at the government level decisions are not taken in an independent manner".

In addition, it is not yet clear whether ENTSO-E – representing 41 TSOs from 34 countries – is able to effectively act in the interests of European consumers.[38] The first **European Ten Year Network Development Plan (TYNDP)** expected for spring 2012 should be carefully analysed in this regard. The pilot TYNDP from 2010 plan was mainly a compilation of national plans. Importantly, the proposal for a Regulation on guidelines for trans-European energy infrastructure [COM(2011)658] stipulates that **projects of common interest (PCI)**, which would benefit from preferential treatment in a number of areas, are selected on the basis of an electricity system-wide cost-benefit analysis following a methodology developed by ENTSO-E. While there will be significant regulatory oversight with both ACER and the Commission involved in the process, this is still a challenging task.

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35 When a capacity mechanism is in place, power plants are remunerated for being available "when required for system balancing or meeting peak demand, and receive further payment through the market for actual generation" [Hood 2011: 18].

36 For example, if Member State A has a capacity mechanism that is paid for by domestic consumers (e.g. through higher network tariffs) and that guarantees a high level of supply security, Member State B - as a consumer of A – will also benefit from this capacity mechanism in an interconnected electricity market.

37 In a central purchaser model, "the regulator determines system requirements for new generation in lieu of the competitive price-based investments of market players" [Hood 2011: 19].

38 Observers also point out the problem that ENTSO-E can determine its governance structure autonomously. Therefore, "it is not clear whether the unanimity issues affecting the regional process in the past will disappear or just moved into the ENTSO" [Squicciarini et al. 2010].

Notably, "benefit evaluation is a [...] demanding exercise" [ENTSO-E 2010: 135] and Chapter 2 has concluded that there is **not sufficient thorough scientific analysis** in this regard. As a matter of fact, it is ambitious to expect ENTSO-E to submit its methodology for an energy system wide analysis only one month after the entry into force of the proposed Regulation [COM(2011)658].

The fact that the newly established **ACER monitors the tasks of ENTSO-E** should allow to verify the latter's effectiveness. Of particular importance in this regard will be ACER's opinion – and, if deemed necessary by the Agency, recommendation – on the TYNDP, as well as its opinion on ENTSO-E's electricity system-wide cost-benefit analysis methodology mentioned above. If ACER's recommendations to ENTSO-E were not being followed, the option to further empower ACER might be considered. As ACER was only launched in March 2011 and faced some delay in the hiring process, at this stage an assessment of its ability to effectively monitor ENTSO-E's work appears to be premature. However, given the wide range of important tasks ACER is entrusted with in the field of electricity alone (e.g. balancing, Network Codes, electricity market monitoring, support to the Commission with regard to electricity infrastructure area, etc.),[39] it has to be ensured that it will be equipped with adequate financial and human resources.

The fact that some **MS fear electricity shortages** in the future should be taken seriously. But as discussed in Chapter 2 and elsewhere, there are at least three more and, arguably, less market distorting, ways to deal with the challenge of integrating large amounts of variable generation into the grid: interconnection, storage and demand response. Introducing capacity mechanisms to attract investment in new flexible generation would be the conventional but not necessarily the only possible solution. While the EU cannot tell MS what to do, incompatible capacity mechanisms – and even more so the introduction of a central purchaser model – would represent a **serious obstacle to achieving the single market in electricity by 2014**. Consequently, the Commission in general and DG Competition and DG Energy in particular should keep an eye on the MS energy policies. MS should be encouraged to at least consider other options before introducing capacity mechanisms.

In case MS are determined to push the issue of capacity mechanisms further, the EU could be involved by encouraging **best practices exchange** and developing **framework guidelines**. Designing an intelligent capacity mechanism that sends the right qualitative and locational signals is challenging. Existing designs of capacity mechanisms favour fossil-fuelled powered plants over low carbon sources, and would therefore need to be adapted [Hood 2011: 19]. **Cooperation across MS** could be a first step in ensuring that capacity mechanisms are not market-distorting and actually solve MS problems. In particular, sharing the **experience from the All-Island Market for Electricity** (consisting of Ireland and Northern Ireland), **Portugal and Spain**, which already dispose of capacity mechanisms, could be beneficial.

3.2. Security of supply

Traditionally, energy supplies have been considered secure when electricity, heat and mobility are supplied on an *adequate, reliable* and *affordable* basis [see also IEA 2009]. The increasing deployment of renewable energy sources (RES) can benefit the security of European energy supplies in several ways.

[39] For a good overview see [ACER 2011b].

The most commonly cited advantages of RES include **decreasing dependence on fossil fuel imports** from politically unstable regions, **unlimited potential of certain RES** (e.g. solar and geothermal), **reduced exposure to price risks and volatility**, as well as **improved energy prospects for rural and isolated regions** (see also [Jansen, Gialoglou & Egenhofer 2005]). However, RES are not necessarily the panacea to all security of supply concerns, raising **new concerns** that need to be dealt with. This sub-chapter analyses three of these concerns: import dependence, variability of certain RES and costs.

3.2.1. The impact of renewables on import dependence

There is a general misconception about the links between renewables, import dependence and security of supply. While it is true that RES can replace fossil fuels to a certain extent and thus positively affect import dependence on these fuels, the nexus between renewables and reduced fossil fuels import dependency should not be overstated. The [European Commission 2010a], for examples, reports only limited effects of rising shares of RES in the energy mix on import dependence. As shown in Table 8, calculations of the PRIMES model show that increasing the share of renewables from 15% to 20% by 2020 will reduce import dependence by 4 percentage points, from 61% to 57%. By 2030, the impact of current renewables policies on import dependence is even less pronounced. Most of this is attributable to decreasing levels of European fossil energy production. Similar conclusions were reached by an assessment of EU energy policy analyses published by the Energy Research Centre of the Netherlands [Groenenberg et al. 2008].

Table 8: Impact of increasing share of renewables on import dependence in EU27

PRIMES Scenario	Baseline Scenario			Reference Scenario		
Year	2005	2020	2030	2005	2020	2030
Share of RES in Gross Final Energy Demand	9%	15%	18%	9%	20%	22%
Import Dependence	53%	61%	59%	53%	57%	57%

Source: [European Commission 2010a]

Note: These figures are based on projections of the PRIMES model. The Baseline Scenario reflects concrete national and EU policies and measures implemented until April 2009. This includes the ETS and several energy efficiency measures but excludes the renewable energy target and the non-ETS targets. The Reference Scenario also includes policies adopted between April 2009 and December 2009 and assumes that the mandatory emissions reduction target and the renewable energy target are achieved in 2020.

Moreover, it should be taken into account that in the long run some **renewable inputs may become tradable across countries**, thus raising additional import dependence risks. This is most likely to happen with **biomass**. Its physical characteristics, namely storability and transportability, allow drawing a parallel between the biomass security of supply risks and those of traditional energy sources, in terms of both **physical availability and prices**. For biomass, competition risks are worsened by the fact that it is used not only for energy uses – such as electricity, heat and transport – but also for **food, fibre and chemical production**. In turn, this leads to price volatility of biomass inputs.

Another import dependency concern is related to solar energy and the ongoing discussion to build a large-scale grid to **import solar electricity** (by concentrating solar power) **from North Africa and the Middle East**.

On the one hand, the project would allow Europe to diversify its energy portfolio by augmenting the share of clean energy sources but, on the other hand, imports of solar power from these regions would further increase Europe's dependence on politically unstable countries. It could even be argued that this kind of import dependency is more problematic than dependence on fossil fuel imports, because large-scale electricity storage remains a technological challenge for the foreseeable future. However, considering that low-carbon electricity from the South is just one potential element of the future electricity supply, these risks should not be overstated. A **beneficial and regulatory framework promoting solar energy imports from North Africa** should thus be created, including options for granting these projects priority status under EU infrastructure projects, as well as promoting the development and operation of **European and trans-Mediterranean super-grids**. Such super-grids would need a high level of redundancy or resilience to avoid becoming easy targets for terrorist attacks.

Similar security concerns have been raised regarding Europe's import dependence on some **key raw materials** required for RES generation. The most prominent example are so-called **rare earth metals**, 97% of which are currently produced by China. Better coordinated efforts by the EU can help to secure supplies of these raw materials in the long-term. The EC proposal for a European Innovation Partnership on Raw Materials and the European Parliament's proposal to include a commitment of EUR 1 million for the establishment of a European Competency Network on Rare Earths in the EU's 2012 budget are steps in the right direction.

Finally, it is important to note that **rising import dependency does not necessarily mean less secure energy supplies**, just as more energy autarchy (e.g. due to a higher share of renewables) would not necessarily reduce the risks of supply disruptions. Global oil and coal markets are relatively open and well-functioning, and **price volatility** is much more of a security of supply concern than import dependency per se. In terms of **natural gas**, however, prices are largely regulated or linked to oil prices, and are thus much less able to balance supply and demand. In addition, the EU is regionally linked to only a few suppliers via fixed infrastructure, which makes the prospect of **physical unavailability of gas more than a concern**. If the EU can increase the share of renewables at the expense of gas imports, this could have a positive impact on security of supply. However, in terms of GHG emissions reductions, the substitution of renewables for electricity production from coal would be preferable. As many renewable energy technologies are subject to natural variability (see below), they are not well suited to serve peak demand, but rather likely to displace typical base load generation plants. The [IEA 2007] thus assumes that "coal, gas, and – in the case of a renewable energy policy, nuclear – are displaced proportionally to their role in the fuel mix".

3.2.2. Variability of renewable energy sources

More important in terms of energy security is the risk of **natural variability** from an increasing share of renewables in the energy mix. With regards to renewables, variability refers to undesired or uncontrolled variability of output (e.g. weather related). Not all renewables are equally "unreliable": **reservoir hydro power, biomass and geothermal**, for example, "present no greater challenge than conventional power technologies" [IEA 2011: 15] for grid integration. **Wind, solar, wave and tidal energy**, on the other hand, are based on resources that fluctuate in the course of a day and from season to season. Also referred to as variable renewable energy (VRE) technologies, they require additional efforts to be integrated into existing power systems [IEA 2011].

Wind, for example, is a VRE because turbines do not operate when wind speed is either too low or too high, as this poses damage risks for the turbines. Solar photovoltaic is subject to seasonal variation from winter to summer as well as to daily variation from diurnal to nocturnal.

In the current EU electricity system, variability is generally not a problem because the penetration of VRE is still low (albeit with strong variations between Member States). Of the total renewable electricity capacity installed in 2010, approximately 44% was based on VRE technologies (33% wind, 10% solar) [European Commission 2010b]. However, the electricity grid will eventually need to adapt to a higher share of variable electricity, which is estimated at 62% of total renewable electricity installed capacity in 2020 (43% wind, 19% solar) [ibid.]. How much variable electricity can be sustained by the grid is still a controversial issue, but it is likely that the **maximum penetration of VRE** technologies will ultimately be determined by economic efficiency and cost considerations rather than by technical feasibility.

The [IEA 2011: 20] concludes that **"the VRE balancing challenge is far from insurmountable"**. In fact, there are several options to facilitate the integration of variable renewable energy technologies into existing power systems. Apart from improving the *tools to forecast* the feed-in of variable renewables based electricity in order to maximise the amount of VRE that can be accommodated in the network, there are other options; this section will focus on five of them, namely optimisation of existing flexible resources; market integration; backup capacity; mixing renewable energy technologies with different natural cycles; and demand-side management.

A key component of the response to increasing VRE shares should be the **optimisation of existing flexible resources**, such as dispatchable power plants (e.g. open-cycle gas plants, hydro plants), storage (e.g. pumped hydro), demand-side management and/or interconnectors to neighbouring power markets. In optimised conditions, the [IEA 2011] found that large shares of VRE can be balanced, ranging from 27% in the Iberian eninsula (Spain and Portugal), to 31% on the British Isles (Great Britain and Ireland), 48% in the Nordic Power Market (Denmark, Finland, Norway and Sweden) and even 63% in the most flexible area in Denmark. Investments in additional flexible resources will thus only be needed if the targeted share of VRE is higher than the potential share of VRE when existing flexible resources are optimised [IEA 2011].

There are several constraints to the availability of flexible resources, the most important of which are **sub-optimal grid strength and market design**. Regarding the grid, the [IEA 2011] recommends to identify grid weaknesses and to examine measures "whereby carrying capacity in weaker areas can be augmented through advanced grid technology and operation techniques" [IEA 2011: 18]. As regards market design, variability can be better balanced when **trading occurs closer to the time of operation**, i.e. through (daily) power exchanges or mandatory pools. Markets relying mostly on long-term bilateral contracts, on the other hand, tend to "lock-up [...] the potential of assets to respond to needs for flexibility that change dynamically" [IEA 2011: 19]. Similarly, regulations restricting the availability of flexible resources should be removed and owners of those resources should be given adequate economic incentives to offer the full extent of their **flexibility** to the market, **both on the supply and on the demand side**. The latter is of particular importance for mid-merit plants (e.g. combined-cycle gas) which are used to address predictable demand changes (e.g. morning vs evening). These may become uneconomic as the share of VRE capacity rises, due to the fact that temporarily high power output of VRE reduces electricity prices (which can even become negative), and that mid-merit plants operate for less time than projected when they were built [IEA 2011]. However, their contribution to balancing VRE output should not be underestimated.

Another option to balance variability of different VRE technologies – as discussed in Section 3.1. – is the **integration of different balancing areas** which increases the size of power markets. However, a recent study by [Pöyry 2011] argues that "heavy reinforcement of interconnection doesn't appear to offset the need for very much backup plant" because "periods of low wind are often correlated across Europe". As a consequence, the study concludes that one should not only rely on "the 'golden bullets' of more interconnection and demand side response". Nonetheless, it recommends building additional interconnectors as they would constitute an important part of the solution. In particular, since hydro power can balance variable sources relatively well, new cross-border transmission infrastructure that would help to better integrate hydro generation and pumping capacity into the European electricity grid could represent an important contribution to the ongoing large scale RES-E deployment in Europe. In addition, new corridors could allow exporting wind peak production, thereby reducing wind overproduction and lowering the risk of negative prices.

Generalising about the amount of **backup capacity** is a futile endeavour, as backup needs depend on a large number of factors, such as the generation mix, the existence of transmission infrastructure, access to storage, etc. Nevertheless, the Roadmap 2050 of the European Climate Foundation (ECF) provides the rule of thumb that "for every 7-8MW of intermittent capacity (wind and solar PV), about one additional MW of back up capacity is required" [ECF 2010: 19].

In addition to optimising the existing flexible resources, market integration and backup capacity, the variability of some renewable energy sources can be balanced by **mixing renewable energy technologies with different natural cycles***.* In general, it can be argued that renewables with higher short-term variability are more risky for supply security, unless combined with renewables with different natural cycles (e.g. wind and solar PV) or appropriate backup capacity. The need for backup capacity for intermittent renewables can be reduced if they are used in combination with a mix of other renewable energy technologies that are less variable. For example, wind power can be complemented by large hydro installations, or possibly even with hydrogen-powered plants.

Finally, appropriate **demand-side management strategies** can help to regulate demand, thus reducing the need for (additional) peaking power plants. By increasing price transparency and setting price incentives, demand-side management strategies can help reduce electricity demand during peak hours. The role of **smart metering systems and smart grids** is of particular importance in load management, and can reduce the need for additional flexible generation capacities.

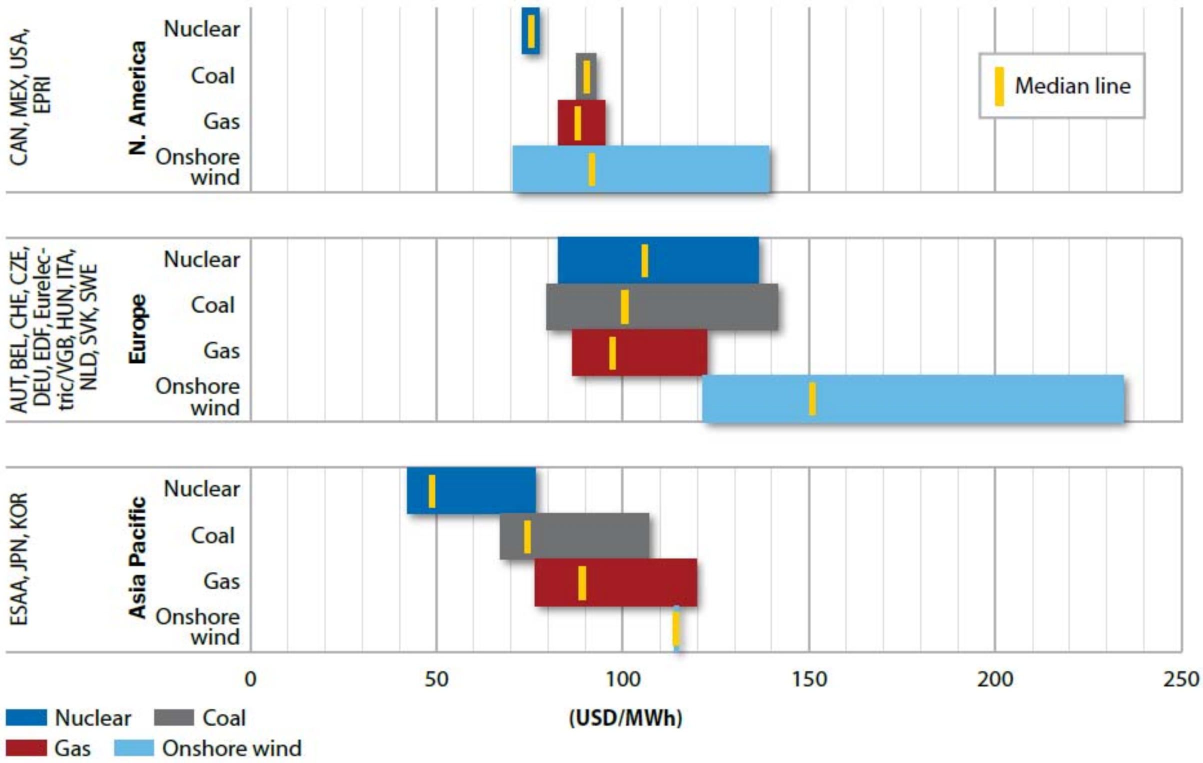
3.2.3. Costs

As regards the affordability of renewable energy sources, the relatively recent nature of most renewables-based technologies does not yet make them very **competitive** from an economic point of view. Table 9 shows the levelised costs of electricity from onshore wind in comparison with conventional sources. In Europe, the average cost of electricity from onshore wind is still about 50% higher than those of gas, coals and nuclear.

However, **renewables** are projected to experience **significant cost reductions**. PV investment costs, for example, have been declining steadily since the 1970s at learning rates of 15% to 22% for every doubling of cumulative installed capacity, and have experienced corresponding reductions in total system costs [Ecofys 2011:12 and IEA 2010b: 20]. Similarly, the PV industry is expected to reduce system and generation costs by more than 50% in the next decade [IEA, 2010b]. Investment costs for CSP have the potential to decrease by 30-40% [IEA 2010c: 270]. On the other hand, investment costs of wind onshore power plants were slightly higher in 2010 than in 2009, ranging between

1125 €/kW and 1525 €/kW. The wind sector has experienced a slight increase in prices since 2005, which can be explained by the rise of energy and raw material prices observed in recent years, but also by "a move by manufacturers to improve their profitability, shortages in certain turbine components and improved sophistication of turbine design factored in" [Ecofys, 2011: 14]. On the other hand, wind turbines have increasingly integrated grid service capabilities and have increased electricity output for the same installed power. In order to make these technologies economically viable, considerable public support is necessary at the level of both investment incentives and changes in consumer behaviour. In order to have a successful deployment, a set of coherent and coordinated policy actions is required in the whole chain of activities concerning a specific technology.

Table 9: Regional Ranges of Levelised Costs of Electricity (LCOE) for Nuclear, Coal, Gas and Onshore Wind Power Plants (at 10% Discount Rate)



Source: [IEA 2010a]

Note: Due to the fact that LCOE are largely determined by country-specific and even local circumstances (e.g. access to fossil fuels, availability of renewable resources, different market regulations etc.), generalisations should be made with care.

3.3. Environmental legislation

In the absence of EU energy policy, environmental legislation has long played a leading role in influencing the EU energy sector. This section assesses the impact of environmental policy on the electricity sector. Particular focus will be laid on **climate change policy** and **nature conservation in the context of the Natura 2000 Network**.

3.3.1. Renewable energy and climate change policy: interaction effects

Cost-effectiveness

Cost-effectiveness is one aspect of the discussions on the interaction between policies focusing on reducing GHG emissions and those promoting RES. In the long run, the combination of RES support policies and emissions reduction ones is likely to lower the overall climate-change mitigation costs and thus to outweigh the increased costs of meeting near-term emission reduction targets.

On the one hand, some studies show that the **costs of reducing carbon emissions** in the short term are higher when RES support is added to a technology-neutral policy instrument, especially one that fixes the quantity of emissions as the EU ETS does. For example, [Böhringer and Rosendahl 2009]'s model shows substantial cost increases for the electricity generation sector in Germany when quotas for the share of renewable energy are added to the quotas restricting emissions. This effect is usually attributed to the availability of technological options for abatement that are less costly at present, such as energy efficiency, nuclear energy and switching to lower-emission fossil fuels. The range of separate objectives embedded in RES policies, such as increased energy security or hedging against fuel price volatility, partly explains and justifies that higher cost (see [Philibert 2011]).

On the other hand, both theory and practice strongly suggest that policy intervention supporting the early use of RES is likely to **reduce the long-term economic costs** of avoiding dangerous climate change. IEA scenarios in the World Energy Outlook 2010 [IEA 2010d] show that renewable sources including biofuels are essential for a share of 24% of the global CO_2 emission reductions to be achieved by 2035. At the same time, the lowest overall cost of mitigation efforts until 2050 may require a RES share of 50% to 75% in global electricity, according to the [IEA 2010e].

As scale and affordability go hand in hand, accelerating the diffusion and thus the economic competitiveness of essential renewable energy technologies could bring them up to a level playing field with conventional energy technologies earlier and ultimately prevent a high-carbon lock-in (see e.g. [Philibert 2011]). This is something the current design of the **EU ETS** appears incapable of achieving, at least due to its inability to provide a global and sufficiently high price signal (see [Egenhofer et al. 2011]). Even in the presence of a carbon price, there are other market failures that impede private sector innovation and investment in technologies at the early stages of their maturity. The most important ones are the learning curve effects that make new technologies cheaper much quicker as their total production and installation volume, in other words their scale, rises in the early stages of their deployment [Stern 2006, Philibert 2011]. Theoretical simulations as well as historic examples from PV industry confirm the significant contribution of RES-support policies to the reduction of costs and market uptake [Breyer et al., 2010; Fischer and Newell, 2008]. Thus, the optimal mix of policies suggested for **least-cost mitigation over the long term** includes a threefold combination of **emission reduction measures, technology learning or scale support and R&D support** [Fischer and Newell 2008; Philibert 2011].

In the EU, further analysis is needed to assess the extent to which the **adopted Climate Change and Energy legislative package** addresses the recommendations for long-term cost reduction of EU mitigation efforts. On the one hand, the targets for renewable energy share in the Renewable Energy Directive (2009/28/EC) appear to aim at supporting the growth in scale. On the other hand, the specific deployment support of RES technologies is left to the Member States, including through utilisation of the proceeds from auctioning EU ETS allowances.

The EU ETS, in its current form, could be considered as having insufficiently contributed to the above-mentioned **cost-effective policy mix**. As the carbon price signal it creates is weak and vulnerable to external shocks of the type experienced under the current economic crisis, further adjustments to its design or to the accompanying legislation appear desirable [Philibert 2011; Egenhofer et al. 2011]. A range of revisions and additions has already been suggested, which might address, among other issues, the cost-effectiveness effects of policy interaction. These suggestions include for example allowance price floors, increasing the unilateral EU emission reduction target, introducing an innovation/technology accelerator, some form of carbon tax etc. [Egenhofer et al. 2011].

Incentives for the dirtiest technologies

An interesting effect of RES support policies in the presence of a fixed emission quantity instrument such as the EU ETS similarly relates to the carbon price. It is commonly argued that such policies lower the price of emission allowances and thus favour the most polluting fossil fuel installations in the EU countries as a group. Keeping in mind that the RES share and the types of fossil fuel installations are unevenly distributed across EU Member States, the support for renewable energy in one country might thus be **indirectly subsidising the fossil-fuel usage in another**.

More specifically, a study by [Böhringer and Rosendahl 2009] outlines this effect. Their model depicts a situation in which a binding quota for the minimum share of electricity from RES is introduced to the power sector, which is already covered by a fixed emission quota, such as the EU ETS cap on emissions. Two effects occur simultaneously but need to be distinguished. First, the electricity production based on fossil fuels is reduced, as intended by the RES quota. However, the amount of total emissions remains the same, because the number of available emission allowances has already been fixed. In a way, all power generators based on fossil fuels are then allowed to emit more per unit of production than before. The relative excess of emission allowances becomes reflected in a lower allowance price. Thus, as a second effect, the most emission-intensive electricity producers, such as coal-powered generators, are able to produce cheaper electricity and thus gain an economic advantage. Compared to the situation before the RES quota was introduced, they would then have an increased electricity output at the expense of a reduced output by the ones using less carbon-intensive fossil fuel technologies, such as combined cycle gas turbines. In reality, the excess emission allowances may be sold on the market to industrial emitters, but the **economic incentive for the dirtiest emitters remains**.

There are **two caveats** to the second effect. **First**, it needs to be further investigated to what extent the model can be applied to the full reality of current and future EU climate change and energy policy. In particular, the Renewable Energy Directive (2009/28/EC) stipulates a 20% target for renewable energy share in final EU energy consumption. This target applies not only to the electricity sector but to all ETS and non-ETS sectors and is differentiated among EU MS. The specific policies to implement these targets as well as the emission-reduction targets in the non-ETS sectors have yet to be designed. **Second**, the long-term perspective analysed in the section on cost-effectiveness above implies that avoiding the **lock-in of fossil fuel technologies** at the expense of RES may be more important for global climate change mitigation than preventing the short-term advantage of one fossil-fuel technology over another [Philibert 2011].

The possible remedies and adjustments to EU policies could be similar to the ones addressing weaknesses in the price signal, as outlined in the previous section. However, the **cross-subsidy effects between MS** might require narrow and targeted adjustments rather than broad and neutral EU-wide measures.

