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# ***IMPACT ASSESSMENT***

***Accompanying document to the***

**COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS**

**Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network**

{COM(2010) 677 final}
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# GLOSSARY

| | |
|---|---|
| AC | Alternating Current |
| ACER | Agency for the Cooperation of Energy Regulators |
| BAU | Business As Usual |
| BEMIP | Baltic Energy Market Interconnection Plan |
| CCS | Carbon Capture and Storage |
| CNG | Compressed Natural Gas |
| CRE | Commission de Régulation de l'Energie (National Regulatory Authority in France) |
| DC | Direct Current |
| EBRD | European Bank for Reconstruction and Development |
| EIA | Environmental Impact Assessment |
| EEPR | European Energy Plan for Recovery |
| EESII | European Energy Security and Infrastructure Instrument |
| EIB | European Investment Bank |
| EIP | Energy Infrastructure Package |
| ENPI | European Neighbourhood and Partnership Instrument |
| ENTSO-E | European Network of Transmission System Operators in Electricity |
| ENTSOG | European Network of Transmission System Operators in Gas |
| ERGEG | European Regulators' Group for Electricity and Gas |
| ETS | Emission Trading Scheme |
| EU | European Union |
| GDP | Gross Domestic Product |
| GW | Giga Watt |
| ICT | Information and Communication Technology |
| INOGATE | European Union programme supporting international cooperation between the EU, the littoral states of the Black and Caspian Seas and their neighbouring countries |
| IPA | Instrument for Pre-Accession Assistance |
| LNG | Liquefied Natural Gas |
| Mtoe | Million tons of oil equivalent |
| NGO | Non-Governmental Organisation |

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|---|---|
| NIF | Neighbourhood Investment Facility |
| NSCOGI | North Sea Countries Offshore Grid Initiative |
| OFGEM | Office of Gas and Electricity Markets (National Regulatory Authority in the UK) |
| PEI | Project of European Interest |
| RES | Renewable Energy Sources |
| SME | Small and Medium Enterprises |
| TEN-E | Trans-European Networks for Energy |
| TFEU | Treaty on the Functioning of the European Union |
| TSO | Transmission System Operators |
| TWh | Tera Watt hour |
| TYNDP | Ten-Year Network Development Plan |
| UPS | Unified Power System (synchronised power system currently covering Russia and the three Baltic States) |
| VSC | Voltage Source Converter (technology to improve overall system performance for both high voltage alternating current and direct current transmission) |

# 1. PROCEDURAL ISSUES AND CONSULTATION OF INTERESTED PARTIES

Lead DG: ENER

Services involved in the Interservice Group: AGRI, AIDCO, BEPA, BUDG, CLIMA, COMP, DEV, ECFIN, ELARG, ENTR, ENV, ESTAT, INFSO, JLS, JRC, MARE, MARKT, MOVE REGIO, RELEX, RTD, SANCO, SJ, SG, TRADE, TAXUD

Reference to Roadmap:

http://ec.europa.eu/governance/impact/planned_ia/docs/19_ener_energy_infrastructure_package_en.pdf

**Background:**

Europe's future economic growth and stability depend on the availability of appropriate energy infrastructure ensuring the achievement of the EU energy and climate goals, cost-efficient functioning of the internal energy market and security of supply. In 1996, as part of EU moves to complete the single market, the Trans-European Energy Networks (TEN-E) policy was developed. Its purpose was to provide a more political impulse to energy infrastructure development from the European perspective, by focussing on the feasibility stage for gas and electricity network projects, notably those crossing borders, which contribute to the working of the internal market. At that time, the EU had no common energy policy and no functioning internal energy market. In most Member States, state-run companies managed network investments, which were mainly driven by national security of supply considerations. Later revisions to TEN-E incorporated sustainability and supply security criteria. It was assumed throughout that EU intervention in the implementation phases of such projects would not be necessary, as commercial interests would drive projects forward. The TEN-E budget consequently remained very low – some € 22 million annually in the period 2007-2013. The currently valid TEN-E Guidelines were adopted in September 2006 replacing those of 1996[1] and 2003[2].

This impact assessment was prepared to support the forthcoming communication on energy infrastructure priorities (phase 1 of the so called "Energy Infrastructure Package") for a new policy to promote the development of TEN-E to enable adequate and timely development of energy infrastructures. This impact assessment covers the development of energy infrastructure for the period 2010-2020, with a view beyond to 2030 - having in mind the energy challenges for the century - and assesses investment needs for new transmission infrastructure, evaluates the current TEN-E framework and financing possibilities, compares various policy options for implementing sufficient infrastructure to support the achievement of the EU's energy and climate policy goals in the most cost efficient way and thereby examines the possibility of integrating CCS and oil transport networks in the future policy.

Building on the present document, a separate assessment will be carried out to prepare the legislative proposal for a new European energy security and infrastructure instrument, which is to be presented in 2011 (phase 2 of the Energy Infrastructure Package). Therefore, the present impact assessment does neither include a detailed analysis of the way, in which infrastructure investments are currently financed, nor possible solutions in terms of tariff regulation or financing to address the identified investment gap or other financing shortcomings.

The detailed list of documents and studies that have been used for the preparation of this impact assessment can be found in Annex 5.

[1] Decision No 96/391/EC
[2] Decision No 1229/2003/EC

## 1.1. Green paper and public consultation

The main consultation for this impact assessment took place in the framework of the green paper "Towards a secure, sustainable and competitive European Energy Network", which was endorsed by the European Council and Parliament and published with the Second Strategic Energy review[3]. The green paper pointed out that the current EU network policy was not able to deal with global security of supply challenges, to effectively diversify the EU's energy sources, to ensure solidarity in the case of an energy crisis or to draw on the benefit of new technologies. It also stressed the direct link between energy import infrastructure and the EU's external relations. The Green Paper recommended that energy infrastructure development should be driven by the energy policy goals: the "20-20-20" objectives[4], security of supply and solidarity, sustainability and innovation, as well as competitiveness. The implications of climate change for Europe's energy networks, concerning for example the location of power plants, electricity lines and pipelines, were identified as an important element to be taken into account for infrastructure projects. It moreover recommended:

- to extend the scope beyond electricity and gas transport infrastructures (including liquefied natural gas terminals and storage) to oil and $CO_2$ transport infrastructure;
- to let the market drive planning with a clear remit for the European Network of Transmission System Operators and the Agency for the Cooperation of Energy Regulators, as well as the EU as active facilitator and mediator;
- to narrow down the number of priorities to a limited number of European strategic projects, to be incorporated in national infrastructure plans;
- to build up accompanying measures to disseminate information and exchange best practices;
- to consider, in exceptional cases, the appointment of a European Coordinator, building on the experience of the past/current coordinators;
- to improve the effectiveness of the TEN-E instrument within existing means through better coordination with other EU financial instruments, while also considering ways of increasing the TEN-E budget, notably to support investments with a public good character.