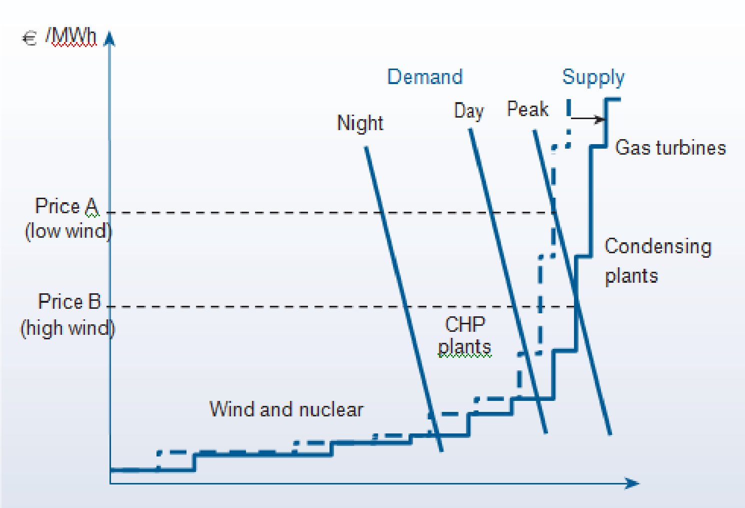
Merit order and distributional effects

The "merit order" effect is what underlies the distribution of wealth from electricity generators to electricity consumers, including industry customers, and vice versa, as a result of CO_2 reduction or RES-support policies. In deregulated electricity markets, a **larger share of electricity from renewable sources** reduces the prevailing marginal variable costs and **benefits the customers** by reducing the market prices of electricity at the expense of generators [Pöyry 2010]. The EU ETS on the other hand increases the marginal variable costs, which are reflected in the electricity prices, and thus provides transfers of rents and **windfall profits to electricity producers and generators** [see Keppler and Cruciani, 2010, Ellerman, Convery and de Perthuis, 2010].

The **separate and combined merit order effects** of these two types of policies have implications for the profitability and investment decisions in the electricity sector, for the distribution of RES-support costs and for the amount of subsidies (e.g. feed-in tariffs) required due to the changing circumstances.

The merit order effect is a result of the **formation of electricity price in deregulated markets**. The price at a given point in time is formed where the supply and demand curves meet and thus reflects only the marginal variable cost of electricity generation [Pöyry, 2010; Philibert 2011]. The supply curve, also called "merit order curve", is based on the cost of producing each additional unit, i.e. the fuel cost, from the range of available generation technologies. Utilities usually charge unit prices at the marginal cost of the last (most expensive) unit produced and thus receive the difference in the form of infra-marginal rents. **Wind generation**, as the largest-scale example of RES-E capacity additions in recent years, has an additional unit cost close to zero (no fuel cost). When a large wind-based generation capacity is added to the system as a result of the RES support, the whole curve shifts to the right, thus **reducing the unit price** that utilities can charge and the associated rent they would get (Figure 27). This benefits the customers to the detriment of all generators, which suffer foregone revenues, possibly making new investment unprofitable.

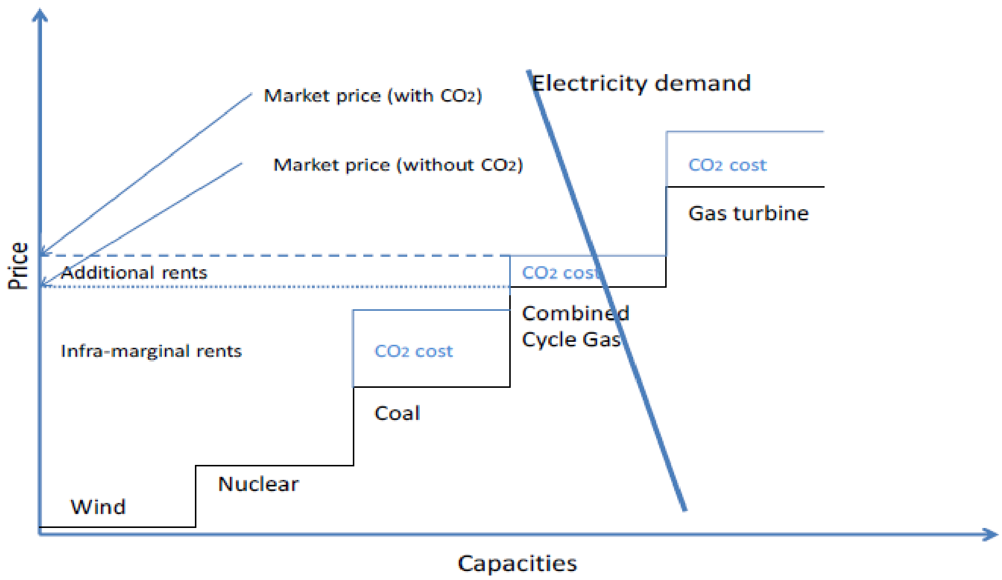
Figure 27: Effects of wind power at different times of the day



Source: [Pöyry 2010, p.11]

The added **EU ETS allowance price has the opposite effect** on the merit order curve (Figure 28). When carbon prices are added on top of the marginal costs of each fossil fuel, the curve as a whole is shifted upwards and the market price increases for any given demand volume. The difference becomes windfall profits for the electricity producing sector and is covered by higher prices for the consumers. According to [Ellermann, Convery and de Perthuis 2010], these rents exceeded €19 billion in the first phase of the EU ETS. [Keppler and Cruciani 2010] confirm this estimate and point out that, although the distribution of rents varies significantly among electricity producers, the electricity sector as a whole will continue to benefit from windfall profits even after allowance auctioning is introduced. In principle, this benefits all electricity generators unless there is no fossil fuel based generation at moments due to renewable production.

Figure 28: Merit order and electricity price increase with CO_2 price



Source: [Philibert 2011, p.19]

Estimates of the **rents or wealth transfers** reveal significant volumes for the merit order effect from increased RES-E share, although depending on the electricity market structure of specific countries. [Sensfuß et al. 2008] show €5 billion in 2006 for Germany and compare this effect to the cost of incentives to RES of €5.6 billion. Thus, the consumers have paid only €0.6 billion of the cost, while the generators have absorbed €2.5 billion in reduced profits. Results for Ireland point to even bigger impacts: one study by [Clifford and Clancy 2011] estimates a merit order effect of €75 million. This balances the €50 million in overall costs from the Irish variant of feed-in-tariffs (FiT) and thus the cost of RES support is not felt by electricity customers.

The merit order effects have **multi-faceted implications for the feasibility of RES support measures**. On the one hand, the above-mentioned quantified effect from increased share of RES-E provides some justification for the costs of RES support policies, since they are not borne by the **consumers**. On the other hand, long-term **incentives for investments** in the electricity sector, including in RES-E capacity, should diminish and would have to be compensated by higher subsidies, such as FiT. This is because, by foregoing the rents they had been receiving earlier, electricity generators experience shrinking profitability. This is added to the fact that **RES-E generators have to cover not only their variable but also fixed costs** [see e.g. Philibert 2011].

The comparatively high long-term marginal cost of producing RES-E (assuming that wind and solar technologies are still in their early stages of maturity) is faced with a lower market price under the new circumstances. An increased amount of the subsidy, such as a FiT, is thus required to cover the difference [see e.g. Frontier Economics 2008]. If a carbon price is however added to these settings, the investment incentives for RES-E capacity compared to fossil fuels naturally increase. In addition to this, the required amount of the subsidy decreases as the merit order effect brings the market price of electricity back up.

Thus, the combined merit order effects suggest that the presence of both CO_2 reduction policy and RES support triggers **distributional effects** stemming from each separate policy. A policy with a strong carbon price signal works in the opposite direction and achieves an increase in the share of RES-E. There is a risk that neither electricity consumers would benefit from a price cut while investments are discouraged, nor would the producers enjoy windfall profits. The cost of direct RES-E subsidies for the taxpayers would also be reduced. Although the merit order discussion appears to support the argument that one would be better off combining the two types of policies, only **further studies and quantifications** of the interaction effects would be able to contribute a definitive statement. This is also the result of IEA analyses (see [Philibert 2011]).

3.3.2. Renewable energy and nature protection

The renewable energy policy of the European Union since the adoption of the 1997 White Paper "has been driven by the need to decarbonise the energy sector and to address growing dependency on fossil fuel imports from politically unstable regions outside the EU" [European Commission 2011a: 2]. Environmental concerns related to climate change and its impacts on Europe and beyond are a key driver for the promotion of renewable energy sources in Europe. On the one hand, substituting low-carbon energy for fossil fuels will **benefit the environment** in a multitude of ways (e.g. by reducing GHG emissions, local pollution and the environmental risks related to the extraction and transport of fossil fuels). On the other hand, it should also be taken into account that the large-scale development of renewable energy infrastructure, including generation capacities and grid extensions, can potentially be in **conflict with other environmental goals** such as nature conservation and the protection of endangered animal species. This sub-section analyses the possible conflicts between the promotion of renewable energy sources and nature and biodiversity policy.

EU Nature and Biodiversity Policy

The centrepiece of the EU nature and biodiversity policy is the **Natura 2000 Network**, which is an EU-wide network of nature protection areas aimed at ensuring biodiversity through the conservation of natural habitats and of wild fauna and flora [cp. Council Directive 92/43/EEC]. It was established under the 1992 Habitats Directive [Council Directive 92/43/EEC] with the aim to assure the long-term survival of **Europe's most valuable and threatened species and habitats**. It is comprised of Special Areas of Conservation (SAC) designated by Member States under the Habitats Directive, and also incorporates Special Protection Areas (SPAs) which they designated under the 1979 Birds Directive (Council Directive 2009/147/EC). In 2010, over **26,000 sites** had been included in the Natura 2000 Network. They vary in size from several hectares to thousands of square kilometres and cover roughly **a fifth of the EU27 land area**, as well as significant marine areas. Around **2000 animal species** are protected under the Natura 2000 Network (e.g. mammals, birds, butterflies, insects), as well as **230 rare and threatened habitat types** (e.g. coastal lagoons, heathlands, flower rich grassland, natural forests).

Human activities (including energy projects and mineral mining) are generally not excluded from the Natura 2000 Network. On the contrary, the Network does not seek to stop economic activities in its sites but rather to set the **parameters** according to which they can take place whilst **safeguarding biodiversity**. Natura 2000's emphasis is thus on ensuring that future **management is sustainable** from the ecologic, economic and social points of view. The Habitats Directive regulates how energy (and other) projects need to be dealt with in order to avoid or limit the deterioration of natural habitats and the disturbance of species. Article 6 of the Habitats Directive requires any project not directly connected with the management of a Natura 2000 site to be subject to an **"appropriate assessment"** of its implications for the site's conservation objectives. If the project is not deemed to adversely affect the integrity of the site, the relevant national authority can agree to it. In case some adverse impacts are expected, certain mitigation measures or alternative options might have to be explored [European Commission 2010c]. A third (but exceptional) option is for a project to go ahead **"for imperative reasons of overriding public interest"**, in which case compensatory measures need to be adopted in order to ensure the overall coherence of Natura 2000. This will also apply to the forthcoming projects of common interest in the context of the proposed regulation on guidelines for **trans-European energy infrastructure** [European Commission, 2011b]. The impact assessment noted that "only a very small subset" of projects of common interest might be in conflict with Natura 2000. It also noted that these projects "are, however, crucial for the achievement of energy and climate policy objectives" [European Commission, 2011b: 6].

Potential Risks of renewable energy technologies and network expansion for nature and biodiversity

Based on the National Renewable Energy Action Plans (NREAPs) provided by the Member States, the [European Commission 2010b] foresees that by 2020 wind power would contribute some 43% of the **total renewable electricity installed capacity** of around 460GW in Europe, while hydro would contribute 29%, solar 19% and biomass 8%. These proportions set the background for the analysis of this section, which focuses on onshore and offshore wind power, hydro power (including related storage technologies), solar PV and CSP, as well as on potential environmental impacts of **new power lines** (overhead, underground and submarine).

The extent to which construction, operation and decommissioning of electricity generation and power lines interfere with nature conservation depends primarily on the technology used and the specific site in question. [BirdLife Europe 2011] distinguishes between **low risk, medium risk and high-risk technologies**. In principle, small-scale technologies with little additional infrastructure requirements are considered to pose only little risk for biodiversity. They include rooftop solar thermal and PV panels, heat pumps and electric vehicles. High risk technologies are mainly liquid biofuels that increase competition for land while failing to deliver emissions reductions, especially new hydro power (also related to pumped hydro storage) when it requires (large) dams and reservoirs, as well as tidal range power in combination with 'high-head' shore-to-shore barrages. Most other renewables technologies and especially the major ones such as onshore and offshore wind, ground mounted solar PV and concentrated solar power (CSP) installations, are classified as medium risk. Most importantly, [BirdLife Europe 2011] notes that these technologies can normally be developed "without significant negative impacts – provided the right policy frameworks are in place and **deployment proceeds sensitively**" [BirdLife Europe 2011: 18].

The main conservation risks associated with **onshore wind power** are **collision risk** (mainly for birds and bats), **disturbance and distancing** due to increased human activity, **barrier effect** (especially in the case of large wind farms) and **habitat loss and degradation** [European Commission 2010c]. Estimates of bird collision rates per turbine range from 0.01 to more than 60 birds annually [Drewitt/Langston 2006; Everaert/Stienen, 2007], with the highest mortalities recorded in large, poorly sited wind farms with high concentrations of birds [BirdLife Europe 2011]. For bats, the figures range between 0 and 50 collisions per turbine per year [Hötker et al. 2006]. Although up-scaling to larger wind turbines reduces the collision rates per unit of electricity output [Smallwood and Karas 2009], even a quite small additive annual mortality in the magnitude of 0.1-0.5% may have an impact on the population size, especially for large, long-lived species with low annual productivity and long adolescence [European Commission 2010c; Langston/Pullan 2003]. It should also be noted that collision mortality is generally underestimated, due to the fact that it is usually measured through carcass search. However, especially the bodies of smaller birds are quickly removed by scavengers or may be overlooked [European Commission 2010c].

Key risks of **offshore wind** development for nature conservation include **disturbance and displacement of mammals** (e.g. dolphins using sonar communication) **and fish**, due to the **noise and vibrations** of the operating turbines, but also in the construction phase, which may cause considerable disturbance to the seabed. **Collision, habitat loss** (which can affect other species on the food chain) and **pollution** due to disturbance of contaminated sediments or through oil and hydraulic fluids leaking or leaching from construction vessels and plant [BirdLife Europe 2011] are other risks to be taken into account. However, offshore wind parks can also have **positive impacts** on the wildlife, due to the fact that trawling is prohibited or restricted inside their area.

Large hydro power, unlike small installations such as run-of-the-river hydroelectricity, can have substantial impacts on the natural environment, some of which are even amplified when these plants are used for pumped hydro storage. Besides **landscape changes**, the most obvious impact includes the **disruption of natural river flows**, which change natural habitats both upstream (due to water reservoirs) and downstream (due to potential alterations between low and high water run-off from reservoirs). Similarly, large hydro power plants can change the **quality** (e.g. lower dissolved oxygen levels or gas super-saturation) and **temperature of water**, with negative consequences for fish and other animal populations. In addition, dams disrupt the natural flows of rivers and migratory pathways of fish, and reservoirs act as major **sediment traps**, interrupting the natural transport of sediment [BirdLife Europe 2011]. Changes in the water level of reservoirs can impact fish populations by altering the littoral zone (close to the shore, with a maximum depth of 10m), which may change the feeding patterns of some species such as trouts [Bakken 2011]. **Indirect effects** of water level fluctuations on birds have been observed, for example, due to decreasing amounts of food (reduced amounts of invertebrates and fish) or flooded or stranded nests [BirdLife Europe 2011]. More rapid and frequent water level changes due to pumped hydro storage can intensify these effects.

Solar PV and CSP have limited negative ecological impacts. One of the exceptions is habitat loss and fragmentation caused by solar array schemes, which can affect bird species such as bustards on open grassland. Fencing may also limit the free movement between populations. Similarly, some insects mistake solar panels for water bodies and lay eggs on their surfaces. This reduces their rate of reproduction, which is of concern if they are an important element of the food chain (e.g. for other endangered species) [BirdLife Europe 2011].

The further integration of European electricity markets and the expansion of renewable electricity generation capacity will require the construction of **new power lines**, increasingly also in remote areas that have potentials for renewable energy. [ENTSO-E 2010], for example, estimates that Europe will need to add some 42,100 km to its existing 300,000 km of trans-European high-voltage power lines in the next 10 years. Since underground cables are the exception due to cost considerations, **above-ground cables** will continue to put animals at **risk of electrocution, collision and loss of habitat**. The risk of electrocution is highest for large bodied species with relatively small wingspan (e.g. storks, bustards, cranes) and birds numerously congregating during migration. Similarly, it is highest on medium-voltage power lines with badly engineered insulator and conductor constructions. [Schaub/Pradel 2004], for example, estimate that some 25% of juvenile and 6% of adult stork die annually from electrocutions and power line collisions. The risk of collision is highest with thin or low-hanging wires in sensitive areas, especially for large birds with limited manoeuvrability and those migrating at night or in large flocks [Haas et al. 2005]. [BirdLife Europe 2011] reports that power lines might result in loss of habitat due to disturbance/displacement or changes in the quality of breeding, staging and/or wintering areas, especially on open landscapes and habitats. **Undergrounding power lines** are not always the solution since they may have some **localised impacts on vegetation**, as drainage may need to be altered temporarily or permanently, causing soil erosion, soil drying and potential disruption of ecologically-sensitive habitat like heathland or peat land, which may take years to recover. Because of their relatively weak physical structure, peat lands are also disturbed by the **heavy machinery** needed to install and periodically maintain underground power lines [Magnusson/Stewart 1987]. Moreover, the presence of underground power lines may facilitate the spread of undesirable plants in adjacent habitats, in particular in fens and peat lands [Dubé 2009]. Underground power lines, nevertheless, present considerable **advantages in terms of bird safety**. Research shows [e.g. Rollan et al. 2010] that collision with human built structures is the largest unintended human cause of bird fatalities worldwide.

Underground power lines are however **more expensive**, in particular for high-voltage transmission. **Overhead power lines** are generally the lowest-cost method of transmission. They present higher transmission capacity and lower upfront and operational costs. Cost differences between overhead lines and underground cables are not linear, and as power ratings increase, the cost of underground cables rise more than the cost of equivalent overhead lines[40]. Consequently, the cost differential between overhead lines and cables is lower for medium rather than for high-voltage transmission lines. The capital costs of underground cables at voltages up to 90 kV are estimated to be around two times more expensive than aerial lines; at voltages of 225kV the estimate is around three times more expensive, but at 400 kV the estimates are around ten times more expensive. This figure is however subject to wide variations around Europe, which in part reflects some of the technical difficulties involved in large-scale burial of lines at 400 kV. Estimates of the costs of undergrounding Europe's HV (high voltage) and EHV (extra high voltage) lines are rather speculative, as costs are site specific, but on the basis of the extrapolation of an existing estimate in France, the costs approximated €500 billion in 2003 [ICF Consulting 2003]. However, cost differentials are reducing as developments in cable technology, particularly HVDC, have been more rapid in recent years than the relatively modest incremental improvements in overhead line [EASAC 2009].

[40] The factors increasing the costs of underground power lines are: higher costs of materials (e.g. insulation), land use (land over cables must remain accessible), and higher maintenance costs. Transmission losses are lower with underground power lines.

At the same time, while costs of installation of underground power lines are higher, they are less exposed to **climatic events**, which can cause considerable **damage to overhead lines**. Underground cables also cause lower **environmental and social impacts**, which after evaluation bring down actual cost differentials with overhead cables.

Finally, the environmental impacts of **submarine cables** should not be overlooked due to the fact that these cables are crucial for the planned construction of offshore grids and for linking offshore electricity generation to the onshore network. The main environmental impacts associated with submarine power cables include **seabed disturbance**, **electromagnetic fields and thermal radiation**. Whilst risks associated with seabed disturbance during the installation phase (e.g. alteration of flora, fauna and water quality) are considered to be minimal in terms of biota [ICPC/UNEP 2009], during the operational phase permanent environmental effects may lead to a complete change in the range of organisms that live in and on the bottom of the ocean floor (i.e. the benthic community). The electromagnetic fields generated from power cables may affect the behaviour and migration of fish and marine mammals that use electric fields or the Earth's magnetic field for orientation, leading to behavioural disturbance [OSPAR 2009]. Finally, freely installed and buried cables tend to induce a temperature rise, eventually altering the living conditions for deep-dwelling cold adapted organism and biogeochemical processes more in general [Worzyk 2009].

Addressing Potential Conflicts between Renewables and Nature

Although renewable energy infrastructure affects nature in a number of ways, there seems to be a consensus that the **scale of the threat is still rather limited**. This is not least due to the fact that the penetration of renewables in the energy system is still rather low and that so far there was no need to use more **sensitive sites**. This might change in the future, as the share of renewables increases and good sites with high renewables potentials and little risks for nature and wildlife become scarce. At the same time, however, there are several **technological and political options** to reduce the scale of or solve potential conflicts.

Technical solutions include increased energy efficiency, technical amendments (often but not always at low-cost) to mitigate risks at the facility, better siting and improved ecological survey data. First, as regards **energy efficiency**, it is important to note that the renewables target is expressed as a share of the total energy demand. It follows that less renewables capacity will be required as real demand declines (either in absolute terms or in relation to demand projections). This argument, however, only holds in the medium term, as Europe's long-term decarbonisation targets will require a substantial increase in renewable power generation going far beyond what is needed until 2020.

Second, **technical improvements** to electricity generation and transport facilities can substantially reduce many risks, such as electrocution or collision. According to [Prinsen et al. 2011: 13], "electrocution mitigation can be far more controlled than collision mitigation". Electrocution is mainly a physical problem and can be avoided by changing line design or configuration (e.g. by increasing separations between lines), insulation of critical components, by applying perch management techniques (i.e. changing parts of power lines to discourage birds from sitting next to energised parts), audio and acoustic deterrents (visual deterrents have proven to be ineffective), as well as habitat modification [Prinsen et al. 2011]. Mitigation for collision is achieved either by making the power lines less of an obstacle (e.g. by removing the thin earth or shield wire) or by making lines more visible for birds (e.g. by using line markers) [Prinsen et al. 2011].

Siting of renewable power facilities is of course key in avoiding potential conflicts with habitat and wildlife. Improving spatial planning, especially for onshore wind farms, and steering developers away from most sensitive areas can avoid potential conflicts in the first place. Early spatial planning and site selection, however, require spatial analysis reliant on ecological survey data that is often not adequately available, especially for offshore areas. Overlay maps indicating high potential but low risk areas for site development are an important first step for the early strategic planning of a project. Similarly, locations of generation infrastructure should be optimised with regard to existing onshore and underwater grid connections.

Strategic planning is not only a technical issue but also a political one, as outlined in Article 6 of the Habitats Directive. However, [BirdLife Europe 2011] notes that legislation, regulations and good practices are "not always understood by all parties concerned" [BirdLife Europe 2011: 86]. In addition, one of the interviewees for this study stated that there was a general lack of capacity to apply them properly, especially in some of the new Member States. **Capacity building** is thus key and the development of Guidance Documents published by the European Commission on how best to ensure the compatibility of renewable energy developments with the provisions of the Habitat and Birds Directive are an important contribution to this. However, these documents should be made available for a broader selection of energy technologies (so far there is one available for wind energy developments, see [European Commission 2010c]) and also in different languages (the mentioned document is only available in English).

In particular, it is important that the Article 6 assessment (see above) is properly done. This is not just a financial issue, but also one related to **transparency and scientific conduct**. Proper scientific studies need to underpin public decisions on energy projects in Natura 2000 sites, which are conducted by independent parties in the framework of robust assessment methodologies. According to some of the stakeholders interviewed for this study, this does not seem to be the case for all relevant plans and projects, which might cause projects to go ahead that might otherwise be required to fulfil further requirements. On the other hand, there is also an opposite practice, according to which the relevant national authorities automatically refuse any developments on Natura 2000 sites, in the absence of any potential conflicts and thus for no apparent reason. Both cases should be avoided by basing decisions on independent, scientific assessments.

On a more general notice, EU and national institutions should increase their efforts to **raise awareness** about the Natura 2000 Network and its importance for biodiversity conservation. Above all, it is important to convey the idea that Natura 2000 sites are not excluded from economic activity, but that they are aimed at fostering economic activities while reconciling economic, environmental and social considerations.

3.4. Implementation of the Renewable Energy Directive and national support schemes

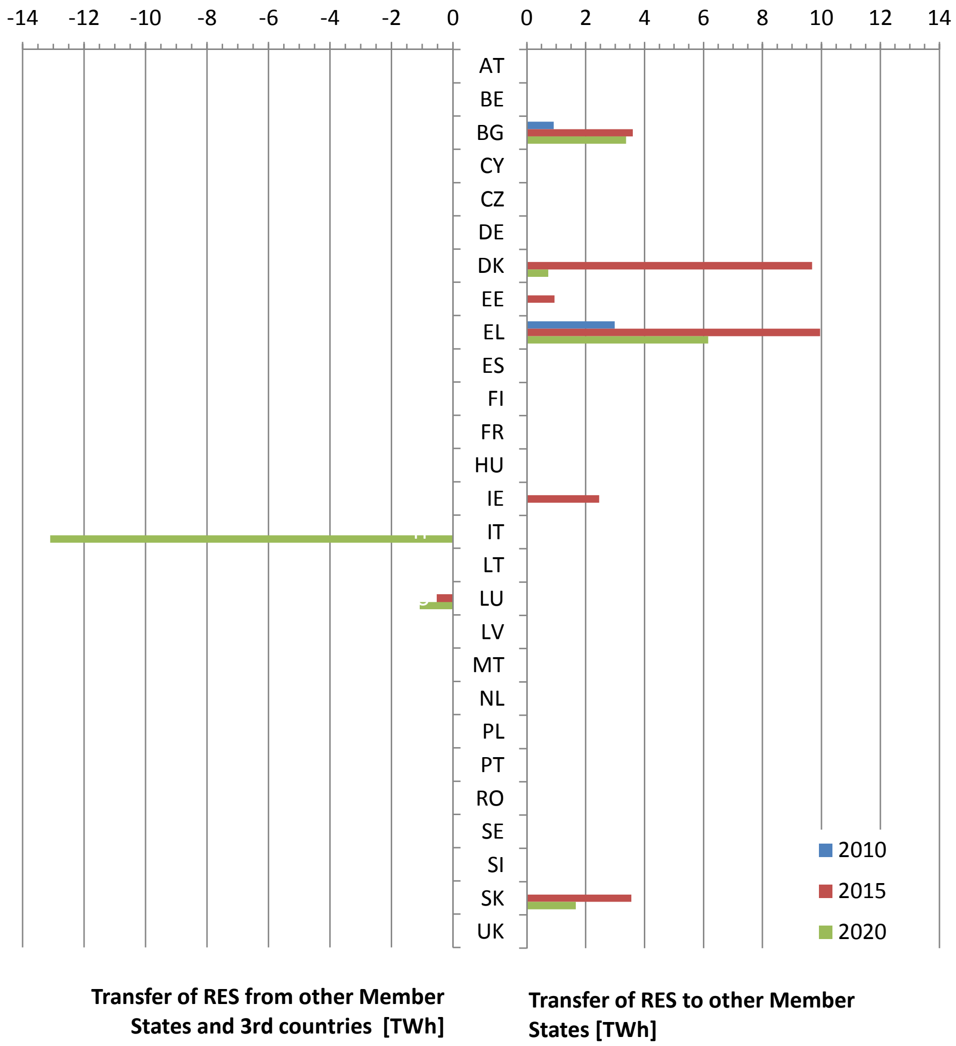
The target of reaching 20% renewable energy in the EU mix by 2020 has been set in the Renewable Energy Directive (RED), as well as the corresponding national targets. In order to increase **target flexibility** and to achieve these targets in the most **cost-effective** way, the RED promotes cooperation between MS (and also third countries) and also encourages the development of interconnectors. The basic assumption is that MS have different capacities to achieve renewable energy targets. The most cost-effective way of increasing the renewable electricity production is by increasing energy trading amongst MS and ensuring the most cost-effective and efficient production distribution. This can only be achieved if MS are properly interconnected.

More concretely, the RED (Articles 6-11) foresees the following four types of flexible mechanisms: **statistical transfers between MS, joint projects between MS, joint projects between MS and third countries, and joint support schemes**. However, a summary of the national forecasts published by the European Commission in 2010 shows that flexible mechanisms will only play a **limited role**. It finds that "only 2 Mtoe of the total renewable energy needed in 2020, will be traded between Member States or third countries" [European Commission 2010]. This amounts to **less than 1 percent**.

3.4.1. Renewable imports using RED Cooperation Mechanisms

With a view to the 2020 targets, there are a **few countries** that have stated to make use of the Cooperation Mechanisms as laid out in RED Articles 6 through 11. For example BG, DK, EL, IE and SK have stated to offer excess renewable energy to other Member States. Vice versa, Italy and Luxembourg consider imports of renewable energy from other Member States or 3rd countries. Figure 29 gives an overview of Member States' intentions according to the **National Renewable Energy Action Plans (NREAPs)**.

Figure 29: Member States intentions for transfers of renewable energy



Source: LBST based on NREAP data compilation by [ECN 2011]

There are a couple of **noteworthy points** to be highlighted in this context. Germany has stated a surplus of renewable energy that could in principle be transferred, but has not reported such in the respective "transfer" section in its NREAP. Furthermore, above transfer figures relate to renewable energy production in general. There is neither a distinction being made by renewable energy source (i.e. renewable electricity, biofuels, bioliquids) nor by energy use (i.e. as electricity, for heating and cooling, in transport). In this respect, the **NREAP reporting template** could be further refined. In the case of Italy, the transfers are indeed all RES electricity (NREAP Italy as of 30 June 2010). The following imports are considered upon completion of already planned interconnection infrastructure:

Table 10: Overview of estimated joint projects of Italy with 3rd countries

Third Country Start of imports	Third Country Start of imports	TWh from RES/year
Switzerland	*	4
Montenegro and Balkan states connected to the Montenegrin network	2016	6
Albania	2016	3
Tunisia	2018	0.6

* Italy currently imports renewable energy from the Swiss Confederation, even though this is not covered by joint projects. The amount given in the table, however, refers to the estimated maximum import amount which could be reached from 2018 onwards.

Source: [NREAP-Italy 2010]

The above sum of 13.6 TWh of imported renewable electricity corresponds to 0.85%-points of **Italy's** 17% overall RES share in 2020. Assuming an equivalent annual full load period of the import high-voltage line of 5,000 hours, this amounts to a required transmission capacity of 2.6 GW. In the case of **Luxembourg**, the amount of renewable energies is much lower compared to Italy. Furthermore, Luxembourg is situated in the middle of continental Europe with strong grid connections that – similar to other central regions – may probably anyway be enforced in order to e.g. make use of offshore wind power from the North Sea.

3.4.2. RES Directive joint projects

Article 7 of the Renewable Energy Directive also provides for MS to develop joint projects for the production of renewable energy. The requirements that define a project of common interest are not specified in the directive and it is up to the individual MS to define the specific mechanism for a project.

One obstacle to the deployment of joint projects probably is the diverse level of national support to renewable energies and the fact that the joint project mechanism might interfere with the various national schemes [Reshaping 2011]. Also, differences in legal aspects as analysed by [Fouquet Sharick 2011] are probably a barrier to joint projects.

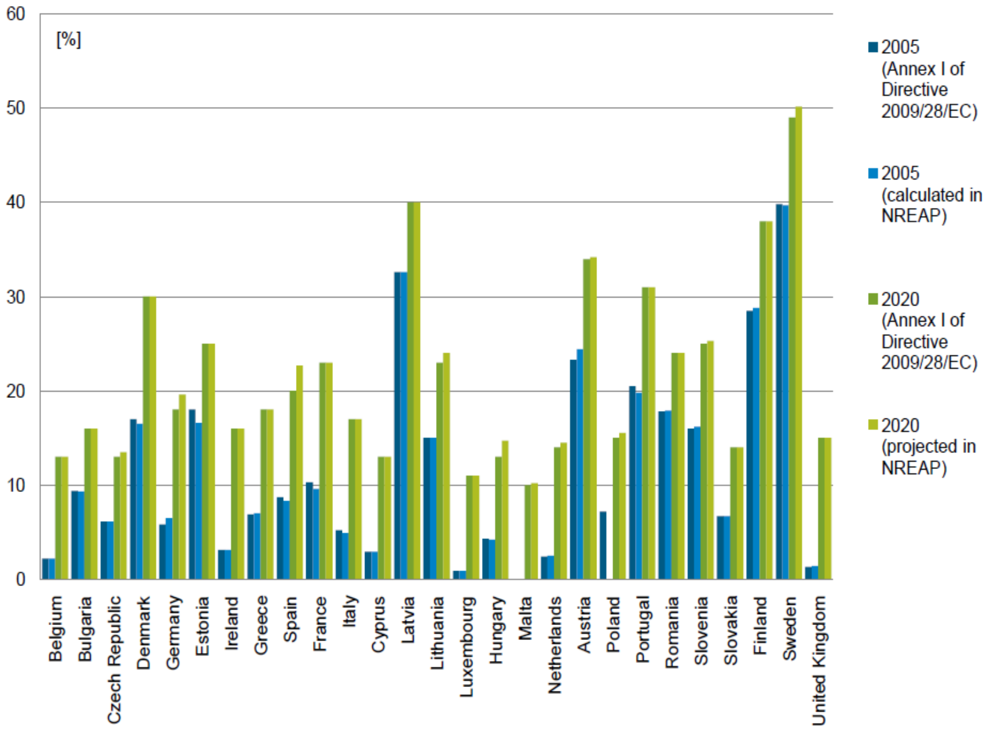
As in the case of transnational border projects referred to in chapter 4.2, it can be difficult for MS to be able to clearly define the level of cost-benefit for each partner involved, i.e. compensation for local population in the host partner and the adequate financing mechanism for the receiving partners.

3.4.3. The national strategies

The NREAPs use a set of predefined tables in which MS record the technology mix and the trajectory to reach the 2020 targets. The information submitted has been compiled and published by the European Commission [Beurskens and Hekkenberg 2011]. Given the recent submission of the NREAPs, there is to date no evaluation on the MS' performances in following up the proposed strategy.

The Summary of the **NREAPs presents a positive picture**, with the action plans generally projecting a higher level of renewables than the Annex 1 requirements of the directive.

Figure 30: Renewable energy share in EU Member States



Source: [European Commission 2011a]

According to the submitted plans, **renewable electricity** will supply 42% of the renewable energy produced (244.1 Mtoe). Growth rates in electricity from renewables are expected to reach 6 to 6.7% annually. Growth rates in specific RES-E technologies will be higher, such as for wind and solar. It is important to note that a very large share of the renewable energy will originate from traditional electricity sources, such as hydroelectric power stations.

3.4.4. Electricity from renewables: grid access and trade

Not all countries have reported on their potential to achieve their national targets by 2020. However, a summary of the NREAP forecasts (Figure 29) shows that so far only Italy and Luxembourg have declared a deficit, i.e. a potential situation where the national RES target cannot be reached with domestic RES. Given the large surplus projected in other countries (e.g. Germany, Spain, Greece, France and Sweden), potential trade flows could well be higher than suggested by the deficits of Italy and Luxembourg, but the calculations on what **share of trade** will come from renewables are not yet clear.

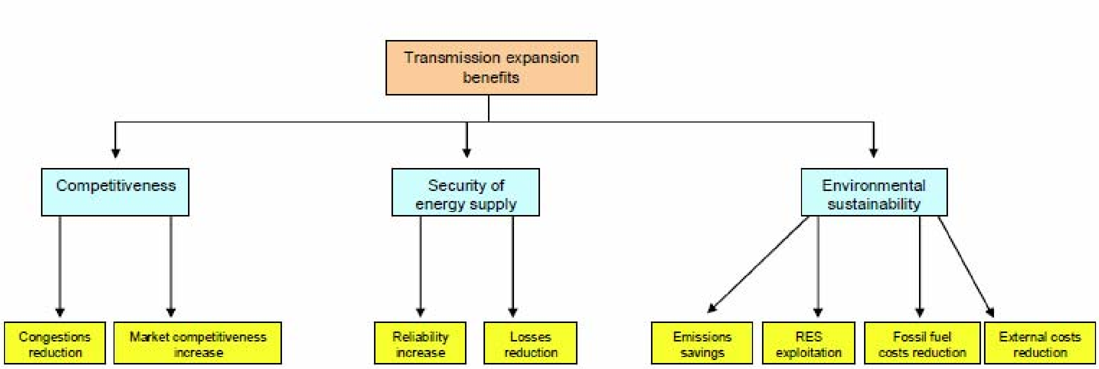
Information on **existing and planned interconnectors** is also not well recorded and needs further elaboration. This problem is reflected by the scant information offered in the plans.

The **MS have given information on grid access, purchase and transmission obligations**, but information on smart grid development, demand side management and other more precise developments are often missing. Generally, most MS declare that work is in progress to define policy tools. The action plans, while following a formal template, provide the information in very varying detail. Comparisons with the first submissions are not easy to make.

Some countries are clearly at the forefront, e.g. **Germany** already has detailed regulations on grid access, offering preferential transmission and distribution. Germany also provides a fixed feed in tariff (FiT). A number of other countries, such as the **Netherlands**, offer access to the grid, but the legislation is centred on equal access rights rather than preferential access. The Netherlands has a strong interest in interconnectors and has provided information on their development, although the share of renewables that those will carry was not declared. Spain is an interesting case, as it has strongly developed renewable electricity sources, which is triggering electricity management in the grids. **Spain** is looking to develop interconnectors with France and to develop storage capacity. There is a concern in the country that the present interconnector development plans fall short of providing the necessary transmission capacity for the potential renewable electricity production of the country. Grid access in Spain is also guaranteed in combination with a FiT.

In the discussion about potentials to trade RES-E and about the infrastructure requirements associated with an increasing share of RES in the European energy mix, it is important to note that **flexibility mechanisms cannot and should not replace grid expansion**. There are several other justifications for grid development. This means that even if the flexibility mechanisms of the RED are not used to a large extent, EU electricity grids will need to be renewed, expanded and better interconnected. Figure 31 shows the various benefits of transmission expansion, including competitiveness related to the completion of the internal market for electricity, security of energy supply and environmental sustainability. Statistical transfers and joint projects should thus not be regarded as a (potential) alternative to grid development.

Figure 31: Main transmission expansion benefits grouped according to the dimensions of EU energy policy



Source: [L'Abbate et al. 2011]

3.4.5. Coordination of support schemes

Although currently not on top of the EU energy policy agenda, EU member states will need to reconsider their national approaches to renewables support schemes with increasing interconnectedness of the EU internal electricity market. **Policy coordination (or even harmonisation)** will be beneficial for reasons of productivity, cost effectiveness, cross-border externalities or economies of scale. In a well-functioning internal European electricity market, support schemes should incentivise investments in the most cost effective locations. Currently, however, investments in renewable energy sources aim for maximum subsidies, which lead to a sub-optimal allocation of investments into less productive and more costly regions. Hence, different levels of support schemes may distort investment decisions and provide incentives for gaming. Harmonisation of the level of support would reduce incentives for gaming. There may be no need to have a uniform system across the EU for all technologies. But the same technologies should eventually fall under one support mechanism to be agreed upon by all member states. There is also a need for the creation of an EU-wide regulatory framework for support. While many aspects will remain the responsibility of the Member States, such as permitting and more generally the administration, the implementation of renewables support policy will need to be undertaken within a common EU framework. Different elements of this framework can be developed within different timeframes.

Progress towards an increasing coordination of support schemes has been made with the inclusion of the possibility to create **joint support schemes** as one of the four flexible mechanisms defined in the RED. [Jansen et al. 2010], for example, argue that if well designed, such joint support schemes may well prove to be the most cost-effective of the flexible mechanisms. They also show that entry of the Netherlands to the planned joint support scheme by Sweden and Norway (planned as of 1 January 2012) could result in welfare benefits for all participating countries "amounting to several hundreds of millions of euros per year" [ibid.]. This gives an indication of the potential benefits of EU-wide harmonisation of the currently fragmented national support schemes.

Nevertheless, harmonisation is not only related to support schemes, but also regards **technical barriers**, which need to be overcome as a priority. In an integrated energy market, technical harmonisation is necessary and desirable when it improves implementation of a renewable energy strategy. In particular, it can help in cross-border operations (e.g. off-shore wind parks). Harmonisation of technical standards (e.g. **network codes**) in transmission operations can be important to ensure easy trans-European transmission systems.

Steps in this direction have been taken with the **Third Energy Package** for the energy sector, adopted in 2009. Directive 2009/72/EC of this package focuses on the separation of production and supply from transmission networks ("unbundling"), better cross-border regulation, investment and trade, harmonisation of the powers of national regulators, greater market transparency on network operation and supply and increased solidarity among EU MS. The Third Package is in a certain sense an indirect "harmonisation" package, as it liberates the energy sector from non-market based restrictions and promotes interconnection where appropriate.

3.5. Technology development

Technology will play a decisive role in addressing environmental challenges, such as climate change and pollutant emissions. The mitigation of human impacts on the environment can ultimately only be achieved by accelerating the deployment of renewable energy sources and highly energy-efficient technologies, and through the development of new breakthrough technologies.

But the **importance of technology** goes beyond the remit of reducing our pressure on the environment. Meeting the ambitious goals of the new EU 2020 economic growth strategy will equally require the development, demonstration and deployment of green technologies at a higher rate than is currently taking place. In fact, the EU is not alone in this field. Other countries such as China, Japan, South Korea and the US are also pursuing ambitious industrial strategies in the field. For Europe to be a beneficiary in the green technology market, rather than just a consumer of technologies developed elsewhere, there is no alternative to putting **innovation** at the heart of its strategy for sustainable development in the field of the economy and ecology. A successful industrial policy in renewable energy is also essential if Europe wants to preserve its political influence in the international environmental policy arena.

However, markets in general do not invite costly or high-risk – financial or technological – innovations, such as some low-carbon technologies. A more rapid deployment of low carbon technologies at the necessary rate to achieve EU targets will therefore require an adapted framework that provides incentives for **Research, Development and Innovation** (RD&I) and **market uptake**. In reality, more efficient and low-carbon technologies are hindered by market policy failures such as the **lack of pricing of resource use** (be it extraction or emission) or the continued existence of **fossil fuel subsidies**. In fact, fossil fuels benefit from a number of consumption subsidies. The IEA (2010) has estimated consumption subsidies at $312 billion in 2009, although they reached a peak at $558 billion in 2008 when oil prices were highest[41]. In other cases, **regulatory barriers** (e.g. market structure, lack of prices reflecting the full costs, lack of access to funding) or a **lack of skills** (e.g. capacity to install, maintain and operate technology) may exist which hinder the development, demonstration and deployment of new low-carbon energy technologies. There is also an observed weak level of **patenting** in Europe (see [Aghion 2009]) compared to other advanced economies.

It is important to note that major differences exist across technologies or technology clusters, depending on the maturity of the specific technology. This will require tailor-made support in line with technological needs. For energy policy to promote new and advanced energy technologies effectively, it is vital that policy makers recognise the different requirements at each technology readiness level. There are big differences between proven technologies with potential for **commercial deployment** in a competitive environment, which may require mandates, permitting support and stable long-term measures, and proven technologies that are **not yet commercially competitive**, which require funding for demonstration and transitional incentives. These technologies require quite different policy measures. Early on in the technology development cycle, where unproven technologies still require significant research and development, R&D support is essential for underpinning science.

In more general terms, it can be said that **public intervention** is required if:

- Market and financial risks are too high for a private investor, i.e. benefits are realised beyond the period in which a private investor seeks a pay-back;
- Technology risks are too high, if large-scale and unproven technologies carry high risks of failure, for example at demonstration or early deployment level;

[41] Note that this estimate has been criticised on grounds of inadequate data and the absence of commonly agreed standards to assess subsidies [IISD 2009], which are currently being approved.

- Traditional energy technologies have an advantage over some new ones if the infrastructure for existing technologies is paid off or if regulation provides disincentives to invest ("lock-in");
- A market failure exists, i.e. the real costs to society of some existing technologies are not internalised because of subsidies or because a technology does not pay its full cost, giving existing technologies an advantage over new ones; and
- Investment in RD&I is not rewarded by the market because the technology becomes freely available before a private investor can make a profit from it, i.e. there are insufficient returns on intellectual property rights (IPRs).

The EU is addressing the environmental and technology challenges from both the demand and the supply side. At the core of the environmental and energy agenda is the **2008 Climate and Energy Package**, the **flagship legislation on renewable energy**, and most importantly the **EU Emissions Trading System (ETS)**, designed to provide market pull. Alongside these initiatives, the EU has launched the **Strategic Energy Technology (SET) Plan**, essentially to push low-carbon energy technologies.

3.5.1. The SET-Plan

The SET-Plan outline was first presented in 2006 and further developed in 2007, 2009 and 2010[42]. The technology roadmap [European Commission 2009b] presents a detailed description of the financial requirements and the areas of research until 2020. The SET-Plan was approved and officially started in 2010, although many of its elements still need to be decided.

The SET-Plan aims to build a platform of cooperation across Europe to promote collaboration between technology developers (academic and industry corporate) and the public sector on the European scale. This should result in important economies of scale, a reduction in the duplication of efforts and a leveraging of RD&I investments in the private sector. This cooperation is as important as the public financial package that should accompany it.

Within the context of the SET-Plan, a **European Industrial Initiative on the Electricity Grid (EEGI)** has been launched alongside five similar initiatives (i.e. on wind, solar, bioenergy, CCS and nuclear fission). In 2010, the EEGI proposed a 9-year European RD&D programme (2010-2018) "initiated by electricity transmission and distribution network operators to accelerate innovation and the development of the electricity networks of the future in Europe" [ENTSO-E&EDSO 2010: 2]. The aim is to identify and implement the most suitable grid architectures in order to provide for the transmission and distribution of up to 35% of electricity from renewables by 2020 and for a completely decarbonised electricity production by 2050.

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[42] EC (2006): Communication, Towards a European Strategic Energy Technology Plan, 847, Brussels, 10 January; EC (2007): Communication on a Renewable Energy Road Map, Renewable energies in the 21st century: Building a more sustainable future, 848 final, Brussels, 10 January; European Commission (2009a): Communication on Investing in the Development of Low Carbon Technologies (SET-Plan), 519 final, Brussels, 7 October; EC (2009b): A technology Roadmap, Commission Staff Working Document accompanying the Communication on Investing in the Development of Low Carbon Technologies (SET-Plan), 519 final, Brussels, 7 October; EC (2009c): R&D investment in the priority technologies of the European Strategic Energy Technology Plan, Commission Staff Working Document accompanying the Communication on Investing in the Development of Low Carbon Technologies (SET-Plan), 519 final, Brussels, 7 October; EC (2010): 2020 Communication, Europe 2020 A strategy for smart, sustainable and inclusive growth, 3 March 2010 (http://ec.europa.eu/eu2020/).

Due to the fact that a variety of different technologies and new generation components have been developed over the last 10-20 years, the RD&D programme of the EEGI focuses on **system innovation** rather than technology innovation, i.e. on the integration of innovative and developed technologies into the electricity system and on the validation of their performance. RD&D efforts concentrate on **three key areas**:

- Common network activities;
- Transmission network activities; and
- Distribution network activities.

Regarding the common network, activities of the RD&D programme focus on the increasing **interaction between transmission and distribution networks** aimed at alleviating potential negative consequences of increasing levels of distributed generation and demand management at the distribution level on the transmission level. This includes, for example, the integration of demand side management in TSO operations. **Transmission network activities** are organised around planning, investment, operations and power market issues. Examples of concrete actions in the area relevant to this study include demonstration of renewable integration and power technologies for new architectures and for more network flexibility. On the **distribution level**, the RD&D programme concentrates on the integration of smart customers, of smart metering, of distributed energy resources and new uses (including the integration of storage in network management), and on a smart distribution network. The cost of all the activities proposed under the EEGI is estimated at just below €2 billion until 2018, excluding costs of EU-wide deployment of the solutions. The bulk of the finance will be needed for activities on the distribution level (€1.2 billion) and on demonstration of technologies in all three areas (€1.4 billion) [ENTSO-E and EDSO 2010].

Financial requirements for RD&D within the six European Industrial Initiatives are estimated at around €50-60 billion for the period 2010-2020 [European Commission 2009]. There is thus an evident need to increase the level of R&D investment in Europe, including from the public sector and the EU budget. The fact that public budgeted resources at EU and Member State level are scarce will require greater use of the EU **financial engineering instruments**. This is most important in the so-called **"bridge financing"** areas, to prevent technologies with a high European added value and positive long-term economic rates of return from dying off in the early stages of development due to market and financial risks and the generally long lead time to commercial deployment. The EU can provide financial support through tailored **combinations of grants and loans**. The EU has already successfully established the Risk-Sharing Financial Facility (RSFF) in the area of RD&I to provide debt financing for loans to RD&I demonstration and deployment projects. This instrument can be a model for energy specific RD&I investments.

The SET-Plan does not operate in a vacuum and it is important that the technologies developed for the future encounter the right market and infrastructure conditions for their deployment. At the same time, policy at EU and national levels coherent with SET-Plan priorities will need to provide additional leverage to SET-Plan technologies. Key areas include **regional policy, state aid policy and especially public procurement**, which is an underexploited tool to boost the deployment of low-carbon technologies.

3.5.2. Policy Recommendations

Policy makers need to address at least **two types of barriers** relevant to RD&D of a smarter electricity grid, able to cope with the challenges posed by environmental and resources concerns. **Firstly**, RD&D organisation barriers need to be addressed, including the fragmentation of efforts across-borders.

This requires a higher degree of technical and research coordination. **Secondly**, market failures and distortions need to be addressed. As regards the latter, it should be noted that while investments in smart grids have to be made largely by network operators, it is often other stakeholders that benefit from them. Costs and benefits of the investments are thus asymmetrically distributed. In addition, current **tariff schemes** do not provide sufficient incentives to support large-scale RD&D projects. Although the Third Energy Package foresees better support of research by tariffs, **support from public resources** (both on the EU and Member State levels) will be required in the transition phase [ENTSO-E&EDSO 2010]. According to the Third Package, tariffs should ensure that network operators are granted appropriate incentives, including support to related research activities (Directive 2009/72/EC, Art. 37-8). However, new appropriate tariff schemes are still lacking in a majority of MS and are not expected to be in place before 2013 [Gonzalez 2010]. Leveraging more European sources of funding would be beneficial both to promote research that takes a truly European perspective and to bridge the time necessary to properly implement the relevant provision of the Third Energy Package. A recent Task Force convened by the Centre for European Policy Studies (CEPS) in Brussels [Núñez-Ferrer 2011] developed a set of concrete recommendations aimed at policy makers in order to create the right framework conditions in terms of governance, finance needs, (new) sources of finance and the positive impact that consistency and coherence of other EU policies with SET-Plan objectives can bring about. What follows is a list of these **policy recommendations**.