Questions at the end of the Green Paper addressed the main barriers to the development of a European electricity and gas network and the role the EU should play in overcoming these barriers. Concerning TEN-E, the questions asked advice on the main recommendations listed above and additional measures the EU could take to secure sustainable infrastructures.

During the four month consultation exercise, ending on 31 March 2009, The Commission received 91 written replies to the questions raised in the Green Paper. 13 came from Member States (2 from a regional and a local government), 1 from regulators, 60 from the industry, 2 from academia and 13 from individual citizens, NGOs and other organisations.
The energy sector dominated the industrial responses. Contributions were received from system operators, the upstream sector, the energy equipment sector, and cogeneration and district heating companies as well as shippers, traders and firms involved in infrastructure construction. The renewable industry was mainly represented by wind and solar industry players.

A clear message from the public consultations was that there is a strong need to better align the energy network policies of the EU and the EU energy and climate targets. There was also general support for a fundamental review of the TEN-E framework. The Commission's concern to give more attention to energy infrastructure as a factor of energy security was

[3] COM (2008) 781 "An EU energy security and solidarity action plan" endorsed by the Council in its March 2009 summit conclusions
[4] 20% reduction in greenhouse gas emissions, 20% share of renewable energy in EU final energy consumption and 20% improvement in energy efficiency by 2020

also vindicated. The possibility to also cover transport infrastructure for carbon dioxide capture and storage (CCS) was generally supported, while the replies were more hesitant on oil transport networks. A specific area where a broad consensus emerged was in the relevance of energy networks to EU external energy relations. The role of the EU in facilitating infrastructure projects in third countries was welcomed, and the importance of external energy relations to infrastructure policies was reaffirmed.

## 1.2. Stakeholder consultations

Stakeholder consultation included discussions in the Gas Coordination Group[5] (March and June 2010) comprising representatives of 27 Member States and gas industry and gas consumers' associations, in the different working group meetings (Sustainable Fossil Fuel and Security of Supply working groups) of the Berlin Fossil Fuels Forum (May 2010). Regular exchange of information took place with the two European Networks of Transmission System Operators (ENTSO) for gas and for electricity and the European Regulators' Group for Electricity and Gas (ERGEG). The 10 year network development plans developed by the ENTSOs served as an important input for the infrastructure needs assessment. A high level conference was organised under the Spanish Presidency on 28 May 2010. Regarding the development of offshore grids, inputs from the so-called "Adamowitsch working group[6]" and the workshop organised by the North Seas Countries' Offshore Grid Initiative (March 2010) have been incorporated.

Several bilateral meetings with industry representatives and stakeholder organisations took place providing similar results to the public consultation. The electricity industry expressed particular concern about lengthy and uncertain permitting procedures and supported the Commission's intention to tackle those. A further concern was the need for better regulation of grid investment financing and cost sharing. The industry also pleaded for the definition of priority infrastructure corridors rather than pre-defined project lists. The gas industry generally emphasised the environmental advantages of gas in terms of lower CO2 emissions in comparison to other fossil fuels. The CCS sector was strongly in favour of the inclusion of CO2 transportation infrastructure in the trans-European networks policy, while there was no common position concerning the inclusion of oil pipelines within the oil industry (generally, Eastern EU oil companies supported the idea, while Western European companies did not have a position).

Regarding smart grids, this impact assessment has benefited from the input given by the European Technology Platform smart grids for the preparation of the Strategic Energy Technologies plan (June 2007) and by the three experts groups of the European Task Force for smart grids, which presented their intermediate reports in June 2010.

Following the recommendations for improvement included in the opinion of the Impact Assessment Board on the 27th September 2010, a better explanation is provided on the issues, which will be tackled in the forthcoming Communication and are thus included in this impact analysis, and on the issues, which would need to be further explored for the legislative proposal and its accompanying Impact Assessment, to be prepared next year. Chapters 2.3 and 3 have been amended accordingly. To provide more transparency on the underlying modelling, its assumptions and investment estimates, specific boxes have been inserted in Chapters 2.4 and 5.1. Chapter 2.4 has generally been amended to better highlight what the expected impact of the implementation of the 3rd Package on the internal energy market will be in the baseline scenario. In these chapters, the current tariff setting rules and their shortcomings as well as the definition of "commercial viability" are better explained; however, an in-depth analysis of these issues is foreseen for the IA report accompanying the

[5] Commission Decision 2006/791/EC
[6] Consultative group set-up by the EU Coordinator for off-shore wind, Mr. Georg-Wilhelm Adamowitsch

legislative proposal. Concerning the issue of permitting Chapters 4.4 and 5.5 have been amended, including clearer explanations and indications on the further analysis to be undertaken to provide a more thorough assessment of the options aiming at accelerating permitting – i.a. the assessment of the compatibility of the options with national legal systems and their costs – and included in the Impact Assessment for the legislative instrument. Finally, the options and impacts for the policy areas of coordination and design of new policy instrument have been clarified in Chapter 4.2, 4.3, 5.3 and 5.4. Following the second opinion of the Board (18th October 2010), further improvements have been included with reference to the estimates on the investment needs and in the conclusions.