- The SET-Plan policy must ensure the right **economic and regulatory framework conditions** to foster low-carbon technology development, demonstration and deployment. These must include:
  - A truly **integrated and competitive energy market**, including the necessary cross-border infrastructure and appropriate regulation; and
  - Energy **prices** that adequately reflect the costs of security of energy supply, climate change, the environment or other social impacts;
- In parallel, the EU and Member States must support the technology by **addressing specific non-market barriers** to RD&D, demonstration and deployment;
- Those involved in governing the SET-Plan, namely the European Commission, MS and industry, must go beyond declarations of intent and **accept responsibility** to drive forward low-carbon technology development, demonstration and deployment at EU level and provide for financing (commit and deliver);
- European support should **lead in areas with important cross-border or scale effects**, notably with those technology options that are required in the long term but need preparation today because of long lead times, e.g. (stronger and smarter) grids, zero-emission powertrain technologies (battery, fuel cell) and fuelling infrastructure (distribution grid, hydrogen fuelling stations), and stationary energy storage;
- For all SET-Plan technologies, European support should help facilitate MS efforts to **ensure compatibility, avoid duplication, spread best-practice across the EU** and ensure inclusion of all MS and regions;
- The EU must ensure a **higher level of financial intervention, including a higher EU budget allocation**. This must include:
  - Higher levels of **grant funding** for basic research and early stages of demonstration, and especially:

  - **"Bridge financing"** to cover technological, market and financial risk in the demonstration and early deployment phase;

- In particular, the EU should envisage setting up appropriate **risk-sharing instruments** building on the success of the Risk Sharing Finance Facility (RSFF), perhaps based on a Portfolio First Loss Piece approach to ease the provision of (bridge) financing to facilitate the market deployment of unexploited new technologies;
- European support for SET-Plan technologies should also:
  - Promote the idea that the **Cohesion and Structural Funds** are used to finance infrastructures which are appropriate for SET-Plan technologies;
  - Bring **EU procurement rules** in line with the EU objectives to promote new low-carbon energy technologies and energy efficiency;
  - Align **EU state aid rules** to allow MS to support national investments in energy RD&I to the same tune as is the case for EU projects. This should especially be so when national investments have an important European added value (based on Article 107 3(b) of the Treaty);
  - Include a review and reform of **financial and control rules** for initiatives in the area of RD&I, such as for the EU Research Framework Programme in line with recommendations of the Carvalho Report of the European Parliament, with a particular focus on bureaucracy; and
  - Address the issue of **IPR** rules to give proper incentives for industry and SMEs to participate to EU research programmes.

Furthermore, existing **EU budgets should be more strongly aligned to sustainability**, thus freeing money from unsustainable investment activities for support of green technology development and deployment. For example, a study commissioned by the European Parliament [WI 2011] assessed the sustainability of EU budget items in energy. The study concluded that even though the EU energy expenditure appears to generally perform well, about one quarter of the energy budget is controversial in terms of sustainability. It is worthwhile noting that **Structural and Cohesion Funds** constitute more than half of the total energy related EU budget, underpinning the importance of these funds at European level. Around 10% of these funds were invested in unsustainable traditional energy sources.

3.6. Financing

3.6.1. EU budget support to grid development

For the development of the grid, two main policies can have a decisive impact in the Multiannual Financial Framework Proposals for 2014-2020 [European Commission 2011c]: the **Connecting Europe Facility** and the **Cohesion Funds**. The Connecting Europe Facility is a continuation of the Trans-European Networks budget for energy transport and digital networks in non-cohesion countries, with a now larger budget of €40 billion. Its central focus is on cross-border multi-country infrastructure. The Cohesion Funds will complement the facility in the cohesion countries: €10 billion from the Cohesion Funds have been put aside for the Trans-European infrastructures. For the electricity grid, the focus is on the interconnectors and main transmission lines favouring electricity trade.

Of the €40 billion in the Connecting Europe Facility, €9.1 billion have been earmarked for energy infrastructure investments, which also include electricity transmission and interconnectors (and other energy infrastructure). The Commission has identified four priority electricity corridors.

The **Connecting Europe Facility** will link its resources to financial instruments in order to expand leverage, such as the use of guarantees through the EIB. It will also allow for co-financing rates to reach 30%[43], higher than the present 10% in the TEN-T, which is considered too low to attract interest from the private sector. The Cohesion Funds have higher co-financing rates, up to 85%. In the financial instruments, a new important proposal is the Project Bonds Initiative (PBI), which allows to cover larger financial needs for infrastructures with a large private sector investment. This new initiative is described in section 3.6.2.

In addition to the Connecting Europe Facility and the Cohesion Funds, **Structural Funds** will play a role in the energy infrastructure, not only in investments for production of renewable electricity, but also in the development of local grids such as smart grids. The allocation of funds for electricity grids in the Structural Funds will largely depend on national strategies, which are yet to be produced. For the 2007-2013 programming period, investments in renewable energy have been a very small part of the use of the Cohesion Policy (Cohesion Funds and Structural Funds), i.e. around €5 billion or approximately 0,5% of the funds [Núñez Ferrer et al. 2009]. Transmission and grids were not a priority investment and few funds have been used for grid infrastructure, and with a focus on electrification rather than renewable energy. This is bound to change in the next programming period, with the final use of funds on renewable electricity, smart grids and transmission determined by the forthcoming regulations and the national strategies of the Member States.

In addition, funding for the **SET-Plan** from the research and development budget of the EU can assist in the development and deployment of new renewable technologies and new grid technologies, such as smart grids. The funds can also be combined with the Structural Funds at the final demonstration and deployment stages [Núñez Ferrer et al. 2009; Núñez Ferrer et al. 2011].

3.6.2. Private finance

Considering the increasing need for infrastructure development projects in the coming years, action needs to be taken in order to enhance the level of private investment within the overall level of investment in infrastructure. In this section, we will present a few examples from the current literature.

In order to reduce the high level of uncertainty for investors, it will be necessary to promote the **harmonisation and simplification of regulatory standards** at the European level, which will ease the process of comparison among countries.

[43] In case a project is not commercially viable but aims at increasing security of supply or ending isolation of some Member States, the required rate of co-financing could even be higher (up to 80%) [European Commission, 2011: p.10].

This will reduce the uncertainties of investors, especially with regard to the issue of permitting procedures and the related risks (see chapter 4). In practical terms, policy makers should attempt to introduce a system with **"priority premiums"**: stakeholders would then be entitled to a higher return rate for those projects that better serve the scope of the main pillars of the EU energy policies, such as market integration and security of supply [Roland Berger 2011]. [Roland Berger 2011] suggests the implementation of a clear and transparent mechanism, in which the EC would be responsible for the selection of the **eligible projects**. They also propose that the costs of the premiums scheme should be equally shared between the European institutions and the Member States.

Again with reference to the obstacles presented in chapter 4 and concerning the difficulties encountered by TSOs when it comes to the emission of private equities, the regulatory regimes would have to be modified in such a way to speed up the unbundling process and the privatization of publicly owned TSOs. Since it is unconceivable to deliver these results in one step, it will be necessary to have in place publicly owned systems of financing coordinated at the European level, such as **public grants and institutional structures**.

Public grants are the most common tool used at European level to help TSOs under financial strains to develop projects of European interests [Roland Berger 2010]. The co-financing system currently in place also gives to the EU institutions a consistent leverage on the project type; this system is, however, very expensive and therefore not applicable to all future projects, since it would probably turn out to be unsustainable [Roland Berger 2010].

The largest type of **institutional structure** in the EU is the recently established **"European Fund for Energy, Climate Change and Infrastructure"**, commonly known as the **"Marguerite Fund"**. Its core focus sectors are Energy and Transport infrastructure development; the role of the fund is to promote private investments within these sectors while also fostering the EU goals with respect to the EU 2020 policies. The Fund targets green infrastructure projects, without taking any majority part in them, while promoting the interaction among private and public investors. The Marguerite Fund serves as a good example for future applications of EU infrastructure development investment; however, it should only be a "temporary solution" in the transition towards a more direct involvement of private investors [Roland Berger 2011].

The final outcome of this practice should be the creation of a **European Transmission Infrastructure Fund (TIF)**, solely focused on projects of interest in the energy infrastructure sector. The funding system should also provide incentives more similar to those of the current corporate approach, i.e. directly investing in TSOs and providing extra-funding for future programmes. It should also have a long-term perspective of minimum 25 years, a characteristic that would well match the requirements of pension funds as will be seen in chapter 4.4. Even if the EU shapes the scope of such funds, its direct contribution should be smaller than in the Marguerite Fund, and the majority of investment should be acquired by private agents.

In addition, a platform for interaction between financers and industrial stakeholders should be created in order to allow for a constant dialogue on the need and capacities of each party [Roadmap 2050].

Special Focus: EU Project Bonds

One instrument that could potentially be of use for the grid development, in particular in relation to the planned Connecting Europe Facility of the Multiannual Financial Perspectives covering Trans-European grid development and interconnectors, is the **Project Bonds Initiative (PBI)**[44]. This initiative was tabled by the European Commission in the context of its infrastructure package[45] on 19 October 2011.

The PBI has the objective to cover the decline of long-term infrastructure finance from the traditional investors and banks by attracting funds from investment funds, such as pension funds. The PBI is a credit enhancement mechanism like other EIB instruments currently in place, with the objective of reducing risks and raising the credit rating of projects to levels attractive to those funds. There is a large misunderstanding on the nature of the "project bonds", and some apparent lack of clarity as to what they should be. In principle, project bonds are similar to the **Loan Guarantee for TEN-T projects (LGTT)**, which offers a guarantee to attract equity from project promoters. However, many projects require levels of funding beyond those offered by such schemes. The LGTT also suffered from the difficulty to negotiate loans with several financial institutions, making it impractical for raising the large funding required for the infrastructures of the Connecting Europe Facility (CEF). Given the nature of the PBI, it is an option only for single large projects with costs over €250 million, with a bond share of approximately €200 million. While still having an element of pure equity as own funds and pure loans from project companies, the Initiative also adds project bonds, which the companies issue for investors to acquire. The EU/EIB intervention increases the rating of the senior debt, which then can be issued as a bond.

Following an EIB understanding[46], the possible design of the project bonds would be based on the idea of **"tranching"** (i.e. dividing) an issuers debt **into layers of different seniority**. This means that the debt is divided into groups of different debts with their own risks and returns, seeking different kinds of investors.

After the setting up of a project company, i.e. a special purpose vehicle for an infrastructure, the finance can be divided into:

a) A **senior tranche** issued as bonds to institutional investors such as insurance companies and pension funds; the bonds are issued by the project company.
b) A **subordinated tranche** underwritten by the European Commission and the EIB as a funded loan or a simple guarantee.

The concept of part b) is similar to the system in place for the LGTT of RSFF and helps to reduce risks by borrowing costs for projects, and to ultimately attract investors and also buyers of the bonds.

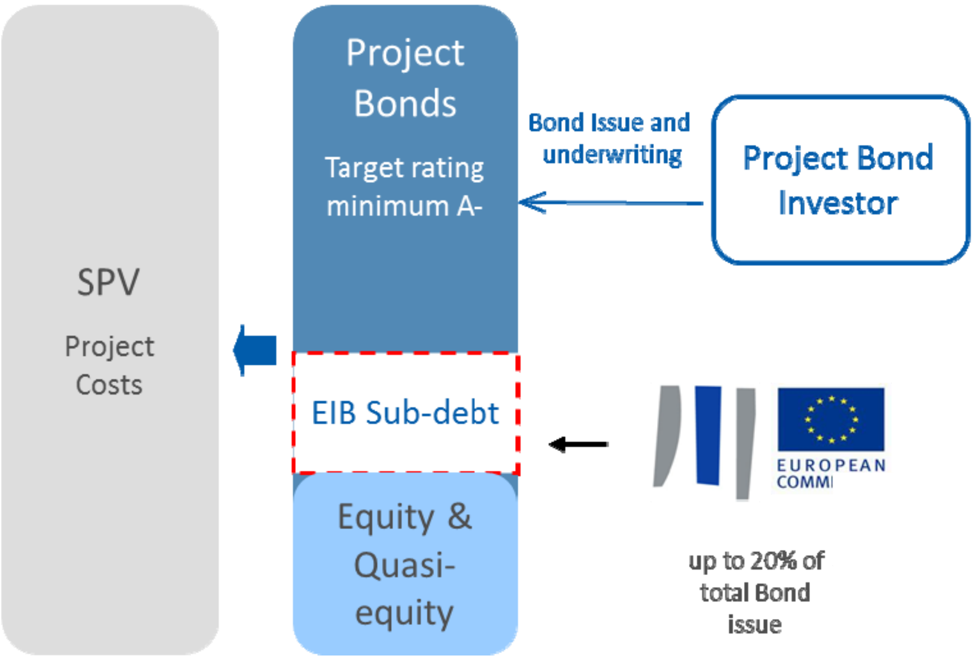
In a nutshell, the large projects would end up with three components (Figure 32) the guarantee (EIB Sub-debt), loans from the EIB and other financers (equity and quasi-equity) similar to the RSFF and LGTT, and finally projects bonds, which is the novelty factor.

44 European Commission (2011), A pilot for the Europe 2020 Project Bond Initiative, COM(2011) 660 final.

45 European Commission (2011), Communication from the Commission – A growth package for integrated European infrastructures, COM(2011) 676.

46 European Investment Bank (2011), 'Supporting the EU budget: the EIB contribution', presentation at the CEPS Task Force meeting, power point presentation, version of 22 June 2011.

Figure 32: Subordinated Project Bonds Instruments



Source: [EIB 2011]

Risk is then divided, as is the case with RSFF and LGTT, in tranches, with the EU budget taking up the **First Loss Portfolio Guarantee (FLPG)**. The EIB would de facto be at the second loss position, leaving further residual risks to other investors and bond holders. The exact design of the system is not fixed yet, and the risk level of and scope of the project bond scheme can be further altered by the joining of other institutions such as the KfW in providing low interest funding.

It is important for policy makers to understand that **project bonds are another debt based instrument** which ultimately needs to be repaid and can thus only be used for projects with high value added and sound economic rates of return. **Additional grant support** for specific projects could also be envisaged when high value social returns cannot be captured by the projects. In transport and energy, however, there are a number of instruments to ensure that the value is recovered.

The EU budget would offer a guarantee of a maximum 10% of the project cost and the EIB an equivalent amount: 80% of the risk is thus taken up by the private sector. The PBI represents a useful addition to the financing instruments.

To conclude, the PBI is an important element to finance the large infrastructure needs of the EU, and should be supported. The limited liability of the EU with a maximum 20% risk share (EU budget and EIB) ensures that projects will be assessed for quality by the private sector, avoiding non-viable projects to be financed. However, the PBI is a measure specifically designed for **bankable large infrastructure projects** and is not a solution for other needs. Primarily, it can only help in large single projects for infrastructure and would not be functional in many different areas of investment. The target investors, such as pension funds, are risk averse and would not buy in for projects which are high risk or small in size (under €200 million).

4. Obstacles to grid roll-out

KEY FINDINGS

- **Technical barriers** are not perceived as insurmountable, in particular because stakeholders have acquired experience on a case-by-case basis and important "knowledge-sharing" among the interested countries has also taken place. The variability of renewable energy production makes the accurate prediction of renewable production difficult for network management. PV integration poses problems particularly at the distribution level.
- **Economic obstacles** are more pressing, particularly in relation to the application of the Third Energy Package and electricity market integration. The European electricity market is still dominated by a small number of large producers, reminiscence of a collection of monopolies, where competition is hindered by disincentives to further invest into interconnections. In the same way, cross-border disputes on infrastructure projects arise from the incapacity of stakeholders to appropriately allocate costs and benefits of a determinate project. Equally important is the fact that some DSOs are de facto unable to recover the costs of new investment because of national regulatory systems, which discourages them to invest in smart energy technology.
- **Lack of public acceptance** is considered by many as one of the most important obstacles to the deployment of energy infrastructures, notably with regard to grid roll-out of overhead lines. There are several issues at the heart of the public opinion, which vary in importance depending on the project location, extension and proximity to populated areas: environmental issues, health risks related to the exposure to electromagnetic fields, and the negative visual impact on landscape, which also affects landowners' property value.
- Amid the **administrative obstacles**, various issues are pressing, starting with the uneasiness of transmission system operators (TSOs) dealing with an inhomogeneous European regulatory framework as well as most importantly long and difficult permitting procedures at the national level. The lack of a harmonised system of Network Codes is also felt as an important drawback by stakeholders. Finally, the current system of connection charges and permitting procedures discourages the intake of new ventures for renewable energy producers.
- With the launch of the **Energy Infrastructure Package (EIP)**, the European Institutions attempt to better influence energy infrastructure development in Europe in order to foster renewable electricity integration. Close collaboration between European and national institutions will be required in order to ensure a democratic and acceptable process. The way in which legislation is implemented by the Member States will ultimately define the future of European energy infrastructure.

In chapter 2, the main options for the integration of variable renewable energies were presented, including reinforcement and upgrade of the electricity grid, storage and demand side management. This chapter will outline the major obstacles to the development of a European energy infrastructure to incorporate a large amount of renewable energy sources. It describes **obstacles of technical, economic, social and administrative nature** that can be faced by the main stakeholders when attempting to promote grid related infrastructure projects.

Technical barriers are dealt with first, since if these were found to be unattainable, no further investigation would be required; however, the result of this enquiry shows that they do not represent major obstacles to the deployment of energy network infrastructure. On the other hand, economic barriers, social acceptance and administrative procedures are all considered as **important obstacles** for the development of energy infrastructure projects. For each of these, high levels of political willingness will be needed in order to set necessary common European-wide regulations and standards. Although economic barriers are probably the most important ones, it is in general not very useful to attempt to establish a ranking of relevance for all the obstacles, since this will vary considerably on a case by case basis. The material presented is based on a series of short interviews with main stakeholders and extensive literature review.

4.1. Technical

This sub-chapter looks into the technical challenges characterising the integration **of RES** into the current energy system. In particular, the specific issues at high voltage level for **wind energy** and low voltage level for **solar energy** will be described. Issues regarding **energy storage** will be covered as well, to conclude with a best practice case study of the Centre for Control of Renewable Energies in Spain.

4.1.1. RES integration in the grid

Technical obstacles are strictly inherent to the **intermittent nature** of the main sources of RES and the applied system management, which is currently unable to cope with the integration of high levels of variable RES-E into the European grid. The intermittent nature of RES is explained in detail in chapter 2.

In principle, technical issues exist because the overall network was designed for power to flow only in one direction, starting from the **central power stations** reaching the individual users, rather than the other way around as is the case with decentralised RES generation. This is exacerbated by the fact that renewable energy plants, such as wind farms, are often located in **remote regions** not well-served by grid-connections being far away from the main centres of consumption [DG-GRID 2007].

According to ENTSO-E, the **major technical issues** when attempting to deploy grid development and update the existing infrastructures are mostly affecting TSOs in charge of the high voltage (HV) grid [TYNDP 2010] and are related to generation variability:

- Inability to anticipate future power requirement and production, which makes it impossible for TSOs to develop a generation plan;
- Increasing complexity of grid operation and therefore of grid planning.

At the HV level, among the **most pressing issues** we can also find [DG-GRID 2007]:

- Voltage management;
- Thermal rating issues;
- System fault issues.

The **construction of new HV lines**, although necessary, is not the only solution for RES integration. Findings in the recently published "Susplan" research project demonstrate that the construction of new lines can partly be avoided by **refurbishing the existing one(s)**, for instance with new cabling systems with low sag conductors and real time monitors of cable temperatures that help increase the flow limit on the conductors, thus avoiding congestion [Susplan 2011].

New technologies, such as **phase shifting transformers** and **flexible AC transmission systems (FACTS)**, will also increase power control over the grid and therefore reduce the risks of grid failure [Susplan 2011] (see chapter 2 for more details).

At the **lower voltage** management, DSOs also face important technical challenges in relation to the integration of RES-E, for instance with electricity produced by solar energy applications as described in the "Solar" section hereunder.

In the **Czech Republic** for instance, the steady increase in the amount of RES installation, particularly solar energy, has induced the National TSO to declare a moratorium on new permits because a high amount of renewables seriously undermines grid stability [Eclareon 2011].

4.1.2. Wind

Chapter 1 explained that wind energy is foreseen as one of the leading renewable resources in Europe. Today, wind energy already reaches **high levels of penetration** in certain European countries such as Denmark, where it can achieve a daily penetration of almost 100%, or Ireland (40%) [EWEA 2010].

Although technical obstacles are no major concern with respect to the integration of onshore wind farms, they can still be found when dealing with the integration of electricity produced by **offshore** plants [EWEA 2010].

Planning new lines to connect offshore wind farms to the onshore grid can be complicated because of the limitations of AC connections. Because of cable capacity, in HVAC connections the cables need to carry the charging current along with the useful load current, which leads to heavy losses in the load capacity of the cable itself, particularly for long distance bulk power transmission [ESS 2004]. This is the reason why **underground HVDC** is the preferred technology. HVDC can also be run underground next to AC grids, preventing the need to reinforce the grid onshore [EWEA 2010a]. New technologies are still being developed, such as HVDC Voltage Source Converters (HVDC VSC) or HVDC switches, which present specific characteristics apt to the deployment of offshore grids [EWEA 2010]:

- Compact converter stations suitable for offshore platforms;
- The technology permits active and reactive power to be controlled independently, and therefore allows connecting it to the onshore grid providing **black start capability**, which facilitates recovery in case of faults.

The variability of wind energy production influences the daily system management of the electricity network, whereby short-term variability has a much stronger impact than the long-term one. The latter is predictable and affects only the long term planning of network development. Geographical spread of wind farm installations belonging to the same grid is an important factor that helps reducing short-term variability, especially within the hour [EWEA 2010].

Variability issues could therefore to a large extent be alleviated through the reform and **integration of the European electricity market** and the **harmonisation of Network Codes**. See "Economic Obstacles" and "Administrative Obstacles" hereunder.

Findings from an analysis of variability influences are summarized in Table 11.

Table 11: Wind energy variability, main impacts

Timescale	Forecasting capacity	Impact on daily management	Impact on the system
Second to minute	Low	Not noticeable	-
Within an hour	Low	Disruptive (within small geographic spread)	Influence balance capacity
Hourly	High	Partly disruptive	Predicted forecast error leads to balancing needs
Monthly / seasonal / inter-annual	High	Not disruptive	Affect long term power system planning

Source: [EWEA 2010a]

To conclude, it is important to realise that thanks to an already large deployment of wind energy in certain MS, stakeholders **have acquired experience by resolving many technical issues on a case-by-case basis, and that important "knowledge-sharing" among interested countries continues to take place** [ENS Interview].

4.1.3. Solar

Photovoltaic (PV) electricity in Europe is currently a highly decentralized energy source. Whilst wind farms can reach up to 300 MW, PV installations rarely exceed 1 MW. In Germany, 85% of all applications are connected at low voltage (230/400 V), 15% at medium (10/30 kV) and the percentage of high voltage is negligible [Engel 2011], although increasing. The integration of PV electricity is generally an issue to be dealt with at the distribution level (low voltage) rather than the transmission level. Therefore, PV integration is from this perspective generally less of a threat to grid stability than wind.

PV systems are usually directly connected to the grid [EPIA 2011a], and in most European countries a **feed-in-tariff (FiT)** system is in place, where the owner of a PV installation receives a fixed tariff for any amount of electricity that he feeds into the grid. In this setting, the owners of PV installations are incentivised to maximise their PV electricity production regardless of their own electricity consumption.

The variable characteristics of PV installations in Europe need to be managed at the **system level of the DSOs**, just as wind installations need to be managed by the TSOs. To mitigate this, different technical options are being looked at, including storage and technology improvement that would allow for higher consumption at or next to the production facilities.

The full deployment of **"smart grids"** and operational DSM are in this respect also very important for the future PV market. The term **"prosumer"**, a combination of the words "producer" and "consumer", has come to define precisely those agents that within the energy system will be increasingly able to monitor at each stage their energy production and consumption in a precise manner, and to actively participate in the running of the system.

Incentive schemes will thus need to reflect this ability and amount limit for feeding-in of PV electricity into the grid. The **social challenge** that this implies in terms of "mentality change" for consumers as we know them now will be looked at in more detail under the heading "Social Acceptance".

4.1.4. Grid-scale energy storage

Chapter 2 presented a detailed analysis of the options available with respect to the use of energy storage to improve balancing capacity of intermittent renewable production.

Today, **large-scale** and **small-scale storage capacities** of electricity are needed and used in the current operation of the European energy infrastructures. Including more RES-E into the overall European system will eventually increase the need for storage and therefore further research, development and demonstrations need to be performed to successfully optimise and integrate all current and future technologies.

Agreement among stakeholders concerning the **needs for energy storage** in the years to come varies greatly, depending on their time horizon and whether they have a system perspective. The Grid Report from EWEA states that "*For the penetration levels expected up to 2020 there is no economic justification in building alternative large scale storage, although additional storage capacity might be required after 2020";* rather than from technical concerns, though, opposition seems to stem from financial considerations [EWEA 2010a]. Contrarily to the wind sector, in the PV sector storage is considered as one of the solutions to be applied in the future in order to help load balancing and store energy in off-grid applications.

Due to the observed complementary nature of solar (from the Mediterranean countries) and wind power (from the North Sea) across Europe, RES-E producers focus primarily on interconnection capacities of the grid rather than storage, which would be used only for minor corrections.

[Schill and Kemfert 2010] have analysed the impact of the pumped hydro reserve onto electricity generation in Germany. The authors investigate the interaction among the biggest market players (E.ON, RWE, Vattenfall and EnBW), and compare the result between strategic and non-strategic models. Their findings support the hypothesis that storage has a positive effect on overall welfare, since it smoothes market prices by substantially reducing peak load pricing and slightly increasing off peak prices. The welfare gain derives from an overall decrease in market prices and producer rents, coupled with an increase in consumer rent. It is therefore interesting to note that, **if market players behave strategically, it is in their individual interests to underutilize storage capacities.**

In order to promote future RES-E integration through storage capacities and to ensure the deployment of smart grids, it will be necessary to ensure through regulation that storage facilities are not in the hand of one large producer, but equally shared among all players [Schill and Kemfert 2011].

CASE STUDY: The Control Centre of Renewable Energy in Spain
Timely exchange of information on production and consumption loads is essential for an effective integration of RES. An excellent example is the Control Centre of Renewable Energy (CECRE), which is the first European power control centre specialised in the management and control of renewable energy. Established in Spain in 2006, it has allowed the country to be the first to establish full control over all its wind farms above 10 MW [REE 2009]. All authorised producers are directly connected to the CECRE, while measurements of reactive and active power, connectivity and temperature are downloaded from the wind farms every 12 seconds [REE 2009]. This system allows the network operator to predict the wind energy production within the hour and with a very good degree of certainty. This information is then sent to all energy producers, who can adjust their power load to the grid [REE 2009]. Altogether, there are 23 such centres across Spain.

4.2. Economic barriers

The economic obstacles to the development of a European electricity grid are closely associated with the regulatory frameworks and the current **architectures of the European electricity markets**. This section analyses the main market distortions, cross-border issues in the European electricity markets, unfair competition and disincentives to invest into further interconnections. The chapter also looks into the financing obstacles faced by DSOs and TSOs in finding adequate sources of financing for energy infrastructure projects. The economic barriers are estimated to be **severe obstacles** to infrastructure development in the EU. A number of cases of market failure will need to be addressed by the regulators in order to achieve the necessary conditions for success.

4.2.1. Market distortions in the European electricity market

Despite on-going efforts, the European electricity market still suffers from significant market distortions.

At present, most European markets work on a system of long-term/medium-term energy sales and only in very few circumstances it is possible to modify the flow of energy from one market to the other within a day. Moreover, stakeholders often have limited information about the transaction prices of neighbouring countries, and even if willing to increase trade, TSOs are unable to do so due to **limited grid interconnections**. The solution to this problem should be further market integration and the establishment across all Europe of **intra-day market systems** [EWEA 2010]. The design of a proper market model should provide TSOs with better incentives to improve grid connection and deploy interconnection projects.

Network operators and utilities are actually likely to oppose further integration of the electricity market, since this implies **enhanced competition** in a system which has been run for years as a monopoly [Frontier Economics 2008]. Electricity producers are unwilling to support the deployment of further interconnections, as this will reduce their monopoly and allow electricity to flow freely, thus lowering prices, particularly in the high price markets.

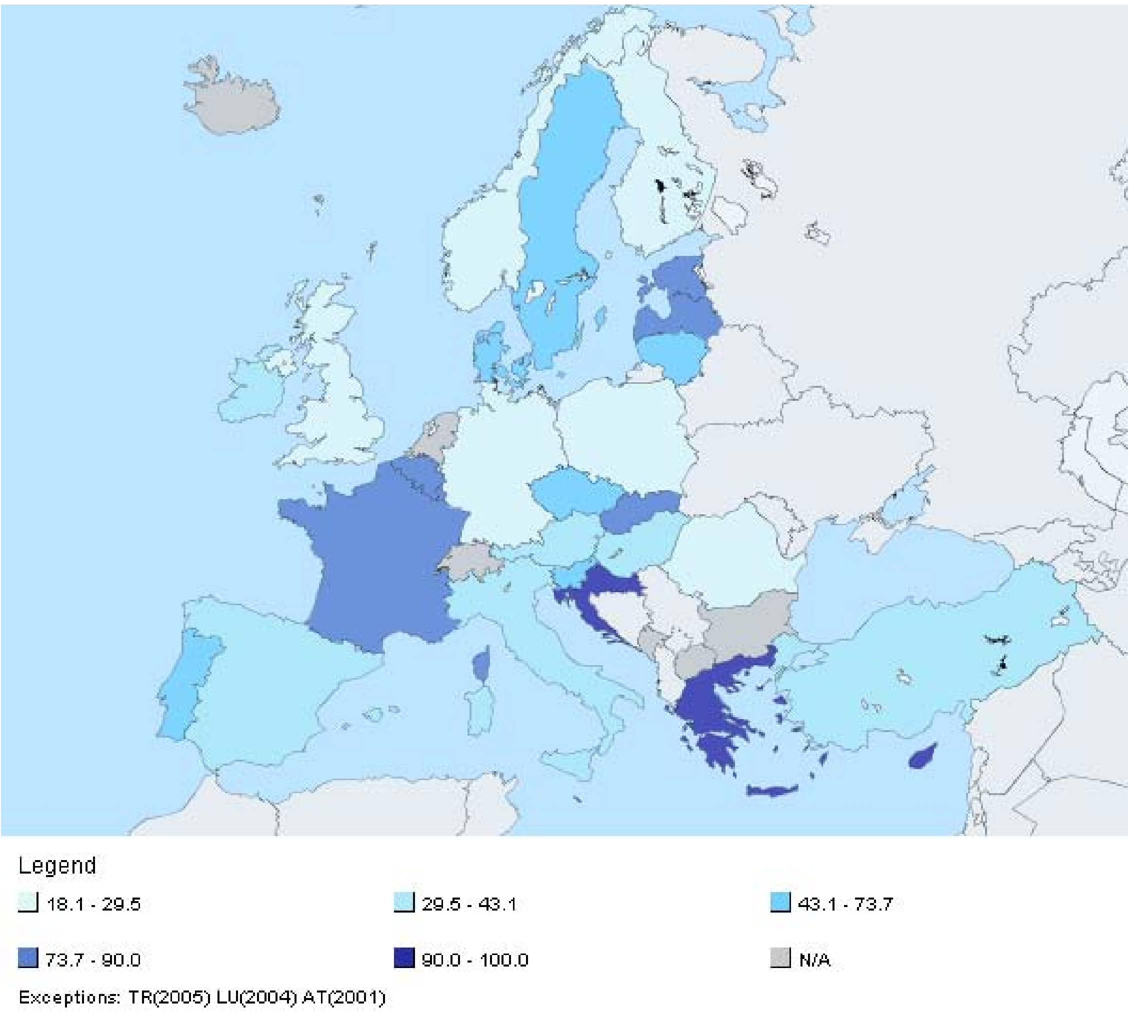
The construction of new interconnectors is however fundamental to promote Integration of Electricity Markets (IEM) and reduce the risk of congestion on the borders. Congestion between electricity markets is likely to happen if the demand for electricity is higher than the grid capacity. Regarding congestion, TSOs are allowed to acquire **congestion income** on cross-border exchanges, which is an additional incentive to oppose further integration.

The example of the **NorNed interconnector between Norway and the Netherlands** illustrates how all stakeholders can benefit from further interconnectors, if the electricity markets present complementary characteristics [Kapff and Pelckmans 2010]. In this case, Norway electricity demand is stable and hydro power predominates in the energy mix. On the opposite side in the Netherlands, electricity demand is variable while the energy mix is dominated by fossil fuels which provide stable production but are very expensive to adapt to variation in demand. The result is that cheap hydroelectricity is sent to the Netherlands during the day at peak time, while at night Dutch thermal energy can be sold to Norway, which can in turn reduce its own production [Kapff and Pelckmans 2010].

Despite the launch of the Directive 2009/72/EC *"Concerning common rules for the internal market in electricity"* [EU 2009] and the fact that examples of good practice exist at the European level, the **European electricity market remains divided and fragmented** due to the obstacles that were mentioned above, lack of interconnections and fear of enhanced competition. In Chapter 3.1 and 3.2 we also saw how the application of the directive has been delayed in various Member States.

Even if signs of market opening and integration can be seen from increasing volumes traded on the spot markets and increasing market coupling across various regions [EC 2011b], the current market shares (as a percentage of total generation) of the largest electricity producers in the national energy markets is above 50% in more than half of the countries, implying that the European electricity market is dominated by **oligopolistic competition**, with a few large producers sharing control over production (see Map 8 [Eurostat database, 2009]).

Map 8: Market share of the largest generator in the electricity market (as percentage of total generation)



Source: [Eurostat 2009]

While there have been continued efforts in promoting regulatory harmonisation and congestion management procedures, most of the current **infringement procedures** opened by the European Commission have identified the need for better integration of **congestion procedures** [EC 2011b]. Grid infrastructure access in large portions of Europe is dominated by a few large players, leading to further, **heavy market distortion** [EWEA 2010a]. Moreover, as pointed out in chapter 3, the insufficient number of cross-border interconnectors often leads to congestions and eventually higher prices for the worst connected areas. Lack of interconnections exacerbate the problem with existing bottlenecks between MS and the difficult integration of RES from isolated and remote areas.

4.2.2. Cross-border issues and cost allocation

In order to foster the integration of renewables into the network system, it will be fundamental to ensure that the electricity market can rely upon smooth access to interconnectors and free flow of electricity. Increasing interconnector capacity and reinforcing the grid infrastructure among different countries often leads to **cross-border externalities and cost allocation issues**.

Currently, local governments and network owners are unlikely to finance projects that would not bring any **tangible benefit** to their own country. It is also difficult for TSOs and local authorities to justify the full cost of an investment if this creates benefits for third countries. It can become very complicated to establish, by means of modelling or estimation, what share of the cost each participant should bear on the basis of the likely benefits (see also chapter 2.6).

This issue can be further appreciated when looking at an **example of a cross-border issue** presented by a report commissioned by the EC [Frontier Economics 2008]. Figure 33 shows the possible impacts of interconnecting three countries where price levels have historically developed in different ways. The arrows indicate that an infrastructure investment in country B would lead to an increased flow of electricity between country A (low price) and country C (high price).

Figure 33: Example of interconnection flows

Source: [Frontier Economics 2008]

Assuming to act in a perfectly competitive market, each country's price will be affected as follows:

- In country A, prices will increase due to the increase in demand for exports of electricity;
- In country B, prices will remain unchanged (assuming that the power that flows in equals the power that flows out);
- In country C, prices will obviously decrease thanks to the inflow of cheaper energy from country A.

In this case, countries A and C benefit either from increase rent for producers or lower price for consumers, whilst country B would incur in the cost of reinforcing the grid without gaining any economic or welfare benefit. This example illustrates that the incentives for individual countries to invest are not always aligned with overall European interests.

Under the provisions of the recently launched EIP, Article 12 *"Energy system wide cost-benefit analysis"* of the guidelines proposes that ENTSO-E should prepare a **methodology for a harmonised cost-benefit analysis of projects of common interests**. Under the supervision of the EC and ACER, this methodology for cost-benefit analysis will be applied to all following TYNDP projects [COM(2011)568final].

Under provision of the same package, Article 13, *"Enabling investments with cross-border impacts"* states that the costs of projects of common interest will be covered by the **National TSOs** to whom the project delivers profit.

The article also establishes that **national energy regulators** will have to jointly approve of investment costs and to take into account investment needs when deciding on transmission tariffs [COM(2011)568final].

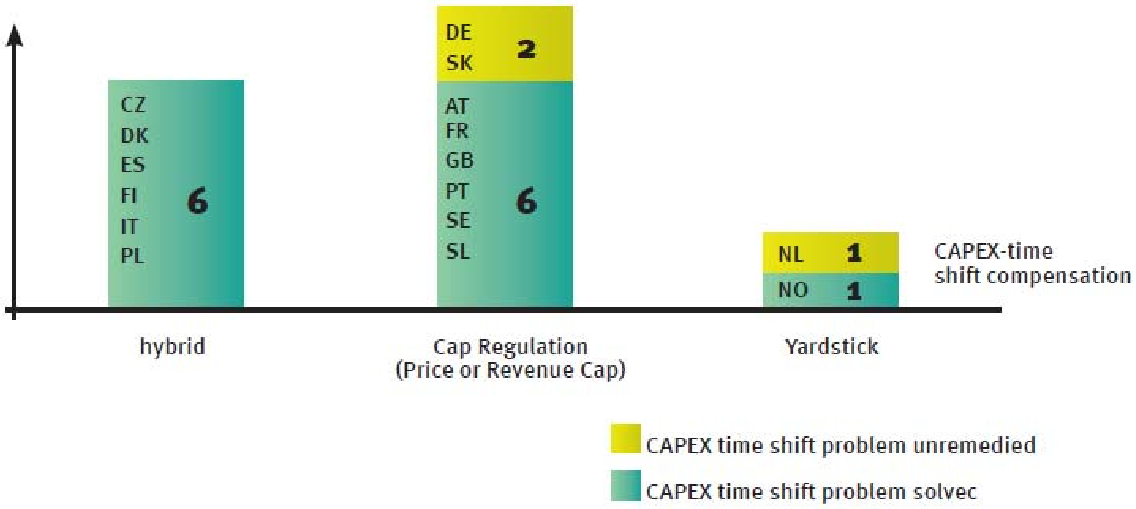
4.2.3. Disincentives to invest in Smart Technologies for DSOs

DSOs have very little incentives to invest in either new infrastructures or new technologies, due to the regulated structure imposed by the national regulatory authorities (NRAs). NRAs usually command the rate of interest for new investment, which often reveals to be too low for the DSOs to make a profit.

[Eurelectric 2011] states that the current regulatory system in place in some MS forces DSOs to *"destroy economic value rather than creating it".* This refers to the **"CAPEX time-shift problem"**, which according to Eurelectric remains a problem in three important countries.

By definition, capital expenditures or CAPEX represents the investments made by firms to accrue their level of profits in the future. In the case considered, for example, the DSO can either build more distribution lines or update the current infrastructure system to make it "smarter". However, due to current regulations in most European countries, when setting up allowances for revenues and prices the costs related to CAPEX are not acknowledged in time: this leads to a situation in which DSOs are unable to cover the costs of new investments with their revenues in a short period of time.

Figure 34: Overview of EU countries where the CAPEX time shift has/has not been solved



Source: [Eurelectric 2011]

Figure 34 above shows that those European countries whose systems have been modified managed to avoid distortions by implementing either a hybrid system with "a rate of return-regulation" or a price/revenue caps. According to the Eurelectric study, the CAPEX time shift problem remains in Germany, the Netherlands and Slovakia, where there are **delays of up to 7 years** before the investment costs can be integrated in the revenue cap (note that not all EU countries are included in this study, but in any event the problem largely persists).

A few MS, notably Italy, Finland and the UK, have attempted to inverse this trend by providing DSOs with proper incentives to invest into new technology through the regulatory framework. In the case of Italy, the energy regulator has started a competition to promote smart infrastructure projects. The relevant projects will benefit through an extra 2% in weighted average cost of capital for 12 years [Eurelectric 2011].

TSOs find themselves in a similar position because, due to the particular nature of infrastructure, projects returns are tangible only a **long time** after the construction of the project itself.

Another issue is related to the evaluation of project efficiency, usually based on benchmarking methods, reference networks and/or standard costs [Eurelectric 2011]. If the needs for smart grid deployment are not included in these evaluation projects, **smart metering projects** cannot be classified as efficient costs.

Another important obstacle is that in many MS the legal frameworks need to be stabilised and clear roles have to be assigned. Smart metering, for example, has typically been deployed by the DSOs who have been in charge of the process; however, in various countries the **roles and responsibilities still have to be defined**.

The guidelines for energy infrastructure projects, included in the EIP, Article 14 "*Incentives*" state that NRAs may be granting **special incentives** in the cases where stakeholders are facing relevant risks for the development of a project of common interest [COM(2011)568final].

4.2.4. Lack of private financing and equity access

The main actors and structure of the actual financing models for large infrastructure projects are presented in chapter 2. The overall conclusion is that, **in the future, private equities will have to cover a bigger share of the overall investment** than at present, in order to fulfil the EC investment estimates of €200 billion and to avoid any financing gap.

Overall, private investors such as pensions or insurance funds do not currently represent an important share in financial support for infrastructure projects and the energy sector in general. The same is the case for the deployment of renewable energies and in particular the grid roll-out [Roland Berger 2011]. Private investors (owners of insurance and pension funds, but also commercial banks) act as **risk-adverse** agents, and prefer to make investment choices on the basis of previous sound records and secure future margins [Roadmap 2050].

[De Jager 2011] says that the uncertainties related to "*specific risks by technology*", such as the switch from above ground to underground cabling systems, are exacerbated by an overall uncertainty on the **future direction of European energy policies** and a **perceived lack of readiness among Member States to promote the right projects**. There also seems to be a total lack of interactions between European investors and stakeholders such as TSOs.

Corporate bonds are often chosen to finance TSO investments. Having a good credit rating is however a fundamental requirement to be able to issue **corporate bonds** successfully. Even if most European TSOs have a **good credit rating**, it is important to contextualise those ratings according to the regulatory regimes applied in the country of residence. Due to the recent application of unbundling measures and liberalisation of the electricity market, many TSOs are still state-owned or vertically integrated, and therefore lack a valuable stand-alone rating [Roland Berger 2011]. As a result of this regulatory hurdle, many TSOs do not have the possibility to issue any corporate bonds, which are, however, an appropriate form of investment for long-term infrastructure projects.

It can be noted that among those TSOs who have stand-alone credit rating, European TSOs have good credit rating. For those companies with lower credit rating, the effect is more evident on the **cost of the debt** itself rather than the access to credit [Roland Berger 2011].

One more discouraging element for investors is the overcharged system of **permitting procedures** and **environmental impact assessments**. The length of the administrative permitting procedures is an important factor influencing decision-making for TSOs themselves, as it may of course lead to increases in costs and also pose a risk for the projects final accomplishment itself.

Article 15 (Chapter V, "Financing") of the guidelines in the EIP provides guidance for the possible criteria of ***"Eligibility of projects for Union Financial Assistance",*** according to which projects of common interest will be deemed eligible for EU funding, in the form of either grants or financial instruments. The type of financial instruments is defined in the communication "Creating Connecting Europe Facility", where the EC promotes the use of "innovative financial instruments", such as the **Project Bond Initiative (PBI)**, along with the customary EU funding approach (see chapter 3.6.2).

4.3. Social obstacles

[European Commission 2010b] argues that the lack of public acceptance has negative impacts on the selection and development of energy infrastructure projects. That is why promoting social acceptance is also an important part of the Third Energy Package. At European level, there have been various instances in which local public resistance to new infrastructure developments attracted attention. The most famous example is the construction of the electricity interconnector between Spain and France, of primary importance for the development of a European Supergrid, which **took 20 years to be approved** because citizens were fiercely opposing the project. In this case, the local population disapproved of the project because of the environmental damage and the negative visual impact on the landscape [Van Renssen 2011].

This section studies the issues that trouble the general public when affected by energy infrastructure deployment. The major reasons for discontent are considered: **environmental concerns, health and safety issues and the visual impact of new infrastructure**, which individually or together also lead to concerns about the economic impact on the **value of private property**. Additionally, this section will also present the obstacles posed by the roll-out of **smart meters**, with respect to data handling and risk of privacy breach.

4.3.1. Environmental concerns

Electricity grid deployment can potentially harm the surrounding environment, during the construction phase and also once the infrastructure has been put in place. Birds are the animals most affected by the implementation of new grid lines, especially if these are built in, or passing through, migration corridors. The three main negative effects on bird fauna are bird electrocution, risk of collision and overall negative impact on the natural habitat. According to NABU 2011[47], the actual amount of losses is difficult to estimate, since over 70% of the bodies disappear because of predators [Nipkow 2011].

[47] Dr Markus Nipkow 2011 Impacts of power lines on bird populations in Europe NABU – BirdLife Germany. RGI Environment Workshop, Glasgow, 16 June 2011.

Most of the **accidents** are caused by poor design of the infrastructure, which is insufficiently safe to protect the animals; for instance, bird electrocution is caused by insufficient distance between the wires, while collision is due to the low visibility of the cables [Nipkow 2011].

An **example of strong public resistance** organized by environmentally concerned NGOs is the implementation of the long distance power line between the **Italian island of Sicily** and the mainland (connection "Sorgente-Rizziconi"), whose approval was delayed for years due to the environmental protection area around the Messina Strait, which is a well-known "bird migration bottleneck". Finally an agreement was reached, specifying the construction of the new lines would be done underground on the coastlines [Interview Ministry of economic development, Italy].

Not only birds are affected during the construction and maintenance phase: human action can seriously **damage the surrounding environment**, such as forest and water resources. Whilst technical advances are still expected in order to minimise the impact on birds' lives, proper planning and construction are already possible thanks to the available technology.

In most cases, local NGOs and conservation associations organise the strongest resistance to the construction of new lines, if these are expected to go through untouched natural areas.

However, things might be changing soon because, although for years NGOs and TSOs did not share any common target, many European and international NGOs now recognise the **importance of grid development in order to achieve the renewable energy targets**. This has led to a series of actions and initiatives in which TSOs and NGOs have started constructive dialogues in order to find good compromises [RGI Interview].

4.3.2. Health and safety issues

Concerns regarding the health risks related to heavy exposure to electromagnetic fields also lead to strong resistance to the construction of new lines. This is mostly due to a **lack of knowledge** concerning the real risks, which are often overestimated and perceived in a disproportionate manner by the population.

Exposure to electromagnetic fields (EMFs) has increased over the past years and originates from a variety of sources, from cell phones and domestic appliances to low and high voltage electricity grids; the highest level of exposure can indeed be found next to high voltage transmission lines and can reach an electric field level of over 5 kV/m. The strength of exposure is directly related to the distance from the lines with the maximum exposure just under the power lines [SCENHIR 2007]. This said, however, it is evident from Table 12 that exposure to EMS near power lines is currently classified as "Extremely low frequency" (ELF) fields.

Currently available research, mostly on child leukaemia and breast cancer, has led to the conclusion that ELF could be "partly carcinogenic to humans"; however, data are limited and findings only relate to sources around magnetic field levels of 0.3/0.4 mT [SCENHIR 2007]. Researchers have found no correlation between exposure to ELF and adult cancer, or cardiovascular diseases and "ELF symptoms" [SENHIR 2007]. Concerning the risk related to child leukaemia, the study concludes that more research will be required in order to clarify certain discrepancies.

At 50-100 m distance from the overhead power lines, the fields are normally at levels that are found in areas away from high voltage power lines [WHO].

Table 12: Sources and average strength of electromagnetic fields

Frequencies	Frequency range	Examples of exposure sources
Static	0 Hz	VDU (video displays); Magnetic Resonance Imaging (MRI) and other diagnostic / scientific instrumentation; Industrial electrolysis; Welding devices.
ELF	0-300 Hz	**Power lines; Domestic distribution lines**, Domestic appliances; Electric engines in cars, train and tramway; Welding devices.
IF	300 Hz – 100 kHz	VDU; anti-theft devices in shops, hands free access control systems, card readers and metal detectors; MRI; Welding devices.
RF	100 kHz – 300 GHz	Mobile telephony; Broadcasting and TV; Microwave oven; Radar, portable and stationary radio transceivers, personal mobile radio; MRI.

Source: [SENHIR 2007]

It is worth noting that in most cases exposures to ELF do not exceed the regulatory fields but that public attention is however usually strongly focused on the issue [Realisegrid 2010b]; this would be mostly due to the fact that local opponents tend to overstate the actual health effects of ELF, while the general public usually lacks the scientific knowledge to discern the real risk.

4.3.3. Negative visual impact on landscape and land value

The construction of new grid lines can also be strongly opposed because of the impact on the landscape and the way this affects the value of property for landowners. Due to the **very strong negative perception of transmission lines** (especially high voltage ones), the value of property where new power lines are built is usually negatively affected. This reaction is often known as NIMBY, "not in my backyard", or even "NUMBY", "not under my backyard" for storage projects.

Concerning the changes in the landscape, Jhon Van Veelen observes the following as the source of resistance: "The relationships between the functions, forms and meanings of the various landscape elements underpin the distinct identity of a particular location, the perception of its aesthetic beauty, and the sense of belonging it can generate" [Van Veelen 2011]. Van Veelen then argues that the building of new power lines disrupts and destroys the relationship created between a particular location and its habitants. To **minimise the negative impact**, it is important to ensure that new power lines are designed in a particular way. The best way for new lines to become less obstructive to human eyes would be in effect to have only "straight lines", which can be easily ignored by the brain after it has got accustomed to it [Van Veelen 2011]. In many cases, this turns out to be impossible because of populated areas or even environmental reserves, where straight lines cannot be built, but could in any event be taken into account when and where possible.

In order to promote early interactions between project promoters and the public involved, the EIP proposes that the stakeholders involved will have to elaborate and submit a plan for **public participation** and organise a **public consultation at an early stage** of the application phase, informing all stakeholders of the possible repercussions of the project, while attempting to identify the **best locations and alternative routes** [COM(2011)658final].

4.3.4. Impact of new system management on consumers

The changes brought about by the integration of RES in the network systems will not only affect our surrounding environment with more lines and pylons, but will also have considerable impacts on the way we will have to use electricity, in relation, for instance, to the use of domestic appliances.

Smart grid *"is an intelligent energy system that encompasses the interconnection and control over energy producers, storage facilities, consumers and the grids"* [Eurelectric 2011]. While on the suppliers' side production management implies a complete renovation of the current system management, from an end consumer perspective the expected deployment of smart meters in Europe (80% full scale deployment by 2020 is targeted) will give end users the possibility to better manage their energy consumption.

The **large scale deployment of smart meters** is partly a matter of regulations: as long as the EU targets are reached, it is in fact discretionary to the national regulator and government to decide when full deployment has to take place and under which conditions. Sweden was the first country to plan smart metering deployment, while Italy was the first country where massive deployment took place; currently, a large deployment phase is also being prepared in the UK [Berg Insight 2009].

While smart meters are supposed to empower end users into making choices they are unable to take now, they will also allow utilities to have more access and better knowledge of the level of consumption data of each customer. This is perceived as a **risk for the privacy and data security of individual citizens**. There are worries regarding the way energy consumption data will be handled, for what purpose and by whom they will be handled. People fear DSOs may make an improper use of such data to gain economic profit.

Recent research also showed that **consumers' experience** with smart meters has been disappointing: for instance, consumers did not benefit of any actual economic gains or the design of the smart meters turned out to be unfit for everyday use [Mc Leod 2011].

Moreover, it is uncertain how consumers would react to a situation in which the price of electricity would constantly change during the day, forcing them to continuously shift consumption. If we consider current everyday behaviour, it is evident that the **mentality change** would be abrupt. In general, consumers tend to be risk-averse and prefer fixed energy prices rather than fluctuating ones; besides, for certain MS price changes in the short term do not have major effects on consumer behaviour, since the **energy bill** is a considerably small share of a household expenditure [Olmos et al. 2011c]. For those countries where energy bills are a large share of household expenditures, smart metering might provide a solution as various tariffs will be applied daily and it will be possible for consumers to choose to consume at the cheapest time.

Finally, energy consumers are unlikely to react positively if they were to be cut off the power to balance the grid, even if an adequate system of compensation was established.

It will therefore be very important to **educate consumers** on the need for power balancing and promote appropriate incentives, without increasing prices too much during peak times, in order not to discriminate poorer households. The most successful mechanism to incentivise consumers to fully adopt the smart metering system is by sending adequate price signals, i.e. different tariffs according to the time of the day and the overall energy demand. In the long run, network externalities will affect the overall price mechanism, until we will witness price convergence of energy tariffs.

Energy regulators will have to promote proper harmonised regulation across the EU to ensure that data on energy consumption obtained through the reading of smart metering cannot be misused by the utilities for marketing purposes. Additionally, smart metering should be beneficial to **lower income households** and help preventing **"fuel poverty"**. In fact, thanks to more specific data on energy consumption it will be possible to prepare **targeted tariffs for poorer households**.

4.4. Administrative

The current legislative framework leads to **long delays** for decision-making and projects deployment and, according to the results of the interviews, stakeholders consider the regulatory framework, permitting procedures, and the lack of harmonised system of Network Codes as probably the **biggest obstacles** to the deployment of a pan-European electricity grid.