## 2. PROBLEM DEFINITION

### 2.1. A dramatically changed policy context

This chapter summarises the current energy policy context which has changed dramatically since the TEN-E policy was last revised in 2006. More details on existing legislation and its impact on future infrastructure development will be given in chapter 2.4 (Baseline scenario).

The **EU Energy Policy**[7] and its implementing legislation, pursuing the objectives of sustainability, competitiveness and security of energy supply, set ambitious goals and binding targets for 2020 on greenhouse gas emissions[8] (-20%%; -30% if a satisfactory international agreement is reached), energy from renewable sources[9] (20% of final energy consumption) and energy efficiency (20% reduction in energy consumption compared to business as usual). This legislation includes the energy and climate package (Renewable energy directive[10] and CCS directive[11]), the third internal energy market package[12] and the recently agreed regulation on security of gas supply[13].

Adequate, reliable energy networks are a prerequisite to meet all these objectives. Europe's networks will have to undergo important evolutions to meet this challenge – evolving from a patchwork of national networks to a truly integrated EU-wide network. At the same time, these networks are aging and urgently need refurbishment and modernisation. Therefore, massive investments in network infrastructure will be needed in the coming decades, challenging the TEN-E policy framework as a whole and the existing regulatory model for electricity and gas infrastructure development in Europe.

The regulatory framework itself has evolved with the adoption of the third internal energy market package in July 2009. It introduces several new rules for infrastructure planning, coordination and investment, which address many of the weaknesses (detailed in chapter 2.4.2). Transmission System Operators (TSOs) are required to establish national 10-year network development plans and to co-operate and elaborate regional and European 10-year network development plans (TYNDP) for electricity and gas with a focus on cross-border interconnections, in the framework of the European Network of TSOs (ENTSO). The package also establishes an Agency for the Co-operation of Energy Regulators (ACER) that – among other tasks – will have to monitor the implementation of European TYNDPs. The

[7] COM (2007) 1 endorsed by the Council on 15 February 2007 (C/07/24)
[8] Directive 2009/29/EC amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community, Decision No 406/2009/EC on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020
[9] Directive 2009/28/EC on the promotion of the use of energy from renewable sources
[10] Directive 2009/28/EC OJ L140 of 5.06.2009 p. 16
[11] Directive 2009/31/EC establishes a legal framework for safe geological storage of carbon dioxide ($CO_2$).
[12] http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm: see notably Directives 2009/72/EC and 2009/73/EC and Regulations (EC) 713/2009, 714/2009 and 715/2009
[13] http://www.europarl.europa.eu/oeil/FindByProcnum.do?lang=2&procnum=COD/2009/0108

third package finally sets the target, where possible, to equip at least 80% of consumers with smart meters by 2020[14] as a first step towards the implementation of smart grids.

Furthermore, the European Council[15] has set as an EU objective an 80-95% reduction in greenhouse gas emissions by 2050 compared to 1990 levels, in the context of necessary reductions by developed countries as a group. The Europe 2020 strategy therefore includes the establishment of a vision of changes required to move to a low carbon, resource efficient and climate resilient economy by 2050. In this context, there is work on-going within the Commission to outline a vision concerning climate action and possible roadmaps for a transition to a low-carbon energy system by 2050. Infrastructure development and planning of today has to ensure that investments made in the next two decades are compatible with the long term vision.

## 2.2. Current TEN-E framework and European Energy Plan for Recovery

The **TEN-E framework** has been developed and shaped in the 1990's through the successive TEN-E Guidelines and the corresponding financing Regulation[16]. The current objectives of the TEN-E policy are to (1) support the completion of the EU internal energy market while encouraging the rational production, transportation, distribution and use of energy resources, (2) reduce the isolation of less-favoured and island regions, (3) secure and diversify the EU's energy supplies also through co-operation with third countries, (4) contribute to sustainable development and protection of the environment (including *inter alia* a greater use of renewable energy sources and the reduction of environmental risks associated with the transportation of energy). The current TEN-E policy framework includes electricity, gas and olefin transmission networks, but not CO2 transportation, neither oil pipeline infrastructure. The guidelines establish a framework for closer cooperation, for example through better exchange of information and coordination between Member States. The guidelines foresee that, when projects encounter significant delays or problems, a European coordinator may be appointed to the project in order to facilitate coordination and monitor progress. Four coordinators have been appointed in September 2007[17], on the basis of the Priority Interconnection Plan[18].

The 2006 guidelines for Trans-European Energy Networks listed about 550 projects eligible for Community support according to the above-mentioned objectives, ranking them in the following three categories: projects of European interest (42 in total); priority projects and projects of common interest. These projects cover only electricity and gas infrastructure, no oil, olefin or CO2 transportation infrastructure.
The report on the implementation of the TEN-E framework in the period 2007-9[19], published in April 2010, concluded that the policy made a positive contribution to selected projects by giving them political visibility and the TEN-E label facilitates communication to and collaboration with third parties. However, there is a lack of focus within the current guidelines and not enough clarity between the categorisation of projects (common interest, priority project, European interest). The list of targeted projects is rigid: new projects and technologies (e.g. electricity storage, CNG etc.) cannot be included. The guidelines are based on a bottom-up selection of existing projects but do not leave space for a top-down approach to fill identified infrastructure gaps. There is no mechanism to ensure that Member States grant projects of EU importance the same priority as their national projects. The

[14] Annex 1 of Directive 2009/72/EC
[15] European Council conclusions, 30 October 2009
[16] Decision No 1364/2006/EC laying down a series of guidelines for trans-European energy networks and repealing Decision 96/391/EC and Decision No 1229/2003/EC; Regulation (EC) No 680/2007 laying down general rules for the granting of Community financial aid in the field of the trans-European transport and energy networks
[17] http://ec.europa.eu/energy/infrastructure/tent_e/coordinators_en.htm
[18] COM(2006)846
[19] COM(2010)203 and SEC(2010)505

current TEN-E framework is not binding and places no obligations on Member States or project promoters to really invest and construct infrastructure. TEN-E support may be given to competing and – within a given timeframe – mutually exclusive infrastructure projects. While there is a strong link between the EU's external energy policy and infrastructure development, coordination between TEN-E and external aid programmes has been insufficient.

The TEN financing Regulation[20] adopted on 20 June 2007 sets out the conditions for TEN-E funding and, in particular, states that co-financing can be granted for up to 50% of studies' cost and 10% of eligible works' cost, in particular to projects of European interest. The budget for the period 2007-2013 is 155 million euro (about 22 mln € per year). Currently, TEN-E plays a particularly important role for immature or risky projects and feasibility studies. However, no precise methodology was established to assess the "additionality" of EU support, i.e. the specific contribution of TEN-E funds to making projects actually bankable.
The TEN-E Programme's limited financial resources may have been adequate when focused on studies for remaining problematic interconnections, but the paradigm shift to a low carbon energy system and hence the major evolution and investment needed in energy infrastructures in the coming years call for a reassessment of the TEN-E instrument to ensure its future effectiveness. The TEN financing Regulation allows only grants and interest rate rebates, while the market rather needs innovative financial instruments such as guarantees or equity participations for risk mitigation. The current financing Regulation does not allow the funding capital expenditures outside the EU, while large gas import infrastructure and related connection to upstream sources or even electricity interconnections with third countries go well beyond EU borders.

This demonstrates that the current TEN-E policy and financing framework is not effective enough given the above described dramatic changes in the wider policy context.

Set up in the context of the economic and financial crisis, the **European Energy Plan for Recovery**[21] has responded to some of the weaknesses identified above by allocating, for the first time, significant amounts (around 4 bn€) to a rather limited number of eligible projects in the domain of electricity and gas interconnectors, gas reverse flows and storages, off-shore wind and CCS demonstration projects. The objective was to help overcoming possible financial difficulties caused by the economic and financial crisis and thus to contribute to the expenditure for the implementation of the most mature projects, in order to speed up and secure investments and accelerate their construction.

## 2.3. Main problems

The challenges and drivers as well as the obstacles hampering energy infrastructure development and the resulting main consequences of insufficient infrastructure are summarised below:

[20] Regulation (EC) No 680/2007
[21] Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Union financial assistance to projects in the field of energy (OJ L200, 31.7.2009)

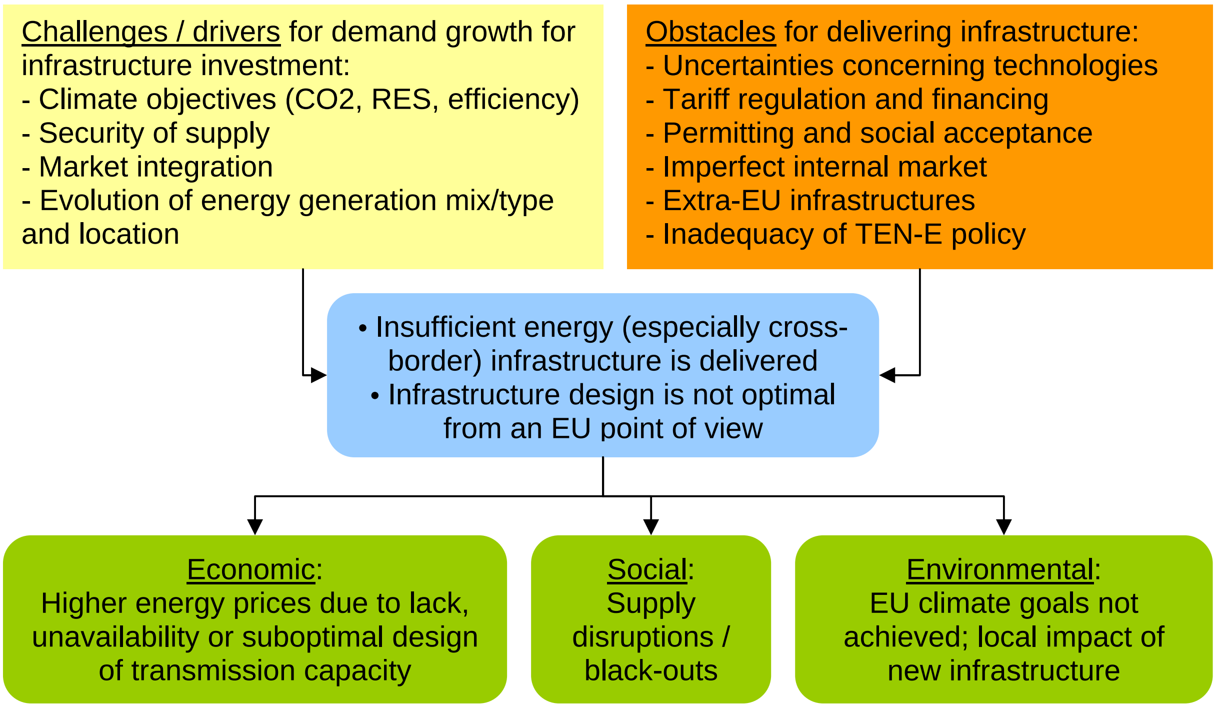


**Figure 1**

As pointed out in the introduction, the new policy context triggers substantial needs for new energy infrastructure investment in the EU, which is estimated at about 200 billion euros up to 2020 (see chapter 0 for details). However, due to the obstacles described in this chapter, not all the necessary investment will materialise under current conditions. The obstacles to adequate development of infrastructure can be described in detail as follows:

1) **Huge uncertainties concerning future technologies** in terms of their availability, possible risks and cost competitiveness, standards for the interoperability and scalability of systems (notably for certain renewable energy technologies, offshore grids and smart grid infrastructure, but also for electricity storage and CCS, currently not included in the TEN-E framework), **energy mix and geographical distribution** of future plants (electricity), **and new sources** (unconventional gas, green gas, LNG/CNG, new import infrastructure and upstream development in third countries) add to the overall uncertainty of future energy market developments and lead to sub-optimal market solutions (from an EU point of view).
   The market players and/or regulators do not anticipate future demand / capacity needs if it is not commercially viable or would result in higher tariffs in the short term. This will result in increased cost over time (in the long term) and higher environmental impact (for example a number of smaller pipelines instead of one large).