It is important to open this section with some considerations on the current situation of the regulatory framework in Europe and the need for further harmonisation at the European level on regulations, codes and standards. The study then further analyses the need for a harmonised system of Network Codes and synchronised grid access for decentralised energy producers.

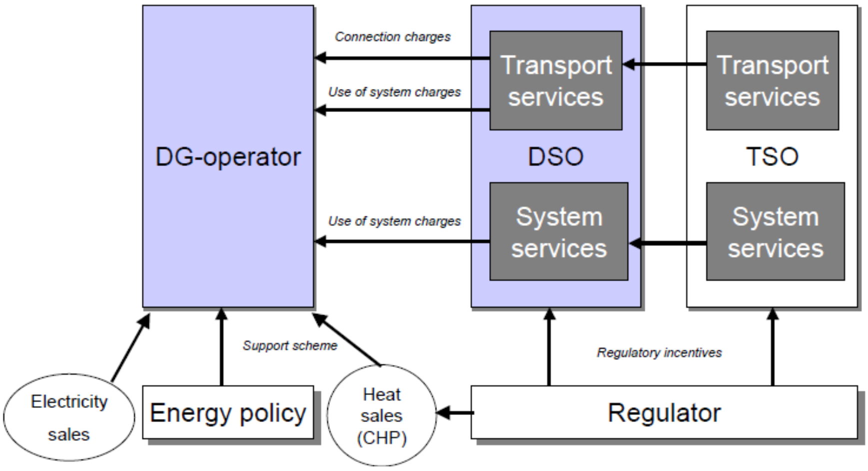
4.4.1. National Regulations and the impact on infrastructure development

Historically, electricity network management and expansion were entirely in the hands of nationalized large utilities, vertically integrated TSOs and DSOs, subject to the control of national regulators, with very little interconnections across European countries; this still characterises the European **regulatory framework, which overall looks very heterogeneous**.

Today, as explained in section 4.2, **energy regulators** in most European countries interact directly with the national TSOs and DSOs, in most cases determining tariffs, rates of return on investments and the general policy frameworks. Since most electricity grids are run according to a **"natural monopoly"** structure, energy regulators play the indispensable role of preventing the monopoly to gain excessive profits and keeping prices low to **avoid overall social welfare losses**. The system through which regulatory agencies derive tariff structures implies that TSOs have very little margin of freedom with respect to the deployment of new projects and innovation, including the **building of new infrastructure** (see chapter 4.2). Therefore, the deployment of new RES-E and energy infrastructure varies greatly according to the support schemes in place in each Member State [GreenNet-Incentives 2008].

Figure 35 shows a schematic approximation of the interaction between TSOs/DSOs and the national regulators [DG-GRID 2005]. Whilst TSOs and DSOs have to firstly comply with the norms specified by the energy regulators, **DG-operators** are constrained between TSOs/DSOs and the overall structure of energy policies, and the interaction with the electricity markets and inherent economic aspects such as tariffs and connection charges.

Figure 35: Stakeholder interaction with regulators



Source: [DG-GRID 2005]

EU regulations and implementation

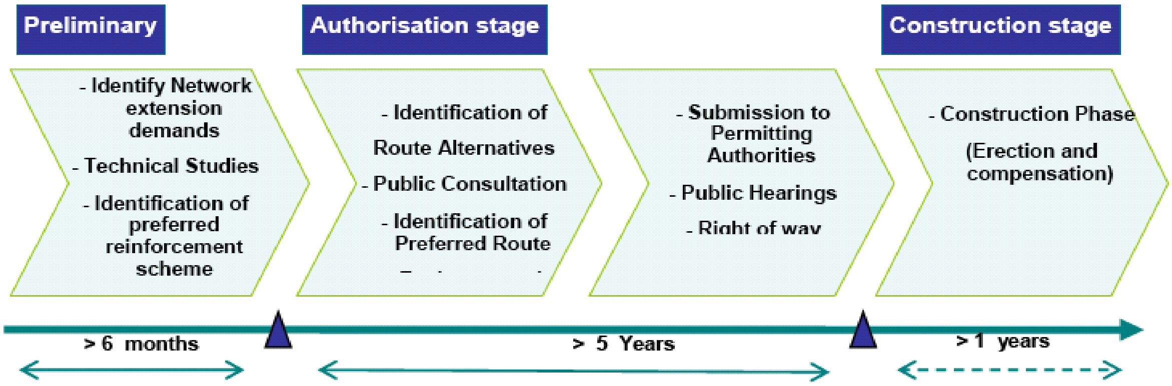
Since the implementation of the Third Energy Package and the progressive integration of the electricity market, it has been clear that complete market integration should be achieved at some stage, but that different steps and intermediate measures are necessary. The European Union is moving from a fragmented energy market system to a single integrated European market. The **harmonisation of the regulatory framework at the European level** will be particularly beneficial to the integration of renewables into the energy network, because it will allow a smoother running of infrastructure project development and coordination across Member States.

4.4.2. Permitting procedures

In the Priority Interconnection Plan (PIP), the EC identified 20 of the 32 electricity projects of "European Interest" that were facing **considerable obstacles** and **were excessively slowed down by administrative hitches**. While many of the issues already mentioned are brought in cause, the Communication points out that *"the complexity of planning and other authorization procedures is the major reason for most delays"* [COM(2006) 846]. Given the importance and the extent of electricity infrastructure projects, clear and sound norms are vital for the deployment of any such projects, also to ensure that all stakeholders respect their duties.

The **legal permitting procedure** for energy infrastructure appears to be a complicated patch of different policies and norms, sometimes conflicting with each other. Figure 36 shows the average length and different stages of acquiring the relevant permits for the building of new grid lines [Realisegrid 2011c].

Figure 36: Schematic representation of the authorization process for an infrastructure project



Source: [Realise Grid 2011]

Within the first 6 months, the TSOs need to identify the actual infrastructure needs and evaluate the best practice to reinforce the grid. This is done through a series of technical studies, including cost-benefit analysis of all relevant options. During the first part of the authorisation phase, the TSOs are required to look into different alternative routes and promote public consultation. Once this mid-stage is completed, the TSOs need to present their plan to the permitting authorities. At this stage, it is relevant to point out that TSOs have to deal with a whole array of different authorities, which implies a much longer permitting procedure: this mostly has to do with the fact that these very same authorities do not follow the same procedures and practices. It is also important to note that the overall permitting phase should take 5 years but instead, according to our literature review and discussion with interviewees from Eurelectric, EWEA, TSOs and local authorities, the **actual average length for implementing a project is 10 years** (or more). TSOs are hoping to achieve the **targeted 5 years** in the near future.

To briefly resume the discussion above, administrative procedures hindering the implementation of renewable grid projects are usually related to a series of common factors [OPTRES report]:

- The **large number of authorities** involved in the actual permitting procedures;
- The **lack of coordination** among such authorities;
- The **lack of transparency** with respect to the main guidelines.

Not to be forgotten is also the impact of the complicated system of environmental impact assessment, which will be analysed in the next sub-section below.

With the recent launch of the EIP, the EC also proposes the **designation of one national "competent authority"** that will take charge of all permitting procedures for projects of European interest [COM(2011)658final]. Article 11 of the proposal states that the overall permitting phase should **not exceed 3 years**; if a project encounters particular difficulties, the EC could be entitled to nominate a **"European Coordinator"** to solve the issues. The European Coordinator, a person (legal entity) with specific knowledge of the issues involved, will hold the project under scrutiny. The procedure of appointing European coordinators is not new within the energy infrastructure framework. Four coordinators have already been designated for infrastructure energy projects of European interest that came to a halt because of major difficulties. Here below the projects and the respective coordinators [DG ENER]:

- The French-Spanish connection (Mr. Mario Monti)
- Baltic and North Sea off-shore wind connections and the "Salzburgleitung": Austrian Power link Salzach neu - Tauern (Mr. Adamowitsch)
- The axis linking Caspian Sea countries and the Middle East to the European Union, including the Nabucco pipeline (Mr. van Aartsen)
- The northern European power-link (Mr. Mielczarski)

CASE STUDY: Facilitate permitting procedures, legislation in Germany

The "*Transmission Line Expansion Act*" has been implemented in Germany since 2008 with the purpose of consistently reducing permitting procedure lengths, in view of the large future deployment of RES-E. The law simplifies permitting procedures for new transmission lines and fosters the utilisation of new technologies such as underground cabling. In order to speed up the development of "priority projects", for instance, applicants will need to go only through one application process. The act has only been in place since 2008 and it is therefore too soon to assess its impact.

4.4.3. Environmental Impact Assessment EIA/SEA

The procedure of Environmental Impact Assessment (EIA) was established by Directive 85/337/EEC, also known as the EIA Directive, in 1985.

"Environmental assessment is a procedure that ensures that the environmental implications of decisions are taken into account before the decisions are made" [DG Environment]. An EIA has to be undertaken for any project, from dams to motorways and power lines. To further assess the impact of "public plans", Directive 2001/42/EC, or the Strategic Impact Assessment (SEA) Directive, was established in 2001. Both aim at ensuring that, through assessments, the environmental impacts of a project are evaluated before it is developed; they also ensure that **local authorities** are involved and that **consultation with the public** is endorsed.

Through the project "Realisegrid", researchers have analysed the current status of existing infrastructure approval procedures by interviewing TSOs in Austria, Italy, the Netherlands and Germany; the study summarises the main obstacles to grid rollout, i.e. permitting procedures and administrative burdens. The **EIA was found to be an important barrier** throughout the permitting procedure phase, mostly due to the optimisation analysis required throughout the environmental impact assessment. Participants to the study also criticised the lack of trade-off analysis between the project public interests and environmental security. The EIA report has to be compiled along with national regulation on environmental protection.

The EIA in its current form is perceived as an obstacle by the main actors because it is too **detailed and costly**; in some instances (Italy and Austria), EIA prerequisites are requirements for obtaining certain licenses, which further delays the final approval [Realisegrid 2010a].

Since environmental requirements are often seen as a heavy burden on the planning of infrastructures, the TSOs and NGOs have started working together through the **"Renewable Grid Initiative"**. The expected outcome will be the publication of a statement on the promotion of renewable grid infrastructures, with clarifications **narrowing down the major environmental issues that need to be addressed**.

4.4.4. Network Codes

Network Codes (NC) consist of specific technical requirements that Power Generating Facilities are required to fulfil in order to be able to connect to the network [ENTSO-E 2011]. The first grid codes were established to accommodate the need of a network with intensive centralised production. The NC were established to fit for large coal/gas plant, and do not match the characteristics of DG such as wind energy and photovoltaics.

European Network code

The Third Energy Package enforces the elaboration of binding European NCs in order to facilitate the process towards the integration of the electricity market through partial harmonisation of national NCs.

ENTSO-E is in charge of **providing a harmonised system of Network Codes** following up on the framework guidelines provided by ACER. The electricity directive specifically states that *"the Network Codes shall be developed for cross-border network issues and shall be without prejudice to the Member states' right to establish national Network Codes which do not affect cross-border issues"* [EC 714/2009]. Cross-border issues are defined as policies that should promote and support the completion of the European electricity market, actively promote the achievement of renewable penetration targets and maintain security of supply [ENTSO-E 2011]. In short, once the harmonised system of NC will be established, MS will still have to run their own NC on the side.

With over 30 different national NCs, wind energy producers need to adapt to a whole different array of technical requirements that do not match DG production, lead to increased costs and reduce efficiency [EWEA 2011c]. The situation is particularly damaging for the **wind industry** which is the sole renewable with a consistent penetration level into the HV transmission grid: during an event recently organised by EWEA on grid codes access, it was argued that specific requirements for wind integration are a pressing issue to be inserted into the new European NC.

Stakeholders have already interacted with ENTSO-E and provided feedback on the current **Pilot network code**, published in March 2011; there are doubts concerning the actual level of harmonisation between different European code requirements, and the lack of clauses concerning technology development, which are obviously very important in the renewable energy sector [Quintmann 2011].

4.4.5. Grid access

Currently, grid infrastructure develops at a slower pace than RES production plants. Not only lack of infrastructure poses a problem: the DG energy producers are also encountering many administrative barriers to access the grid. Difficulties in accessing the grid hinder market access and diminish the number of new ventures started. **Smooth and preferential grid access** for renewables is a prerequisite to fully deploy their potential.

Connection charges

DG operators are required to pay connection charges to get access to the electricity grid, even if the systems for this are varying between Member States. [Olmos et al. 2011c] identify three types of connection charges: shallow, "shallowish" and deep. The first is the most favourable to the DG operator because it only pays the connection to the nearest network (e.g. Denmark). In a "deep system", however, the DG operator has to cover all the costs related to the grid connection, whilst the "shallowish system" is in between these two extremes [Olmos et al.2011c].

Other barriers to grid access

Within the wind sector, there have already been important findings with respect to the integration of renewables at high voltage level and the respective barriers. The connection of wind farms to the grid is a long and complicated process: according to EWEA, the **average lead time for grid connection** is 25.8 months for onshore projects and 14 months for offshore, although with big differences among European countries (for instance, Denmark performs much better than all the other countries with an average lead time of only 2 months for grid connection). Apart from the local DSOs and TSOs, the average **number of external authorities to be contacted is 24** for onshore wind projects and 4.4 for offshore. Remarkable exceptions to these averages are Denmark, Estonia, the Netherlands, Romania and UK, where an average of **3 authorities** have to be contacted [EWEA 2011c]. The average connection costs represent 5.13% of the total cost for onshore and 5.43% for offshore projects [EWEA 2011c].

For PV installations, the recently established project ***"PV Legal"*** also looks into the administrative barriers to PV deployment across European countries. It is found that administrative burdens and uncertain policies penalise PV deployment across the EU [EPIA 2010].

Other types of barriers to grid connections relate to **public acceptance, land ownership and insufficient grid capacity** that penalises newcomers [EWEA 2011c].

CASE STUDY: Grid access, barriers and solutions in Europe

The **Polish case** illustrates how the lack of transparency and clear norms on grid access lead to a situation which hinders the progress of the renewable energy sector. For instance, when the project promoter applies for grid access, the DSOs do not provide any deadline on the application results, which creates uncertainties about when the construction phase might start. Moreover, even if by law priority should be given to RES access, DSOs and TSOs are able to bypass this requirement through a series of loopholes [WindFacts 2009]. In the Scandinavian region, both **Finland and Sweden** have seemingly overcome these issues. In Finland, a clear set of rules has been established for grid operators, which enables stakeholders to plan ahead and invest adequately in new plants, additionally the low level of grid access tariffs further encourages development. In Sweden, grid access priority is given to renewables and RES producers are not required to demand any permit [Ecorys 2008].

4.5. Political Willingness

Political support of energy infrastructure projects is vital for the integration of renewables into the network system. Politicians need to soon acknowledge the importance of these projects in order to achieve the target of a decarbonised European economy. This subchapter will look at the timeline imbalances between political actors and energy infrastructure priorities, the need for better knowledge of energy infrastructure projects by politicians, and will provide a few illustrative national examples of decision-making processes in the energy field in Europe.

4.5.1. Timeline imbalances and lack of awareness and understanding

The energy infrastructures required to ensure the full integration of renewable energy into the energy network are commonly developed in a very long time span: over 20 years may pass from the approval phase to the construction phase and final activation. The actual benefit of any such projects will therefore be felt many years after the planning phase.

The political scene, though, moves at a much faster pace, elections (local or national) are typically run every four years and politicians tend to **prefer short-term to long-term priorities**.

Lack of awareness and insufficient understanding of the issues involved may have a negative impact on policymaking decisions [IPCC, 2011, chapter 11]. Policy makers often **lack the required knowledge** (of technology, related costs, required policy) to be able to back up radical changes in the network system, which, as already seen, are **often opposed by their electorate**.

4.5.2. Political decision for infrastructure deployment in the energy sector

The energy sector easily catches major attention in the public eye due to the sensitivity of the problems involved, and it has become ever more important to decide who takes decisions regarding these issues. As in many circumstances before, at the political level the European panorama on political decision-making is all but homogeneous.

National governments have a say in the processes developed at the European level: for instance, in the development of the European NC, while ACER is entitled to produce general guidelines and ENTSO-E produces the actual text of the NC, the final decision rests with the Member States through the **comitology procedure**.

One of the major issues with the development of new grid infrastructure is the general public resistance to the implementation of pylons and lines on their land, the so-called "Not in my backyard" (NIMBY) issue. It is indeed very difficult to **promote acceptance** of infrastructure projects on the basis of increased **overall welfare** issues. In order for people to better understand the need and importance of such projects, politicians will need to give **stronger signals towards RES promotion**, while also ensuring that **proper compensation mechanisms** are in place. It has already been found in some instances that political decisions concerning renewable energy production are at times conflicting and confusing for the population, creating a **climate of uncertainty** for the future.

When it comes to decision-making on infrastructure deployment, responsibilities are either shared between local and national authorities or are the sole responsibility of the central government. In the first case, the decision-making process may be very complicated due to the political struggle each side engages on. A few examples of **different systems for political decision-making** in the energy sector at the national level are presented below.

CASE STUDY: The UK

For infrastructure decisions in the UK, it is the national policy framework that establishes what level of government is in charge of what. For instance, low voltage grid lines (i.e. under 50 MW) are dealt with by the local authority, above 50 MW responsibility is taken by the central government. This is because large scale projects are considered of strategic importance for the State and can therefore only be dealt with at the national level. Local authorities do have a say, but can only partially influence the final outcome.

CASE STUDY: Italy

Italy also represents a difficult case, as the initiative and authority related to the energy dossiers, including energy infrastructure, is equally shared among local governments (regions) and the central government. This often leads to a situation in which the central government attempts to promote infrastructure development (especially in the more isolated regions in the South), whilst the local authorities take side with the population and oppose the projects. Typical of Italy, local politicians tend to be very related and connected to their territories. Steps are being taken in order to centralise energy infrastructure decision-making into the hands of the central government to avoid huge delays in future planning [Interview Ministry of economic development, Italy].

CASE STUDY: The Energy political agreement of Denmark

Thanks to a long lasting experience with wind energy integration, Denmark has a very favourable environment to the deployment of RES and their integration in the network system. In Denmark there is no contrast between local and centralised decision-making. The final say rests with the central government, in agreement with the TSOs, DSOs (which are fully nationalised) and local authorities. Since 2008, the overall process of deployment and implementation of energy projects has been run on the basis of the national political agreement of 21 February 2008 [Danish Energy Agency Interview].

To overcome the issue of public acceptance and satisfy the request of the population, the Danish government has approved a national political agreement. Thanks to this document, the implementation of new connections lines is approved in advance; however, the agreement requires for all projects to be furnished with underground cabling systems, which act as a partial compensation for the grid extension towards citizens, while allowing TSOs to complete their projects.

5. Policy recommendations

As a general conclusion, the integration of increasing shares of fluctuating renewable electricity into the grid is a long-term task that requires major investments, long-term planning at European level and endurance. It requires a significant action to coordinate all the relevant stakeholders in Europe, including policy, grid operators, research and civil society. Relevant activities have started, but efforts need to be stepped up, and action accelerated, in order to optimise grid development and avoid the grid being the limiting factor for the targeted growth of renewable energy development in Europe.

5.1.1. Cross-cutting issues

Long lead times to realise energy systems, both infrastructure and generation equipment, and long technical and economic lifetimes require long-term targets as the basis for decisions in the energy sector. "At the same time, this requires intermediate targets to be set in order to have intermediate checks of ultimate target achievement. **Without intermediate checks corrective action may become very costly or even impossible to achieve**" [LBST, Hinicio 2011].

The *Roadmap for moving to a competitive low carbon economy in 2050* proposed by the European Commission and currently under debate in the European Parliament defines such intermediate targets [EC 2011]. Regardless of the concrete quantification of the proposed targets, it is recommended to adopt a long-term roadmap including intermediate targets. The **Energy Roadmap** published in December 2011 presents different scenarios for discussion. The 2030 renewable targets are supposed to be set in 2013.

Similar to the existence of **strategic reserves** of oil and gas in the European Union, future policy initiatives for EU transmission grid development should consider, allow or even demand for the installation of large scale and long term storage facilities for energy from renewable sources. The storage of renewable energy should be an integral element of the European policy line for EU energy supply security.

The massive introduction of **"smart" elements in energy infrastructure** opens new and potentially critical possibilities for failures, accidents and attacks. With respect to the electricity grid, this may lead to the complete breakdown of the electricity supply for longer periods. Measures at all levels must be taken to ensure the integrity of smart elements at least in critical energy infrastructure elements.

Transmission expansion helps to smooth out variability and decrease forecast errors in power generation with wind and solar power. However, there are other options to deal with these issues, which should be considered on equal footing in all policies:

- **Change of market design** and procurement of system services for more economic accommodation, e.g. shorter gate closure times, dynamic reserve allocation, ancillary services also from variable generation;
- **Generation (supply side) management**, e.g. more flexible conventional thermal power plants, dispatchable renewable power sources (such as turbines or gen-sets running on bio-methane) and even curtailment if electricity supply exceeds demand;
- **Conversion of electricity into final energy for other uses**, e.g. heating or as a transport fuel (e-mobility, hydrogen, synthesised methane, etc.);
- **Flexible demand**, e.g. dispatchable charging of e-mobility and other electricity loads;

- **Energy storage** (pumped hydro storage, batteries, hydrogen, compressed air storage, etc.);

The integration of fluctuating renewable energies requires **grid extensions and upgrades on all levels**:

- **Trans-border interconnections of the transport grid**, both between national grids and for the integration of off-shore wind farms;
- **National transport grids**;
- **Distribution grids**.

Large increase of solar PV can overburden **distribution grids**, which may require upgrades and extensions also on these voltage levels. On the other hand, distributed generation and decentralised electricity storage can relieve pressure from both the transmission and the distribution grid, and increase regional energy security. Therefore, the analysis of grid extension needs need to include all options on the level of the distribution grids, such as district energy storage options or the more complex and costly energy storage options for household PV systems.

5.1.2. Infrastructure priorities

Optimising the European electricity grid on the basis of a thorough **system-wide socio-economic cost-benefit analysis** is crucial to cost-effectively integrate RES-E into the network. Given the current lack of scientific analysis of this kind, it is ambitious to expect ENTSO-E to submit its methodology for an energy system-wide analysis only one month after the proposed Regulation [COM(2011)658] would enter into force. This is further complicated by the fact that four fundamentally different options exist to integrate variable RES-E: grid extension, storage, supply side management, and demand side response. ENTSO-E has a truly challenging task at best.

The following recommendations will allow for major contributions to optimising energy infrastructure priorities:

- **Computing the costs and benefits** of possible infrastructure investments is required, both to determine which infrastructure to build and to be able to properly allocate their costs to system stakeholders, which may be critical to getting construction approval. Infrastructure investments associated with the integration of RES generation may bring about substantial benefits beyond the expected increase in the level of RES energy that the system can safely absorb. **Extra benefits** of transmission are mainly related to the increase in the level of integration achieved among EU power systems. Benefits of storage capacity, demand response and generation response are expected to be of a local nature predominantly.
- Costs incurred when building and operating this infrastructure will probably be significantly lower than benefits obtained from them. However, investments in different types of RES-associated infrastructure (or those in distant RES generation plus the required transmission connection capacity) may exhibit a **high level of substitutability**. Hence, benefits and costs of the different possible infrastructure investments should be compared to determine which one to carry out.
- Some of the benefits of infrastructure **cannot be expressed in economic terms**. Others can, but are **highly sensitive to assumptions** made on the operation conditions in the system. Generally, there is a lack of reliable data on infrastructure costs and benefits.

In order to carry out appropriately cost-benefit analysis, the high level of uncertainty about the future evolution of the system should be taken into account. This, together with the large size of the relevant system to analyse (i.e. as big as the EU), makes it necessary to solve a very large problem to get accurate enough estimates of benefits and costs.

- This includes the need for including a large number of scenarios in the analysis far beyond the variety of currently available scenarios, which in general do not provide enough detail. **Future scenario calculations** commissioned by the European Institutions should be required to **publish input assumptions and results in detail**.
- The plans for cross-border interconnection up to 2020 are presented in the ENTSO-E **Ten Year Network Development Plan 2010**. The list is based on a bottom-up approach and prioritisation should be based on a top-down approach, which would reveal the relative merits of different projects. This work is on-going and **should be supported by research**.
- The prioritisations for 2020 should include a **longer-term view**, as the needs of post 2020 should affect what is planned and built before 2020. This will require even more from the research methods and approaches as the uncertainty concerning future generation and demand scenarios increases. Studies done so far serve to build up the required understanding, but a lot more effort is required and would be worthwhile.
- The proposed Regulation for the **Connecting Europe Facility**[48] would prioritise cross-border projects supporting North-South transfers in Western Europe and in Eastern Europe as well as build transmission in the North Sea and Baltic Sea area, which would help to transmit power from offshore wind farms and to enable increased balancing with Nordic reservoir hydro power. The **research performed so far is not decisive** on whether these prioritisations are optimal. The infrastructure investments are long-term and have a very high cost. Use of well-organised research efforts with robust methods is advisable.
- There is a broad set of **energy storage options** available at different development stages. However, there is no single energy storage option that can sufficiently cover all storage requirements in all European regions, i.e. from small to large scales as well as for short, medium to long term energy storage. Furthermore, the practical potentials of energy storage options and the future needs vis-à-vis other renewable electricity integration options are not yet fully clear. Thus, any EU regulation related to energy storage should be kept **technology-open**, i.e. avoiding a discussion of e.g. pumped hydro power without looking into alternative technological options.
- The stronger integration of **Scandinavian hydro power into the European electricity market** has to be considered a mid to long term option as sufficient transmission capacities are a prerequisite, which usually imply long lead times. Furthermore, in the case of Norwegian potentials, the conditions are unclear and need to be fully assessed.

[48] (COM(2011)665)

5.1.3. Harmonisation of markets

Integration of variable power generation is not the only driver for new transmission lines. **System operation security**, **security of European energy supplies** and **integration of electricity markets** are of similar importance in Europe. However, as the share of variable power grows, its influence will also grow.

Despite the efforts towards an integrated European electricity market, each national market is regulated rather differently by the EU Member States. National authorities seem reluctant to lose part of the control exerted over their respective national markets, a development that is nonetheless a **pre-requisite for the efficient operation of a pan-European system**.