2) **Tariff regulation and financing:** Transmission is a regulated business at national level and cost allocation to final beneficiaries is difficult or impossible for large trans-European infrastructure. In order to keep transmission tariffs as low as possible, tariff regulation in most Member States has been based on the principle of cost-efficiency, allowing recovery of costs only for projects based on real market needs or cheapest available solutions. There are in particular three types of projects, whose realisation is typically hindered through this approach:
   a. Projects with higher regional than national benefit:
      The higher the regional or EU benefit of a project, i.e. the more Member States are involved, the more complex it often is (cross-border issues including e.g. different regulatory regimes concerning rates of return or investment amortisation

periods, different permitting procedures etc.) and the more difficult cross-border coordination gets, especially if the costs and benefits of the project are shared asymmetrically between Member States. This complexity increases the project risks and hence the financial needs, which will not be covered by the market and new third package rules alone. It will result in sub-optimal solutions in terms of overall European or regional benefit.

b. Projects using innovative technologies[22] typically involve higher risks, as their industrial-scale applicability and business case are not fully proven yet. Nevertheless, market players do often not ask for and/or regulators do not approve a higher rate of return to make them bankable. Thus, first-of-their-kind projects that use new technologies for generation (e.g. carbon capture and storage) or transmission (e.g. DC VSC offshore grid technology, storage, smart grid applications), and which are necessary for the achievement of the EU energy and climate goals, will not be implemented within the set timeframe[23].
Uncertainty on the appropriate market model and regulatory approach for the above mentioned technologies also lead to suboptimal solutions.

c. Infrastructure with the objective to enhance security of supply – in pursuit of the infrastructure standards included in the new regulation on security of gas supply (N-1 and reverse flow) – is needed all over the EU, but is only rarely if ever justified by market demand and transported volumes as it is used only in case of supply disruptions (low probability / high impact events), but not under normal market conditions. In many Member States, most of them with relatively low per capita GDP levels, there has so far been no regulatory solution on how to recover the costs of these investments, and financing through tariff increases will be difficult to achieve[24].

In addition, there are externalities concerning the financing of infrastructure: TSO's must justify their investment to the national regulator by looking at future revenues only from transmission; they cannot factor in revenues from business opportunities such as price arbitrage between markets or market contestability (lower prices in a given market due to the threat of competition). For the same reason, supply shortage or increased market prices (due to lack of infrastructure) have no or little impact on TSO revenues, while they have a huge economic impact on commodity markets.
Finally, as a result of the financial crisis, and the current rapid evolution of rules in the financial sector, access to capital has become more difficult since 2008. Credit ratings of many TSOs have deteriorated and still continue to do so. There is also a lack of adequate financing instruments, risk capital and loans at sufficiently long maturity. Furthermore, there seems to be a lack of knowledge within the financial sector, notably among potentially interested investors (such as private wealth funds), on how to evaluate energy infrastructure investments.

3) **Permitting and social acceptance:** Long and uncertain permitting procedures were indicated by industry as one of the main reasons for delays in the implementation of infrastructure projects, notably in electricity. This puts a major additional risk on investments in power generation and transmission and has slowed down or even stopped new projects. In several Member States, public opinion is turning progressively against new projects and in particular overhead electricity lines, adding to the obstacles faced by projects due to inappropriate authorisation procedures and administrative practice.

[22] Cf. Impact Assessment of the SET Plan (SEC (2009) 1297)

[23] The European Electricity Grid Initiative (EEGI), launched in the framework of the SET Plan, has identified research and development priorities for both electricity transmission and distribution covering the period up to 2018. The functional areas covered include improved grid planning, renewables integration, both on- and offshore, and smart grid applications, with a budget estimated at 2 bn€, out of which about 560 m€ for transmission activities alone. However, the projects focus on studies only and do not cover industrial-scale works.

[24] Cf. "Commission Declaration on long term security of supply measures" related to Regulation XXX/2010 concerning measure to safeguard security of gas supply and repealing Directive 2004/67/EC

Therefore, the time between start of planning and final commissioning of a power line is frequently more than 10 years, be it a domestic or a cross-border project. With significant permitting obstacles and public opposition, projects can take up to 20 years to be completed[25]. Cross-border projects often face additional opposition, as they are frequently perceived as mere "transit lines" without local benefits. Limited public understanding for the benefits of a given project or technology might also limit in particular the roll-out of smart-grid applications.

4) **Imperfect internal market**: there is weak competition in some Member States where national markets are still dominated by incumbents (such as Belgium, France, Greece, Latvia, Luxembourg or Slovakia in electricity and Finland, Greece, Latvia, Lithuania, Luxembourg, Poland, Slovakia and Slovenia in gas)[26]. Lack of infrastructure constitutes a high entry barrier for new entrants, especially in markets, which are dominated by historic operators and will most likely remain so over the coming years, despite third package provisions on unbundling. Lack of market development does not allow TSOs to have sufficient firm capacity contracts to invest in an interconnector between two markets; at the same time, the market is unlikely to be able to develop as long as there is no interconnector.

5) **Infrastructures external to the EU.** For energy infrastructures outside the EU that will be required to meet the EU's growing need for imported gas and oil and to improve security of supply through diversified supply sources and routes, or to import "green electricity", there are additional political risks. Beside the need to engage politically with third countries to identify and ensure a mutual benefit from new energy infrastructures, risks may range from an unattractive or non-transparent investment framework in the third countries through to the risk of changes in the fiscal/tax or legal environment once the investment has been made.

6) **Inadequacy of the current TEN-E policy** as described in chapter 2.2.

It clearly derives from the above that the new energy policy context has created huge challenges for EU infrastructure development at a continental scale. Current policies aiming at connecting national grids will not be sufficient, as there is a need to build a fully interconnected European network for electricity and gas, including through new electricity super-grids.
To meet the EU's energy and climate goals for 2020 and beyond up to 2050, massive investments are required in energy networks and particularly in Europe's electricity grids over the next two decades up to 2030 as a necessary condition for change to happen in energy generation, supply and demand. Given the problems encountered, these investments will not happen quickly enough without strong action both at national and Community level.