Renewables can contribute to **decreasing fossil fuel import dependence**. On the other hand, some renewable inputs may become tradable across countries (e.g. biomass, solar power), raising additional import dependence risks. Import dependence is not necessarily a sign of insecure energy supplies, just as more autarchy (e.g. due to a higher share of renewables in the energy mix) would not necessarily reduce the risks of supply disruptions.

More important than import dependence in terms of security of supply is the risk of **natural variability** from an increasing share of renewables in the energy mix. However, the balancing challenge can be overcome by a variety of measures including

- Improvement of forecasting tools;
- Optimisation of existing flexible resources;
- Integration of different balancing areas through the **integration of balancing markets** as balancing is currently performed at control-area level, which does not allow for the sharing of balancing resources;
- Backup capacity;
- Mixing renewable energy technologies with different natural cycles, notably solar with a strong daily and less pronounced seasonal variation and wind with a strong seasonal variation;
- Demand-side management strategies.

Key recommendations regarding the **harmonisation of markets** include the following:

- Change of **market design** and **procurement of system services** for more economic accommodation, e.g. shorter gate closure times, dynamic reserve allocation, ancillary services also from variable generation;
- Different **charges and regulations for grid connections** have an impact on where variable power generation will be built. This can have large economic consequences from the power system perspective. Resource use planning and transmission planning should be combined for the best result.
- Where possible, **demand response** of large electricity consumers significantly facilitates the integration of renewable electricity in the grid and reduces the need for grid enforcement – or at least delays it until the share of renewable electricity becomes higher. **Market design** has to be in place that allows for the use of such options when scheduling power plants.
- Given the wide range of important tasks that **ACER** is entrusted with in the field of electricity alone – and which are highly relevant for cost-effective RES-E integration (e.g. balancing, Network Codes, support to the Commission with regard to electricity

infrastructure area) – it has to be ensured that it will be equipped with adequate financial and human resources.

- The **transposition** of the market integration measures of the **Third Energy Package** need to be closely monitored. Given a relatively high number of infringement procedures, it is too early to empirically assess the success of the Third Energy Package. It remains to be seen, for example, how efficient unbundling is when both the TSO and a major electricity producer operating in the TSO's control area are owned by the same MS.
- Member States should be encouraged to at least consider other options, for example interconnection, storage and demand response, before introducing **capacity mechanisms**.
- Regarding **harmonisation of support schemes**, the study concluded that although there seems to be no support for full harmonisation across the EU, EU member states will need to reconsider their national approaches to renewables support schemes with increasing interconnectedness of the EU internal electricity market. While there may be no need to have a uniform support system across the EU for all technologies, the same technologies should eventually fall under one support mechanism. Nevertheless, harmonisation is not only related to support schemes, but also regards **technical barriers**, which need to be overcome as a priority.

Finally, EU budget support to **grid financing** through the **Connecting Europe Facility, Cohesion Funds and Structural Funds** will play an important role in network extension. However, given the increasing need for infrastructure development projects in the coming years, action needs to be taken to enhance the level of private investment within the overall level of investment in infrastructure. In this regard, it is crucial to address investment uncertainties by **harmonising and simplifying regulatory standards, particularly with respect to permitting procedures and related risks**.[49]

The **Project Bond Initiative** (PBI) aims at creating suitable financial instruments for the financing of long-term infrastructure projects. Similarly, it should be considered to entitle stakeholders to a higher rate of return for projects of European interest within a system of "priority premiums".

Economic obstacles are important barriers that should be taken into consideration by policy makers. While TSOs fear lack of availability of private investments, market distortion, cross-border issues and cost-allocation issues pose serious problems to the deployment of new projects. Solutions are listed below:

- Promotion of electricity market integration with better prediction of RES production;
- Promotion of incentives for investment for both DSOs and TSOs;
- Providing stakeholders and private investors with the necessary incentives to cooperate.

Demand response with small electricity consumers, e.g. household appliances, is often discussed as an extension of **"smart metering"**.

[49] For more detailed policy recommendations on financing issues, please refer to section 3.5.2.

The integration of small energy using products, in high numbers and private hands for grid balancing has to be considered very carefully prior to large scale deployment, especially with a view to cost-benefit, system vulnerability/criticality and data privacy issues. The EU is the appropriate regulatory level for a coherent approach throughout Europe.

Social acceptance is seen by many as one of the major barriers to new projects deployment. It is important to remember that the issue is not public resistance per se, but rather the lack of dialogue and interaction between stakeholders and the public. The main public concerns are related to the environmental impact of energy infrastructure projects and NIMBY issues, i.e. resistance to large infrastructure close to populated areas. Policies to be applied include:

- Promote **interaction between stakeholders and the local population** at an early stage of the project deployment process;
- **Ensure widespread knowledge** of the issues involved, especially in relation to health and safety issues;
- **Improve the administrative procedures** related to environmental impact assessments, ensuring that environmental standards are not lowered.
- Public acceptance of grid extensions should be a subject of **intensified research**. In this regard, providing further support to initiatives such as The Renewables Grid Initiative and foster relevant projects in FP7 calls would be desirable.

Administrative obstacles are perceived as major barrier to grid extensions. The current regulatory framework and permitting procedures are still too fragmented at the European level for stakeholders to be able to cooperate and progress on project development in a timely manner. Policies to be taken into consideration are:

- Harmonisation of permitting procedures at the EU level (including Network Codes, which are essential for grid integration);
- Establishment of a single authority at the national level with whom stakeholders can interact ("one stop shop" approach);
- Simplified and harmonized grid access rule for RES producers.

Finally, politicians both at the European level and the national one will have to fully support and **promote the integration of RES in the network systems**, by also promoting the necessary infrastructure projects.

5.1.4. Nature protection

With respect to the potential conflicts between an expansion of the European renewable energy network and **nature protection**, the key conclusions are as follows:

There are many **impacts of renewable energy infrastructure on nature**. However, the scale of the threat is currently still rather limited (not least due to the currently low penetration of renewables in the energy system). This might change in the future, as network requirements increase with the share of renewables and as favourable sites (i.e. in terms of cable routing) with low risks for nature and wildlife become scarce.

Key strategies to avoid conflicts between renewables, related network expansion and nature include:

- **Energy efficiency**, which reduces the total amount of transmission lines needed;
- **Technical improvements** of electricity transport facilities (including underground cables), which reduces the risks of collision and electrocution of birds;

- **Early spatial planning and site selection** for transmission lines based on improved ecological survey data;
- **Capacity building** for better application of existing legislation, regulations and good practices related to grid expansion into nature protected areas;
- **Improved transparency and scientific conduct** for the "appropriate assessments" of new projects as laid out in Article 6 of the Habitats Directive;

The **Natura 2000 Network** sets a solid framework for the reconciliation of economic activities with environmental objectives. Appropriate deployment of this framework is essential. The EU and national institutions should increase their efforts to **raise awareness** about the Natura 2000 Network and its importance for biodiversity conservation. Above all, it is important to convey the idea that Natura 2000 sites are not excluded from economic activity, but that they are aimed at fostering economic activities while reconciling economic, environmental and social considerations.

5.1.5. Technology development

Technology will play a decisive role in addressing environmental challenges, such as climate change and pollutant emissions. Technology RD&D can provide advanced technical solutions to the integration of fluctuating renewable energies into the grid.

The **Strategic Energy Technology (SET) Plan** launched by the EU essentially sets the technical priorities for low-carbon energy technologies. Policy at EU and national levels coherent with SET-Plan priorities will need to provide additional leverage to SET-Plan technologies. Key areas include **regional policy, state aid policy and especially public procurement**, which is an underexploited tool to boost the deployment of low-carbon technologies.

In terms of technology development, the EU needs to address at least two types of failures relevant to RD&D of a **smarter electricity grid**. First, **RD&D barriers** need to be addressed, including the fragmentation of efforts across-borders. This requires a higher degree of technical and research coordination in the EU. Second, market failures and distortions need to be tackled. This requires inter alia the expansion of EU financial engineering mechanisms to support technologies of European added-value that are in the demonstration and early deployment phases, and thus subject to high market and financial risk. The EU can provide financial support through **tailored combinations of grants and loans**.

There is a broad set of **energy storage options** available at different development stages. Most technologies, notably batteries, hydrogen, adiabatic compressed air storage, etc., will benefit from enhanced research and development.

Grid technologies are commercially available. Nonetheless, new technologies are still being developed, such as HVDC Voltage Source Converters (HVDC VSC) or HVDC switches, which present specific characteristics apt to the deployment of offshore grids.

Technical obstacles to the integration of fluctuating renewables into the grid, mostly related to renewables variability and system management, are not perceived by the main stakeholders as major problems. It seems in fact that the current level of technology development is satisfactory enough to implement projects; stakeholders tend to agree on the fact that technical obstacles need to be approached on a case-by-case basis.

5.1.6. Electric mobility

Electric mobility includes **battery electric vehicles** (BEV) as well as **hydrogen fuel cell electric vehicles** (FCEV). Both have electric drive trains in common and rely on fuels that can be produced from renewable electricity.

Thus, flexible fuel production for electric vehicles is an important means of enhancing the integration of fluctuating renewables as it represents a growing flexible, dispatchable electricity demand.

For this, **regulatory frameworks** are required to ensure that BEVs are connected to the grid whenever possible, that communication protocols are interoperable and that participation in the electricity market provides for remuneration of this. In addition, if BEV or the driver's data are needed to realise such grid services, data security and privacy must be fully maintained. Furthermore, it is also discussed that BEVs may supply electricity to the grid ("Vehicle-to-Grid"), but the challenges are likely to prevail over the benefits. Finally, retired vehicle batteries may possibly still be used as stationary batteries in the distribution grid ("2nd life").

Power-to-gas production – either as hydrogen (H_2) or synthesised methane (SNG) – allows for grid balancing during fuel production, storage of electricity as a fuel for use in the transport sector, as well as re-electrification of gas to increase energy supply security. To this end, regulations for the uptake of **hydrogen fuel cell electric vehicles** (FCEVs) facilitate the overall integration of renewable electricity in the grid, e.g. through:

- Reflecting the higher energy efficiency of fuel cells compared to internal combustion engines, fuel cell-electric vehicles require a factor in accordance with **EU Renewable Energy Directive**, Article 3, Paragraph 4, Point c) for battery-electric vehicles; and
- Fostering hydrogen **infrastructure build-up in the context of the Trans European Network for Transport (TEN-T)** initiative in accordance with the Proposal for a Regulation on guidelines for the development of the Trans-European Transport Network[50].

[50] COM(2011) 650 final as of 19 October 2011, Explanatory Memorandum, Article 20 on "Infrastructure Components".

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ANNEX 1: EUROPEAN GRID EXTENSION PRIORITIY STUDIES

TradeWind

The EU TradeWind project [TradeWind] was the first EU-level study to explore the potential benefits of a European grid with better interconnections and improved power market design with high wind power integration level. The TradeWind study demonstrated that it would be economical to build more transmission lines for even a moderate increase in wind power generation in 2020 and 2030. Both wind energy and transmission system upgrades would contribute to reducing operational costs. In order to effectively integrate large amounts of offshore wind power into the power system, it is necessary to upgrade the onshore network as well. TradeWind had well developed scenarios for wind power expansion, but it used relatively poor time series data for wind generation. The assumptions about other forms of power generation were based on Eurelectric estimates and therefore did not consider the impact of higher wind penetrations of the TradeWind scenarios.

OffshoreGrid

The EU OffshoreGrid project was completed in fall 2011 [OffshoreGrid]. It focused on the techno-economic assessment of the offshore grid for connecting large scale offshore wind power and to enable more power transfers between countries. Different offshore grid designs were developed to compare their relative performance. Among the main findings of the project was the fact that particularly variable renewable generation would benefit from additional offshore transmission capacity, and that the operational savings of the studied more optimised offshore grid designs are about three times the additional investment. The largest challenges for the development were the timing of technology development, onshore bottlenecks, support schemes, financing the large investment and capital attraction. The project saw e.g. that integrated grid designs might conflict at national level, and thus policymakers and regulators should prepare means to support the offshore grid related solutions at multi-national level. In the overall recommendations, the OffshoreGrid consortium states that developing integrated solutions requires suitable political, regulatory and market conditions, and the concerted R&D is also needed.

The OffshoreGrid project pointed out that every new interconnector will have a negative impact on existing interconnectors, because it will reduce the price difference between countries. The project assumed that the offshore grid would be built step by step, in which case every new generation unit, interconnection cable, political decision or economical parameter will seriously impact both the future and existing projects, in turn influencing the design of the future offshore grid. In a top-down approach, future development would be planned ahead, thus reducing the uncertainties for potential investors in generation or transmission. The top-down transmission planning approach would be especially beneficial in the context of offshore grid design.

SusPlan

The SusPlan project seems to be the only one that has published detailed cross-border transmission investment needs up to 2050. However, the results are only as good as the assumptions and the methodologies employed. Planning of European-wide power systems is by necessity an enormous modelling exercise and some shortcuts need to be taken. Some of the shortcuts in the SusPlan project are too severe and the results currently available are not good enough to set long-term transmission priorities.

The time series data for wind power seem to be based on ReAnalysis data [SusPlan, p. 38], using one point for each country plus a separate point for offshore wind. The six-hourly data from one point per country are a poor reflection of actual generation from large scale wind generation, which spans over the whole country. Solar generation seems to use data without the impact of cloud cover [Susplan, p. 145]. Furthermore, load profiles are from 2008 and wind time series from 2004, which means that the correlation between wind generation and electricity demand is lost.

Another factor affecting the quality of the results is the scenario for investments in power generation. The approach builds four different storylines and utilizes prior results (including Green-X, Primes, and EMPS) to create developments for the power generation fleet, electricity consumption, and future fuel prices. The problem is how well these results reflect the potential for managing variable generation with the different approaches described in chapter 2.1. Transmission is only one option and the others should be included in the analysis.

The model utilized in SusPlan (MTSIM) is capable of investing in new High Voltage Alternative Current (HVAC) lines. It does not make investments in new HVDC lines, which have been decided exogenously. HVDC lines are usually submarine cables used to cross seas and HVAC are overhead lines used onshore. The model appears to have assumed the same costs for all cross-border HVAC lines [SusPlan, p. 37-38], which may have a large impact on the results. In fact, the estimated investment costs for a large expansion of cross-border transmission lines are almost ten times lower than in the EC 2010 study (see below) for similar shares of variable generation.

ewi and energynautics 2011

Institute of Energy Economics at the University of Cologne (ewi) and energynautics Gmbh have combined their models by iterating between their results. Energynautics has a European grid model with 224 nodes representing generation and load centers. EWI runs a European Investment and Dispatch Model for Electricity Markets, which makes cost-effective investments in generation and transmission capacity over the modelling period. These models have been run with chronology, albeit only four typical days to present a year. Methodologically the approach is good and gives the most reliable long-term vision so far. However, the data should be improved: length of the chronology is too short, data considering wind power potential and cost in different regions is not too accurate, and there is only one scenario for investment costs and fuel prices.

The report recommends several transmission reinforcement areas: The Iberian peninsula should be more connected to central Europe through France. A North Sea offshore grid should be developed. Great Britain needs support from central Europe in addition to connections through the North Sea offshore grid. Eastern Europe and the Balkans will need additional transfer capacity. The access to the hydro resources in the Nordic countries should be improved.

EC 2008

EC 2008 used modelling tools not well suited for analysing large penetrations of variable renewables. A review of wind and solar integration studies highlights the importance of time series in at least hourly resolution, which should cover a full year, preferably from several years to capture the economic impact of variability and uncertainty [Holttinen et al. 2009]. This is especially important for analysing the benefits of transmission lines, as the utilisation and value of those lines will be highly dependent on the cross-correlations in the variable generation across countries and regions.

As discussed in 2.4.1, two large studies implemented in the US would serve as a better model for studying the impact of variable generation in large-scale systems [EWITS and WWSIS], although even they are considered as preliminary.

EC 2010

[EC 2010b] used suitable tools to analyse the operational costs of the power system and optimal transmission investments to support the assumed generation fleet. However, the scenarios for the generation fleet are based on the results of the PRIMES model, which does not take into account the fluctuations in variable generation. This leads to a bias in the generation fleet investments, which depends on the way of simplifying variable generation and which is not apparent from the PRIMES documentation. Furthermore and more importantly, the model does not capture the capabilities of the other options to mitigate variable generation noted in chapter 2.1. As a result of this bias, the later analysis in the EC 2010 has an unknown uncertainty concerning the priority transmission investments. The EC 2010 report states that the results should be used cautiously, as they heavily depend on certain simplifying assumptions, and that the lack of demand flexibility in the modelling approach makes the results conservative [EC 2010b, p. 96]. Furthermore, the report does not explain how the time series for wind and solar electricity have been created and how well they would represent large scale generation. Even if the impact of the bias were to be moderate, the report does not detail the capacities of transmission lines between countries.

ENTSO-E MoDPEHS

ENTSO-E has started a Study Roadmap towards Modular Development Plan on pan-European Electricity Highways System (MoDPEHS), which intends to find a long-term strategic plan for building and developing sequentially the European power transmission system up to 2050. A draft work programme was published in May 2011. ENTSO-E will deliver the final MoDPEHS report by the end of 2014. [MoDPEHS]

It can be expected [TYNDP 2010 p. 156-157] that MoDPEHS will take into account the possibility of a supergrid in which extra high voltage transmission is built to help large distance transfers. So far, the scenarios for a European supergrid have been based on conceptual drafts [DeserTec, Friends of the Supergrid] or preliminary analysis [Czisch and Giebel 2007]. However, the report by [ewi and energynautics 2011] takes a step forward, but even that should be repeated with much higher computational effort and rigorous data collection.

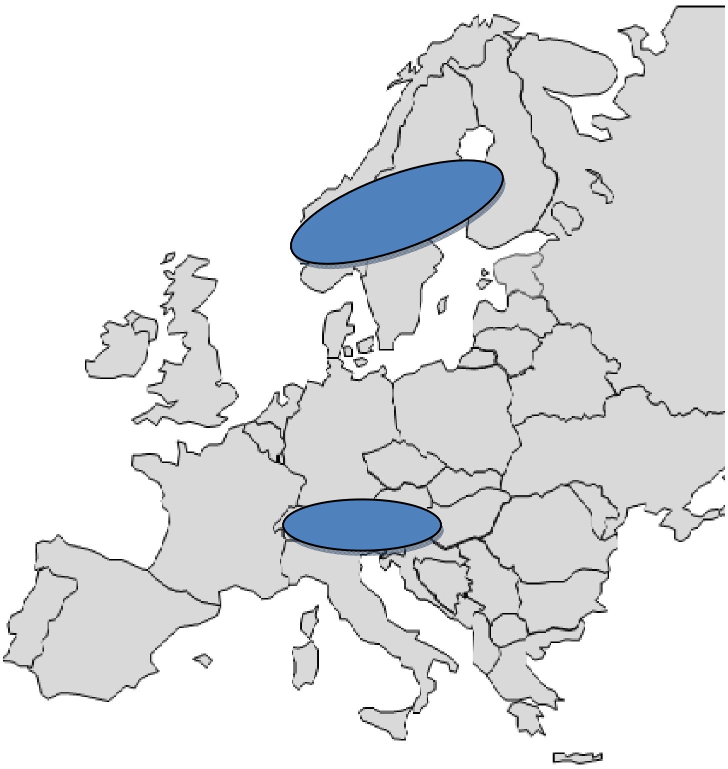
ANNEX 2: DESCRIPTION OF ENERGY STORAGE OPTIONS

Pumped hydro and compressed air energy storage

Pumped hydro and compressed air energy storage (CAES) have high storage capacities and can be used for system stabilisation, i.e. as power storage. Both technologies are most suited for daily storage as they load during hours of low electricity demand and generate electricity at times of high demand.

CAES storage has significantly lower roundtrip **efficiencies** (40%) than pumped hydro storage (75%-80%) because of natural gas use to heat the expansion of the compressed air. [BCG 2011] therefore only consider it an interim solution. Other scenarios see it as a main long term storage option [SRU 2011] when using **adiabatic** CAES (ACAES) where the compression heat is stored and the external energy input can thus be avoided. With ACAES, round-trip efficiencies may reach up to 70%. As heat storage is part of the process, ACAES is only efficient when the energy is stored over a short period, i.e. over several hours up to one day.

Map 9: Major pumped hydro storage potentials in Europe



Source: own graphic [Munthe 2011]

The main disadvantage of pumped storage is its special site requirements – water and height. The biggest **potential** in Europe is therefore in the Alps and in Scandinavia, especially Norway as shown in Map 9. Despite high technical potentials, only one pumped storage plant exists so far in Norway and there is some doubt on whether the country will be able to fulfil its role as a "battery for Europe" in the future for ecological reasons and reasons of morphological stability under fast change-rates of the water table [Heineman 2011].

Furthermore, Norway is situated far away from most European centres of electricity demand, thus creating high transportation needs to exploit this potential. Both Norway (15-20 GW) and Switzerland (4 GW) are planning to increase their pumped hydro capacities [RGI 2011]. However, pumped hydro generally is well developed in the EU and additional potentials are limited vis-à-vis RES capacities in the long term. According to Member States National Renewable Energy Action Plans, there will be some 290 GW of installed capacity from photovoltaics, onshore and offshore wind power plants in Europe in order to fulfil the 2020 target.

Hydrogen and methane

Hydrogen (H_2) and methane ("SNG", CH_4) are options for **long term energy storage**, i.e. days, even weeks. Excess electricity is used to produce hydrogen from water; depending on the system design, the hydrogen can then be synthesised with carbon dioxide (CO_2) to form methane. Both hydrogen and methane can be used as fuels to provide electricity in times of high power demand or when the renewable electricity supply is not sufficient, e.g. in the case of cloudy conditions and an anticyclone reducing wind output across Europe for several days.

The main disadvantage of both storage options is the low roundtrip **efficiency** when hydrogen (40%) and methane (27%-35%) are produced and then re-electrified. The main advantages are the flexibility in terms of energy use (**synergies** with other energy sectors). Hydrogen and SNG can also be used as **transport fuels**. Both have the potential for storing large volumes of electricity over a long period of time. Several projects for producing hydrogen and methane from wind energy are currently underway in Germany, sponsored by diverse actors as Greenpeace, Enertrag and Audi.

Apart from energy storage on system level, it is also possible to store energy at household level, wind turbine or wind park level, e.g. in batteries systems of different size and technology (**decentralised storage**). Such storage applications are connected to the transmission grid at lower voltage levels, or to the distribution grid. Among the above described storage options, hydrogen and methane storage can also be used on a wind park level. Decentralised storage would also be the typical size for a combination of a hydrogen refuelling station with demand response of the electrolyser and re-electrification of hydrogen for power balancing.

Batteries

Batteries have very different characteristics, both as such and when compared to other energy storage means. What all batteries have in common is that they allow for very fast response times in the charging and discharging process. Furthermore, battery efficiency is high even under part load conditions. These features make batteries a sound **option to provide power quality and grid balancing in the minutes up to many hours range**. To this end, batteries are generally used (or are being considered for the future) in a wide range of installed power capacities, i.e. from less than 1 kW to up to three-digit MW scale, depending on the specific battery characteristics.

Among the different battery technologies, there are significant differences with regard to **operating parameters**, such as lifetime, depth of discharge, self-discharge, operating temperatures, power density, energy density, cost per installed power/energy capacity, maintenance needs, etc. For stationary electricity storage applications, the following battery technologies are typically considered: lead-acid, lithium-ion, sodium-type and redox-flow batteries.

Sodium-type and redox-flow batteries require high temperature for operation and are thus most suited for larger scale storage with fast response times and – above all – many cycles. With storage cycling longer than 1 day, the energy needed for holding the operating temperature becomes relevant. Sodium-sulphur batteries operate at 270-350°C. They have a long duration with regard to both numbers of cycles and overall lifetime.

Redox-flow batteries (e.g. vanadium-vanadium, zinc-bromine) allow for a more independent configuration of installed power versus energy storage capacity, which brings them somewhat closer to energy storage in a fuel. With all other battery types, design flexibility is very much limited. Redox-flow batteries also have a long lifetime.

Lithium-type batteries (Li-ion, Li-air, etc.) are commercially offered for use at all power scales. Their overall lifetime is typically 20 years. They are rather costly because lithium resources are limited.

Lead-acid batteries have been used for some 100 years as a solution for grid balancing, load-levelling and backup power. They may not be as sophisticated as the newer battery technologies, but they are relatively cheap. Their overall lifetime is typically between 6 to 12 years, or some 2,000 cycles with depth of discharge of 80%, i.e. discharges are never below 20% of installed capacity.

When discussing batteries as a means for short term electricity storage, end-of-life use of **traction batteries** from battery-electric vehicles (BEV) is another option currently being discussed. Stakeholders foster this idea in order to improve the battery economics of BEVs ("**2nd Life"**) and to increase resource utility ("**cascade use"**). Cost and technology performance requirements for traction batteries are very demanding to serve BEV user needs, but battery performance deteriorates over time. Thus, battery packs could be further used (and economically valorised) in technically less demanding applications, such as stationary electricity storage. To this end, car makers like GM (Chevy Volt, Opel Ampera) and Renault (Nissan Leaf) are pursuing such concepts in industrial alliances with ABB and Sumitomo respectively. Toyota (Prius) is targeting the recycling of used batteries [Wang 2011].