This Impact Assessment aims at supporting the forthcoming Communication with the objective to establish a broad policy direction for future infrastructure development. This initiative hence broadly addresses the above identified problems, in particular the uncertainties, the issues surrounding permitting, external policy aspects of infrastructure and the inadequacy of the current TEN-E, including inter alia the lack of focus and the rigidity of the identified project list.

The proposals included in the Communication and the remaining problems will be addressed and followed up next year through the legislative proposal for an EU Energy Security and

[25] ENTSO-E 10-year network development plan, June 2010
[26] Benchmarking Report (COM (2010) 84) and technical annexes (SEC (2010) 251)

Infrastructure Instrument, for which a specific impact assessment will be prepared with particular focus on financing, tariff regulation and an in-depth analysis on permitting.

## 2.4. Baseline scenario

This chapter presents the likely evolution of networks and bottlenecks in terms of infrastructure development under the current policy framework.

**Box 1: Methodology used for infrastructure investment needs assessment**

The analytical tools used are the following:

a) for determining energy balances in 2020 and 2030, the PRIMES model (using the results of GEM-E3, PROMETHEUS and GAINS modelling as inputs);
b) for evaluating resulting infrastructure needs in the electricity and gas sector, a specialized grid modelling framework developed by KEMA and Imperial College London;
c) for assessing infrastructure needs for $CO_2$ transport, two specialized analysis and modelling tools developed by ARUP and JRC. Experience from on-going investments was also analysed.

**a) PRIMES modelling of energy balances**

The PRIMES model is a modelling system that simulates a market equilibrium solution for energy supply and demand. The model is organized in sub-models (modules), each one representing the behaviour of a specific (or representative) agent, a demander and/or a supplier of energy. Several EU baselines and scenarios have been established at different points in time using a framework contract with National Technical University of Athens (author and owner of the PRIMES model). Energy modelling is a tool for informed policy making. For instance, the PRIMES 2007 baseline was used to analyse impacts of the energy and climate package in 2008. This analysis relies on the 2009 update of PRIMES. Two recent scenarios have been developed:

- the **Baseline 2009** that takes into account the policies implemented in the Member States up to April 2009;
- the **Reference scenario**, which includes policies up to the end of 2009 and assumes the achievement of the legally binding targets on renewables and greenhouse gas reduction.

The latest update is based on an average GDP growth of 1.7% per year for the period 2005-2030 as opposed to 2.2% in the 2007 baseline. The energy projections are based on a relatively high oil price environment compared with previous projections and similar to reference projections from other sources, with oil prices of 59 $/barrel in 2005 rising to 106 $/barrel in 2030 (in year 2008-dollars). Significant changes in these assumptions alter the energy outlook for the next 20 years. Primary energy consumption stabilizes at today's level as compared to rising consumption in 2007 baseline. Less electricity is projected but with more RES in the system (impacts on electricity grid) as well as lower demand for gas (lower gas imports). More information can be downloaded from the Europa website:
http://ec.europa.eu/energy/observatory/trends_2030/index_en.htm

**b) Modelling of electricity and gas infrastructure requirements**

Investment needs were assessed for electricity and gas infrastructure, taking into account the available information in the 10-year network development plans prepared by the two European Networks of Transmission System Operators (ENTSO, introduced by the 3rd package),taking into account also the interdependencies between the two sectors. It should be noted that a forecasting exercise with a time horizon of up to two decades can only give indicative results, given the uncertainties surrounding future supply, demand and price developments.

*Electricity*

The requirements for investment in **electricity infrastructure** were estimated using a modelling framework developed by KEMA and Imperial College London (ICL), which divides the investment requirements into two parts:
- an investment estimate for the interconnection requirements between Member States to evaluate cost-optimal regional interconnection and generation capacity requirements for system security purposes, and the annual operating costs of the system;
- an investment estimation for the cost of integration of offshore wind capacity based on a separate estimation tool.

The investment model divides the EU27 countries plus Norway and Switzerland into 29 regions. The model trades off the various investment elements and optimises based upon input cost assumptions. The scope of the transmission system analysis is focused on incremental capacity requirements between the regions for each future scenario relative to the current 2010 baseline, but respecting the anticipated 2020 transmission capacities contained within the ENTSO-E TYNDP, i.e. all investments in the ENTSO-E TYNDP are assumed to happen in all scenarios.

Three scenarios were modelled, two based on PRIMES 2010 Reference scenario in 2020 and 2030 and a further High Renewable Energy Source scenario (High RES) in 2030. The modelling results provide snapshots of electricity transmission network investment requirements, additional generation investments and associated operational costs aligned with the respective time horizon.

For each scenario, the European electricity system is modelled as a 29-node system with 54 defined interconnection possibilities between these nodes. The system consumption and peak demand characteristics are common in the two 2030 scenarios and greater than the overall electrical energy requirement assumed in the 2020 scenario. The consumption data for all scenarios is aligned with PRIMES consumption forecasts including the net electricity import/export position.

The modelling approach relies on a cost estimation methodology. It seeks to provide an indication of the capital costs associated with expanding the interconnection capacity between Member States to maintain a power system with security characteristics similar to those experienced today. The modelling framework does not provide specific costs for any particular circuits to form the indicated transmission capacity. Nor does it assess the investment requirements for connections due to growing demand or investment in the distribution network.

Both technical and cost assumptions were developed in the framework of a previous extensive analysis of industry standards and learning rates and vetted by key industry stakeholders. Assumptions and results were also discussed in detail with ENTSO-E experts in charge of the TYNDP preparation, which have confirmed the validity of the general modelling approach and the indicative nature of the investment need results.

It must be underlined that this modelling exercise covers only transmission needs for interconnection and offshore connection. Changes in the generation capacity mix (e.g. due to structural variations in fossil fuel prices), in energy demand (e.g. due to slower or faster than expected economic growth) or in the costs for certain specific transmission technologies could have a significant impact on the outputs of the model. While it is assumed that assumption errors for the individual transmission investments will offset each other to some extent, it has been estimated that the aggregate error on investment costs could be in the range of +/–15%.