ANNEX 3: DETAILED DISCUSSION OF THE BENEFITS AND COSTS OF RES BASED SYSTEMS

Benefits resulting from the integration of RES-based systems

Among these **benefits** are:

- Infrastructure reinforcements can lower **system operation costs** because they allow dispatching modern, more efficient generators in one area instead of older, less efficient units in another. Plants with very high production costs do not need to be operated whenever lower cost units in another country can supply the needed power. Thus, for example, a well-integrated pan-European market is better able to take advantage of the differences in the timing of inflows to hydro reservoirs, and therefore in the cycle of management of these reservoirs, across the continent. Likewise, relatively cheap base-load power plants can be operated for longer if enough storage capacity is available;

- **Competition** among power producers is also necessarily stronger in a larger regional market than in national markets, given the greater number of potential producers. This enhanced competition should drive end user prices down, thereby sharing with demand at least part of the increase in the net social benefit resulting from greater efficiency. Likewise, electricity storage can provide additional competitive pressure during peak-load conditions, as it can be used to effectively "shift" part of the peak-hour demand to valley-hours;

- **Supply security** increases in an integrated market thanks to the diversification of the available sources of primary energy (or the cost of providing a certain supply security level may decrease). Resource sharing lowers the risks associated with the shortage of any given fuel or spiralling prices. The wider range of potential sources of primary energy also reduces the overall dependence on third countries. However, this may probably be accompanied by the need for a tighter coordination of the operation of national systems;

- Assuming a certain degree of coordination among the control areas, the **integrated market** should be more robust than national systems in terms of primary, secondary and tertiary reserves that can be shared. According to most future energy scenarios discussed in the literature, at least 30-40% of the total electricity supply will come from large central power stations, see [Greenpeace and EREC 2010]. Coordination of the operation of the different control areas should then allow fewer and more efficient generation units to provide system reserves to other areas, which should also lead to substantial savings. The total amount of reserves to be booked by system operators and that of installed generation capacity needed could be reduced by fully exploiting the lack of simultaneity among peak load situations in different areas. The same generation units could contribute reserves in several systems at different times, by taking advantage of the lack of simultaneity of peak loads. This advantage is particularly relevant in a massive renewable energy penetration scenario, as meeting reserve and balancing technical requirements is more difficult if a significant part of the generation is of a variable nature;

- In addition, a larger number of potential electricity suppliers and the consequently increasing competition may induce a more active **demand side participation** in the market, thanks to the reduction of the market power level held by any supplier. This can result in new opportunities for consumers to reduce their bill by changing supplier.

At the same time, existing and new suppliers would have the opportunity to provide a wider range of services and increase the efficiency of the services that they already provide if they manage to increase the amount of demand they serve by supplying load in several national markets;

- Similarly, a more integrated system should allow a more efficient use of **energy storage** facilities (for instance, using pumping hydro stations in one sub-system to store surplus RES energy in another one);
- Finally, for the fraction of load centrally served, a larger market can accommodate larger and more efficient **generators** that would not otherwise be profitable in a smaller national system.

Costs of the integration of RES-based systems and barriers to overcome

A list of **socio-political and institutional challenges** faced by RES infrastructure investment projects in general, and transmission ones in particular, is provided below:

- Despite the efforts towards an integrated European **electricity market**, each national market is regulated rather differently by the EU Member States [EP-ITRE 2010]. National authorities seem reluctant to lose part of the control exerted over their respective national markets, a development that is nonetheless a pre-requisite for the efficient operation of a pan-European system;
- **Security of supply** is considered to be dealt with mostly by national authorities, according to the subsidiarity principle. The uncoordinated pursuit of security of supply can, however, lead to an inefficient development of generation and demand resources, as well as to difficulties in developing compatible regulations and trading;
- As mentioned earlier, the **technical problems** involved in the interconnection of several power systems tend to intensify, since the rising number and volume of transactions between parties from different areas is normally the outcome of bilateral or multilateral agreements among market agents with access to the entire regional grid. Such technical problems include the need for inter-country cooperation to keep the frequency stable throughout the region; ways to ensure that control areas respect the scheduled power exchanges; and the need for systems to come to one another's aid when local generation shortages arise, or when stability problems threaten the system's overall integrity. It should be stressed that such an aid will rarely come without cost or risk. On the other hand, European system operators have a long history of cooperation in solving many of these technical issues in the traditional, simpler setting of vertically integrated utilities;
- The integration of different local markets creates new challenges. The opening of national markets to **international transactions** makes transmission network management and development more complex. It may be readily concluded from the foregoing that the existing interconnection capacity is not presently able to cope with the flows stemming from all the economically and environmentally efficient transactions that should take place among agents in the region. Thus, a regulatory paradigm for grid expansion must be implemented to yield optimal, or at least sufficient, European grid development. Given the lack of interconnection capacity between areas, efficient market-based mechanisms must be established to allocate the scarce transmission capacity available for regional transactions.

Furthermore, with the intensified use of local transmission grids for international transactions, control areas' demands for compensation for such use, or for the benefit accruing to international agents as a result of such use, can be expected to intensify as well;

- The technical complexity of the regional network within the Integration of Electricity Markets (IEM) may increase substantially, at least in the medium to long term future, due to the use of innovative technologies like large HVDC overlays. A European "**overlay grid**" (also titled "supergrid" or "electricity backbone") of meshed HVAC and/or HVDC lines is discussed for bulk power exchanges over large distances beyond the current UCTE/ENTSO-E capacities. Especially HVDC seems to be promising to this purpose, as it allows a loose coupling of big grids, thus maintaining or even increasing (black-start capability) the overall system stability and resilience. Technical issues in controlling meshed HVDC grids – e.g. high-power DC switchgear – are currently being investigated. Such an "overlay" transmission grid may even include interconnections with EU neighbouring countries, e.g. in the Middle East/North Africa (MENA) region. Interconnections may serve EU market integration, provide a development perspective and increase mutual energy supply security of the EU and its neighbours;
- Furthermore, if Europe is to build a fair and efficient market, it must ensure a level playing field where market agents compete on equal terms. The lack of **regulatory harmonisation** among the systems involved constitutes a sizeable challenge in this regard. One example is the structure of the network charges applied by each country, especially with regard to the differences in their application to generators and consumers. The fact that some countries include in the charges regulated costs that are unrelated to the network is an additional source of complexity. All these factors are clear obstacles to market integration. Surmounting such barriers calls for substantial harmonisation;
- Last but not least, successful infrastructure building must enjoy the required **public support**, both from the public at large and from the people more directly affected by each specific infrastructure. For instance, the construction of new power lines has been opposed by local populations, often arguing that it could have damaging effects on the environment. However, massive renewable energy penetration calls for significant building of new infrastructures. Measures like syndicated financing with participation from local investors, as well as remuneration schemes that allow for fair local added value, may increase local acceptance. The benefits here would be local acceptance and the participation of local parties in the sharing of benefits yielded by regional infrastructure investments.

Non-economic costs and benefits (and even some of the purely economic ones) **are notoriously difficult to value**, so most of the quantitative studies on this subject available in the literature refer to the purely economic benefits. Because of the huge disparity in costs between transmission on the one hand, and generation and distribution on the other (transmission costs being relatively smaller), these studies normally take the form of generation-transmission analyses in which the transmission development is contingent on the previously decided generation and demand future development path.

ANNEX 4: COST BENEFIT STUDIES

Transmission

A brief description of some main analyses found within the literature follows:

EWIS [European Wind Integration Study]: benefits of the installation of **150 GW of wind generation capacity** and the construction of the associated grid infrastructure would outweigh costs. A reduction of between 2.1 and 3.8 €/MWh in wholesale prices in Europe in the year 2015 would be achieved;

Enhancing **interconnection capacities in Europe (29 most relevant projects)** in this same time horizon would result in an increase in power exchanges from 613 to 844 TWh annually. Total **benefits from reinforcements equal €1.92bn annually**. Within these, annual benefits stemming from the further integration of wind generation amount to €357bn, representing a decrease in operation costs. The rest is due to other factors. Of these, the benefit associated with the resulting reduction in wind integration costs would amount to €0.174bn annually. The cost of these reinforcements would amount to €0.896bn annually. For more information, see [Winter 2010];

EDF-Interconnection capacities: this study makes an estimate of the electricity system costs and benefits in the **year 2025**, resulting from the construction of those reinforcements to interconnection capacities among countries in Western Europe proposed within the **ENTSO-E TYNDP**. The overall increase in interconnection capacity amounts to 7 GW overall. Costs of reinforcements have been computed as those of the priority interconnection projects, multiplied by an augmenting factor to account for the reinforcements to the national grids that should be associated with the corresponding interconnection projects. Benefits considered include the decrease in generation investments costs and operation costs resulting from the more efficient utilisation of available generation. However, authors do not consider the impact of network reinforcements on security of supply. Reductions in generation capacity needs amount to 4,000 MW of CCGT and 500 MW of peaking units. This represents a reduction in fixed generation costs of about 620 M€/year. Reductions achieved in fossil fuel usage (i.e., coal and oil) are 6 TWh/year, which represents 0.5% of the electrical fossil fuel usage. Additionally, a reduction in CO_2 emissions of 2.4 $MtCO_2$/year, or around 0.3 % of the emissions from the Western electrical industry in the Reference Scenario, was achieved. Overall reductions in variable operation costs were valued at 360 M€/year. On the other hand, costs of additional network reinforcements amounted to 380 M€/year. **Annual net benefits** were thus estimated to be **about 600 M€/year**. For more information, see [Rebours et al. 2010];

RISO-RES scenarios: In this analysis, the functioning of a **100% RES based system** is simulated under different **sets of conditions**, including one in which the EU grid is optimally developed and another in which severe restrictions are imposed on interconnection capacity, excluding cross-national electricity transport via HVDC. Equivalent total supply costs for the different regions in Europe are computed for each scenario. Average total electricity supply costs in the 100% RES unconstrained scenario is **4.7 €ct/kWh**. In this unconstrained scenario, **3.6% of electricity production is wasted**. When constraints are imposed on interconnection capacity, meaning that no future Electric Highway System (EHS) is built in Europe, wasted RES generation increases to 10% of overall production and supply costs increase to over 8 €ct/kWh on average. Assuming 2050 as the moment in which electricity supply can be based 100% on renewable generation, the demand of electricity would be about 5,200 TWh, according to the Power Choices scenario in [Eurelectric 2011] study. This means that the **reduction in supply costs** associated with deploying the EHS would **amount to €171,600 million/year**. Obviously, according to this study, and envisaging a 100% renewable future, building the EHS would make perfect sense from an economic point of view. For more information, see [Czisch and Giebel 2003];

Tradewind: This analysis assesses the benefits produced by on-shore interconnection capacity as well as off-shore network reinforcements required to build a **meshed grid in the North Sea** to connect local wind generation to the main inland grid. The time horizon of the study is **2020-2030** and the benefits considered are the reduction in the overall system operation costs and the contribution of transmission capacity to the capacity credit of wind. On-shore interconnection reinforcements considered are the 42 most valuable ones among those not yet planned in the year 2010 (these reinforcements would be distributed along the period 2015 to 2030). Results show that in the years **2015 and 2020** proposed reinforcements are not believed to be necessary, since the expected resulting **reduction in supply costs is small** (0.03 €/MWh in 2015 and 0.07 €/MWh in 2020) compared to the cost of the reinforcements, because the increase in load more or less matches the increase in wind generation. On the other hand, extra reinforcements proposed to have been built by **2030** would result in much **larger benefits** in this year. Thus, in the year 2030 the **reduction in supply costs** resulting from extra reinforcements beyond those already planned would be **€870 M/year** for the first set of reinforcements (or 0.19 €/MWh) and **€1500 M/year** (or 0.32 €/MWh) for the set of most ambitious reinforcements. This clearly surpasses the cost of building the reinforcements, which amounts to €490M for each of the 42 proposed. Besides, the reinforcements to interconnections would allow **doubling the capacity credit** of the 200 GW **of wind generation** expected to be installed in 2020, thus reaching 14%, or 27 GW. For more information, see [EC 2009];

TYNDP, analysis for the **South-West region**: a cost-benefit analysis of the reinforcement of the interconnections among Portugal, Spain and France and associated national lines was carried out. Reinforcements considered are those in the national expansion plans 2007-2018, which amount to about 2000 MW of cross-border capacity between Spain and Portugal and another 2000 MW between Spain and France. The **cost** of these reinforcements is **€300M** for the border between Portugal and Spain and **€850M** for the border between Spain and France. The level of expected energy not supplied decreases by around 14 GWh/year with the planned development of interconnections. This improved Security of Supply (SoS) mainly benefits France. Besides, interconnection capacity would result in an increase of RES electricity production in the region by 1 TWh annually. Reduction in CO_2 emissions due to new interconnections would be about 2-3 Mtons annually. Finally, this interconnection capacity would avoid 7 TWh of energy re-dispatch per year, which could represent a decrease in operation costs of about **€70-140 M/year**, see [ENTSO-E 2010];

TYNDP, analysis of the **Savoy-Piedmont HVDC** project between France and Italy: the results of a cost benefit analysis for a **1000 MW cable** between Savoy and Piedmont are provided as an example of a specific interconnection project. This line could allow the export of about 5 TWh/year more energy from France to Italy, which would result in a **reduction in operation costs** of several hundred million euros per year. Besides, a reduction in CO_2 emissions would take place of between 1.5 and 2.5 Mtons per year. See [ENTSO-E 2010];

Supergrids and CSP: this analysis explores the possibility of supplying large amounts of electricity demand in Europe with **renewable generation located in Northern Africa** when a supergrid linking these outer areas to main load centres in Europe is built. According to the analysis, this could make economic sense in the **medium to long term future**, when CO2 emission reduction objectives become highly restrictive. The authors carry out a cost-benefit analysis of the installation of CSP generation capacity in the MENA region (Middle East and North Africa). CSP generation installed is primarily used to supply local load. However, from the year **2045** on, if climate policy constraints are applied to the production of electricity in Europe, importing from the MENA region part of its CSP based electricity production makes economic sense. Exports from the MENA region to Europe should increase with time, and would mainly depend on the kind of policy constraints imposed on CO_2 emissions and conventional electricity production (CCS and nuclear). Thus, the transmission capacity necessary to export this energy ranges from **10 GW in the year 2045**, for the case in which GHG concentration is forced to get stable and no more CCS operations are allowed, to more than **900 GW in the year 2100** if GHG concentration is to be stabilised, nuclear power capacity must be limited to 2005 levels and no CCS operations are allowed. In any case, investments in the **supergrid infrastructure** would range between 1 and 9% of the total investment needs (generation and transmission). Transmission investments therefore amount to between a few billion dollars ($1-3 billion) and about $25 billion in the case in which the largest exports are justified. CSP energy exported to Europe would range between 50-100 TWh/year for the least ambitious interconnection project and almost 3,500 TWh/year in the year 2100, when policy constraints on electricity production are most restrictive. The market value of these exports would range between a few billion $ and $375 billion, or **1.80% of total GDP in the MENA region in the year 2100**. CSP production exported to Europe would replace CCS and, if necessary, nuclear production (whenever nuclear production is restricted, about 60% of non-RES production replaced would be nuclear), see [FEEM 2011];

Offshore grid project: in this analysis, the costs and benefits of developing an **offshore grid in the North Sea** are calculated. According to the authors, the offshore grids to be developed should be interconnected, including connections between countries. If hubs, instead of a radial grid, are developed within each country's offshore network, costs would be reduced from €83 to €69bn. This alone would result in benefits breaking even with costs (otherwise, costs would be larger). However, if additionally interconnections are built between the offshore grids of the different countries, then extra **costs of €5-8bn would be more than outweighed by benefits**, which would amount to between €16 and €21bn, depending on whether a split grid design or a direct grid design is undertaken. For more information on this analysis, see [De Decker et al. 2011].

Hydrogen fuel cell electric vehicles, which are currently operated in small fleets for market preparation, are scheduled to be commercially available in Europe starting from 2014. An early study by the HyWays project analysed costs and benefits of the introduction of FCEVs in Europe [HyWays 2008]. Various policy support scenarios have been analzed from "modest policy support" to "very high policy support" with modest and fast technical learning curves. These lead to different vehicle penetration rates and vehicle populations over time based on 10 EU reference countries for EU-15. Modest policy support and modest learning curves lead to 0.1 million vehicles in 2020 and 5 million vehicles in 2030. High policy support leads 1 million and 15 million vehicles in 202 and 2030, respectively, and very high policy support to 5 million and 50 million vehicles in 2020 and 2030, respectively. Policy support is notably required for the build-up of a hydrogen refuelling infrastructure, initial competitive pricing of hydrogen fuel and R&D and market introduction support. In the different scenarios, some 900 refueling stations will be required by 2015, between 13,000 and 20,000 in the mid to long-term. **Detailed costs analyses** indicate that for a total hydrogen passenger car system about 15%-20% of total necessary investment goes into hydrogen production/transport/distribution/refueling, around 20% into the hydrogen-specific technologies on-board the vehicle (fuel cell, hydrogen storage, etc.), and 60% for the conventional part of the vehicle. Economic benefits were calculated including **net employment effects**. In the high policy support scenario, up to 500,000 net jobs may be created or lost in Europe, depending on the international competition from the Americas and Asia.

A recent study **compares battery electric vehicles (BEV), plug-in hybrids (PHEV) and fuel cell electric vehicles (FCEV) in terms of performance, costs, infrastructure requirements, market segments and required investments** [Coalition 2010]. In order to identify a balanced scenario for the electrification of passenger cars in the EU up to 2050, a combined forecasting and backcasting approach was used: from 2010 to 2020, global cost and performance data were forecasted, based on proprietary industry data; after 2020, on projected learning rates. In order to test the sensitivity of these data to a broad range of market outcomes, three European "worlds" for 2050 were defined, assuming various power-train penetrations in 2050. These scenarios include total electric vehicle shares of 15%-30% by 2030 with varying individual shares of BEVs, PHEVs and FCEVs. The study concludes: "PHEVs are more economic than BEVs and FCEVs in the short term. All electric vehicles are viable alternatives to ICEs by 2025, with BEVs suited to smaller cars and shorter trips, FCEVs for medium/larger cars and longer trips. With tax incentives, BEVs and FCEVs could be cost-competitive with ICEs as early as 2020." According to the study, the conclusions are robust to significant variations in learning rates for the power-trains and the cost of fossil fuels.

Storage

Storage facilities can substitute some network development. They can be located close to the load (see e.g. [Walawalkar, Apt and Mancini 2007] for an analysis of possible storage facilities in New York City), or close to the generation. In the case of variable generation, storage onsite/near the supply source can lower transmission expansion costs as the line rating does not need to match maximum but average power. These sorts of facilities can be very interesting in systems where renewable sources are far from the consumption centres, although it does not seem so relevant in the **EU context**, where renewable sources are inside an already highly meshed system or in areas where storage is extremely expensive or not feasible (e.g. offshore wind). In [Hoogwijk et al. 2007], the costs of integration of wind and PV generation are derived for OECD Europe, both including and excluding transmission costs. According to the authors of the latter work, the impact of the construction of transmission infrastructure on total integration costs is much lower than that of other integration cost components. **Concentrating Solar Power** plants are exceptional in this regard. Be they planned in Southern Europe or in Northern Africa, it is generally assumed that they come with a **sizeable thermal storage capacity** (e.g. 7 full-load hours in the CSP report quoted above). For this kind of facility, storage can be up to 40% of the total overnight investment cost (see [Trieb at al. 2009]).

Storage devices can be jointly operated with renewable generators even if they are not located in particularly close geographical locations. There are a number of studies valuing this policy (e.g. [Garcia-Gonzalez at al. 2008]), although they do not address system-wide costs or benefits. Results based on very general assumptions are derived in [Rasmussen 2011], which concludes that in a pure **combined wind-storage system** the storage requirement "for significant availability improvement in a given period, is found to be 20 to 40% of the energy produced in the period and 80 to 100% of the average power for the period".

In most systems, the most efficient use of storage facilities should be made by **integrating their operation in the wider power system**. [Swider 2007] analyses the value of investments in **CAES facilities in the German system**. The study covers the period up to 2020. It is concluded that CAES investment partly displaces mainly flexible generation (gas turbines), whereas load-base power plants (coal and lignite) are almost not affected.

CAES integration results in system savings equivalent to reducing between 0.15 and more than 2 €/MWh the cost of wind based electricity. The figure depends on the assumed values of different parameters.

[Black and Strbac 2007] assess bulk storage value in a **future UK system** with 26 GW of installed wind generation capacity (20% of generated electricity). They find that the value considerably depends on the amount of flexible generation like gas turbines (from 179-252 £/kW of storage in a flexible system to 619-968 £/kW in an inflexible one). Qualitatively similar results are provided in [Milligan et al. 2009] for a **simplified Western US model**. The value of storage ranges from 1,100 to 1,600 $/kW for the current energy mix, and from 1,100 to 1,200 $/kW for a more flexible one when wind penetration increases from 0 to 40%. **Wind spillage** without storage facilities is negligible, below 20% of wind penetration.

[Salgi and Lund, 2006] analyse the possible role of **Compressed Air Energy Storage in Denmark** to facilitate higher penetration of wind generation, up to and over 55% assuming constraints to export energy outside. They find that under 55% wind penetration, wind spillage can be optimally suppressed by CAES system with capacity 2700 MW and 500 GWh, assuming no traditional power plants in the system. Figures are considered unrealistically high, so it is concluded that "CAES alone is not able to eliminate excess production".

Poyry's NEWSIS study [NEWSIS 2011] finds that storage gross profit could more than double from now to 2035 as a consequence of greater intermittent generation penetration and price volatility. However, it also concludes that "(given current efficiency and capital costs) grid-scale energy storage for wholesale market balancing is **[mostly] not economically viable**".

TradeWind simulates the use of **pumped hydro in 2020 and 2030**, assuming capacity remains constant at 31.4 GW. It is found that it increases from 14.1-15.9 TWh in 2020 to 21.4 to 29 TWh in 2030 as wind generation increases from 419.5-420.4 TWh to 561.2-562.7 TWh. The differences are due to the lesser or greater flexibility to re-schedule units and international trades, being greater pumping use associated to less flexibility.

EWIS analyses the impact of congestion of the **planned increase in pump capacity in Switzerland** from presently 1.6 GW to 4-5 GW in the future. It finds that congestion between Germany and Switzerland, as well as between Germany and Austria, becomes more acute as a consequence of greater Swiss imports of German wind electricity. As imports become correlated with wind production, so will be the ensuing congestion rents, although no figures are provided.

RESPOND aims were to "identify efficient market response options that actively contribute to an efficient integration of (intermittent) RES-E and DG". It concludes by recommending electricity storage as **existing pumped hydro**, regulating existing reservoirs of existing hydro plants, **hydrogen-fuel cell storage if economically viable in 2015-20**, and **flywheels** and **lead-acid batteries for power quality services**. Eventually, "given high wind-penetration of highly variable electricity and a suitable location, **compressed air storage systems** can be used". However, recommendations are not backed by quantitative estimates.

Electric mobility

Authors in [EPRI 2011] define three different **EV penetration scenarios for the USA** and compute future social benefits and costs of EVs in the period 2015-2030.

The number of vehicles considered range between 3.1 and 12 million in the year 2020 (5.8 million in the medium penetration scenario) and between 15 and 65 million in the year 2030 (35 million in the medium penetration scenario). In relative terms, penetration levels range from 1 to 3.9% of the total amount of cars in the year 2020 and between 4 and 17.7% of all cars in the year 2030.

According to this analysis, **annual reductions in gasoline consumption in the USA** resulting from the use of EVs could range between 770 million gallons and 2.9 billion gallons in the year 2020, and between 3 billion gallons and 13 billion gallons in the year 2030 (medium penetration levels correspond to savings of 7 billion gallons). In return, electricity consumption would rise between 8.8 and 33 TWh in the year 2020 (16 TWh in the medium penetration scenario) and between 32 and 150 TWh in the year 2030 (80 TWh in the medium penetration scenario). As a result of this, overall CO_2 emissions would decrease. Using the current CO_2 emitted by US-average electricity production, annual reductions in emissions achieved in the medium penetration scenario would be 2.1 million metric tons of CO_2 in the year 2015 and 48 million metric tons in the year 2030, which represent 0.038% and 0.8% of total CO_2 emissions in the US in the year 2008. Therefore, the impact of EVs on emissions would be limited but non-negligible in the long run. Taking into account the fact that electricity is on average a much cheaper transport fuel than gasoline (between 3 and 4 times cheaper), and considering a cost for electricity of 1 dollar/equivalent oil gallon, the reduction in fuel costs would amount to between 3 and $4.5 billion in the year 2020 and between 14 and $21 billion in the year 2030 for the medium EV penetration scenario. Fuel costs within the power sector would increase by $1.5 billion in the year 2020 and $7 billion in the year 2030.

As for electricity infrastructure, authors in (EPRI, 2011) argue that, for the penetration levels considered in their study, the increase in the corresponding costs could be deemed negligible if EVs can be charged in a smart way. Otherwise, a significant fraction of old assets (cables and transformers) would experience overloads and would probably have to be replaced. The cost of developing the required technology to **make EVs cost competitive in the market is not estimated**.

[Karnama 2009] performs a technical analysis of different scenarios of **plug-in hybrid electric vehicles in the Stockholm area**. He concludes than even in the case of 100% PHEV penetration, no significant re-enforcements in the distribution network are required so long as the PHEV are **charged in a smart way**. On the other hand, if drivers charge their cars as soon as they get home, the distribution network may need to be upgraded to handle over a 30% of peak load which is the main determinant of the investment level.

A comprehensive study of electric vehicles penetration is performed in [G4V 2011]. It concludes that benefits of EV integration start appearing even at low penetration, and that smart charging enhances the system ability to absorb a large share of intermittent energy (e.g. wind spillage decrease from 8 to 2.5% when EV penetration grows from 0 to 10% in a German system simulation, marginal decrease if charging is not smart). Additional benefits from **vehicle to grid energy flows are found to be marginal**. It is also found that smart strategies can postpone reinforcements for considerable penetration levels. Specific **charging stations** add a cost ranging from €850 to €9,200 per vehicle, as a function of the average daily use.

Supply side management

[Tzimas et al. 2009] analyse the evolution of the **European fossil fuel plants until 2030**. They consider high and low carbon prices scenarios, as well as a BAU and a low carbon policy scenario. It is found that gas turbines investments range from 19% to 34% of new generation investments, with additional investments in combined cycle gas turbines (CCGT). Investments in gas turbines are greater in the low carbon scenario.

Poyry's NEWSIS study [NEWSIS 2011] finds that **thermal plants become "intermittent"** in their operation. Specifically, by 2030, "the French system still has a lot of nuclear generation, and the balancing of the wind is achieved via a combination of flexing the nuclear plant along with imports and exports. In GB during the winter months, the thermal plants have much lower load factors than in 2010, and operate in response to wind generation."

Even if these operations are feasible, they imply costs that are not publicly available. For instance, [IER 2009] reports on the operational flexibility of nuclear power plants. However, more frequent cycling typically increases the **maintenance costs**, the **forced outage rate** and hence the resulting electricity costs; it also typically decreases the **plant life**. It is known that the costs of cycling can have high variation between different power plants, even if they are seemingly similar. **Trade-offs between flexibility and storage** are discussed e.g. in [Swider 2007] and [Black and Strbac 2007].

NOTES

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