The evaluation of investment needs in Smart Grids has been based on the most recent available literature, in particular the findings of the High-Level Advisory Group on ICT for Smart Electricity Distribution Networks. The figures used are only very first indications and could vary significantly, depending on future technology cost evolutions.

*Gas*

The requirements for investment in gas infrastructure were based on gas demand projections from the PRIMES baseline 2009 and Reference scenario 2010 for 2020. These projections were matched for consistency against data coming from stakeholders (preliminary ENTSOG estimates, Eurogas) and analysing the most recent studies[27] and available documentation regarding gas infrastructure

[27] "Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios", study by EWI Institute of Energy Economics at the University of Cologne. May

development projects, including investment in LNG terminals, natural gas storage and reverse flow projects. The estimation of gas infrastructure investment need is to some extent dependent on the assumptions concerning future gas demand, which again depend to a limited extent on assumptions concerning GDP growth, but to a far higher extent on a series of other factors such as gas prices (partly based on mainly oil-indexed long-term contracts, partly decoupled from oil price and based on global supply and demand balance), the role of gas in electricity generation and in particular as back-up for variable electricity energy from renewable sources, the level of market integration and the infrastructure and supply standards for security of gas supply and finally the cost of infrastructure (which can vary highly based on the routing for pipelines, cost of steel, the geological conditions for storage etc.). This would add an overall +-25-30% range to the identified figures (about +-20% for storage and interconnectors and up to 50% for import infrastructure).

### c) Modelling of CO2 infrastructure requirements

The requirements for investment in $CO_2$ transport infrastructure were determined, based on the amount of $CO_2$ indicated as captured under both the PRIMES baseline 2009 and Reference scenario 2010. Modelling was prepared by JRC, using a dedicated analytical tool (InfraCCS) and the following four methodological steps:
- Identification and clustering of $CO_2$ sources and sinks;
- Assumptions about the evolution of captured $CO_2$ emissions and storage capacities;
- Routing of potential pipelines between nodes;
- Selection of the optimal network and evolution over time.

Given the fact that the EEPR CCS projects are already under development, the model runs under both PRIMES scenarios resulted in the same required network length, with the Reference scenario delivering slightly lower investment needs due to the fact the pipelines to be deployed would not have to be oversized. Uncertainties remain concerning the evolution of $CO_2$ demand beyond 2020, which will have to be analysed in more detail to confirm the need for pipeline oversizing.

ARUP prepared a separate analysis to determine the optimal $CO_2$ transport network in Europe and its evolution over time, based on predefined volumes of $CO_2$, identification of suitable storage sites and a cost-minimisation approach. The study analysed snapshots for 2030 and 2050. The results can therefore not be directly compared with the results of JRC analysis. However important similarities have been recorded in the shape of the future network proposed by both studies, confirming that a regional approach to developing the future network will be essential.. Assumptions of the study were discussed in detail with the EC Fossil Fuels Forum (Berlin Forum) stakeholders. Zero Emission Technology Platform (ZEP TP) was also consulted. Moreover, ZEP's Chairman in his letter of 30 June 2010 addressed to the Energy Commissioner stressed that the policy objective of ensuring the development of networks to permit the achievement of the EU's energy and climate objectives should explicitly be extended to include the development of new $CO_2$ pipeline infrastructure. EURELECTRIC was also consulted. It xtended its support to a coordinated approach to the development of a $CO_2$ pipeline network across Europe and recommends that CO2 infrastructure should be included in the upcoming infrastructure instrument. Furthermore, EURELECTRIC supported assumptions of ARUP's study, in particular as regards developing scenarios outlining different transportation roadmaps. A number of other stakeholders supported Commission's approach.

It is important to point out that deployment of CCS could have an important contribution to meeting the GHG reduction targets as described in the Energy and Climate package. The impact assessment prepared for the Directive on the geological storage of carbon dioxide proves that without enabling policy for CCS at EU level (that is, achievement of climate objectives without CCS), the costs of meeting a reduction in the region of 30% GHG in 2030 could be up to 40% higher than with CCS. Thus not enabling CCS would have substantial negative impacts on Europe's capacity to meet the 2 degrees Celsius target and on competitiveness, and also for employment, and would have a slight negative impact on security of supply.

2010 and "The revision of the trans-European energy network policy (TEN-E)", impact assessment study by COWI, Cambridge Econometrics and KEMA

### 2.4.1. *Energy trends and infrastructure needs*

The PRIMES reference scenario has been used to estimate future demand for energy up to 2030, the impact assessment itself being limited to 2020. The results have been compared to the PRIMES baseline scenario[28] and other scenario results. It is assumed that the two binding targets (20% renewables share and -20% greenhouse gas emissions) are achieved in the Reference scenario, implying that all other necessary implementing provisions (such as the energy infrastructure policy) will be completed. In the baseline scenario, based only on continuation of already implemented policies, these targets are not achieved. While primary energy consumption is projected to remain largely stable at 1,800 Mtoe and final energy demand at 1,200 Mtoe between 2010 and 2030 in both the PRIMES baseline and the PRIMES reference case scenario, the use of electricity and in particular renewable energies tends to increase significantly over the period, while the use of coal, but also oil and gas decline under both scenarios, however at a substantially different pace. In the following, we give a more detailed overview of the likely evolutions by sector.

The **electricity** sector is expected to face increasing demand, partly because of a major fuel shift in the overall energy mix as a result of the greenhouse gas reduction goals, but also because of its convenient use and the multiplication of applications relying on it as an energy vector (heat pumps, electric vehicles, information and communication technology devices etc.). EU-27 gross electricity generation is projected to grow from about 3,362 TWh in 2007 to 4,073 TWh in 2030. At the same time, the electricity generation mix is changing, with less fossil fuels and more renewable and variable energy sources. According to the Reference scenario, their share in gross electricity generation is expected to be around 33% by 2020 and 36% in 2030, out of which variable sources (wind and solar) could represent around 16% in 2020 and almost 20% in 2030. Significant new renewable capacities will be concentrated in locations further away from the major centres of consumption (offshore wind parks, ground-mounted solar parks), while decentralised generation will also gain field. This change in the nature of both generation and consumption patterns will require both electricity transmission and distribution grids to play an ever more important role in flexibly balancing supply and demand over increasing distances, while maintaining the same levels of security of supply. At the same time, the correct functioning of the internal electricity market will require additional cross-border interconnections and reinforcements of domestic grids. Annex 1 shows the major additional cross-border transmission capacity needs until 2015 and beyond, as estimated by ENTSO-E.

All these factors trigger large-scale investment needs at a level not seen over the past decades, both within Member States and cross-border, including in areas almost not covered today by electricity grids such as the Northern and the Baltic Seas. ENTSO-E's first TYNDP compiles a list of about 500 projects selected by national TSO's and identified as being of European significance because of their contribution to market integration, integration of renewables or security or supply[29]. This list amounts to a total of about 42,100 km (35,300 km new connections, 6,900 km upgraded connections). For new lines alone, this corresponds to doubling the annual extension of the currently operational European transmission grid, with a growth rate of about 1.5% between 2010 and 2020, compared to an annual average of 0.8% for the EU-15 during the period 1989-2003[30]. This corresponds to an

[28] EU Energy Trends to 2030: Update 2009 (Baseline 2009 and Reference scenario 2009). A detailed description of these scenarios and their assumptions is available at http://ec.europa.eu/energy/studies/index_en.htm.
[29] It must be stressed that this list does not include local, regional or national projects, which are not considered to be of European significance. As many transmission grids were built in the 1950's and 1960's and near the end of their lifetime, important additional investment needs will arise from the renewal or refurbishment of existing local, regional and national lines.
[30] "Lessons from Liberalised Electricity Markets", OECD/IEA 2005, p.145

annual investment of about 3.3-4.7 bn € per year for projects of European significance. According to ENTSO-E's own calculations, these projects correspond to an overall investment need of 50-70 bn€[31] for the period 2010-2025[32]. According to KEMA calculations, these projects would need to be operational in 2020 to reach the 20-20-20 targets[33].

As underlined by ENTSO-E, the first TYNDP does not take full account of needed infrastructure investment triggered by important new offshore wind generation capacities in the Northern Seas[34]. According to the national renewable energy action plans submitted by 19 Member States in application of directive 2009/28/EC[35], 2020 installed capacity is estimated at over 40GW, while 56 GW are needed according to the PRIMES reference scenario. According to calculations done by KEMA, this adds investment needs of about 32 bn€ for offshore connection infrastructure by 2020. In the medium term up to 2030, more offshore wind and development of solar energy generation capacities in Southern Europe and beyond will trigger further transmission grid development needs. According to KEMA estimates, overall offshore connection and cross-border interconnection needs could amount to an additional 18 bn€ in the period 2021-2030 under a PRIMES reference scenario with about 36% of renewables in gross electricity generation in 2030, or as much as 100 bn€ under a more ambitious High-RES scenario developed by KEMA with about 50% of renewables by 2030[36].

Moreover, reaching the EU's energy efficiency and renewable targets might not be possible without more intelligent networks, based in particular on more demand side management and smart grid technologies. Digitised electricity grids enable two-way communication between suppliers and consumers and feature an intelligent monitoring system to track electricity flows in all directions. This will contribute to reducing network losses, increasing the reliability of the grid and allowing large amounts of variable renewable power to be connected to the grid. Moreover, smart grids will enable consumers to control appliances at their homes to save energy, facilitate domestic generation, reduce cost and increase transparency. The investment needs in smart grid technology to make networks "intelligent" as a whole and get the expected benefits out of 200 million smart meters has been estimated at 40 billion € by 2020[37]. By 2030, total additional investment in smart grids deployment in the EU could reach 176 bn€, out of which 50 bn€ for smart metering, according to the final High-

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[31] Note that transmission investment costs are highly sensitive to technology choices. The investment cost for undergrounding cables, e.g. to reduce their environmental impact, is typically 3 to 10 times higher than the investment cost for an overhead line or even more if specific structures are needed (Source: ENTSO-E and Europacable).

[32] By comparison, the average investment on *all* transmission infrastructure in the EU from 1996 to 2004 has been around 3.1 bn € per year. The largest part was devoted to substations (40%), internal lines (33%) and other assets (23%), such as telecommunication, protection and control, and special equipment, while only 4% of the total has been devoted to cross-border lines, mostly for HVDC interconnections through submarine cables (source: TEN-Energy-Invest study). While the resulting increase in annual investment would be significant (up to over 50%), it is not expected to overstretch the absorption capacity of the industry. On the one hand, TSOs are preparing themselves for this "wave" of investments over the coming years. On the other hand, the supply chain is fully ready to answer such increased demand, as it supplies already today significant volumes to strongly growing electricity transmission markets in e.g. China or India.

[33] "The revision of the trans-European energy network policy (TEN-E)", chapter 3

[34] It is expected that the next edition of the TYNDP planned for 2012 will take a more top-down approach, with a view beyond 2020, and address these shortcomings.

[35] Plans received and analysed as of 1st of September 2010

[36] It should be noted that these scenarios also have significant impacts on both back-up capacity needs and operating costs. KEMA has calculated that additional generation investment of about 42 bn € would be needed by 2030 under PRIMES reference to ensure current levels of system reliability. Under High-RES, this investment would reach 93 bn €. This would however be compensated by lower total annual generation operating costs under High-RES 2030 (130 bn €) compared to PRIMES reference 2030 (160 bn €). Note that this calculation does not take into account costs for developing the corresponding renewables generation capacity, which should be far higher than the related grid or back-up capacity investment.

[37] DG ENER calculations based on DG INFSO report "Impacts of Information and Communication Technologies on Energy Efficiency". The 80% target of Directive 2009/72/EC corresponds to equipping 200 million European households with smart meters. The cost for this equipment amounts to another 40 billion €.

Level Advisory Group on ICT for Smart Electricity Distribution Networks. The evolution towards smart grids faces multiple challenges, given the technology changes involved, the absence of harmonised standards and markets rules. Because of the uncertainties and high costs, no single one party is able to afford smart grid investment at transmission level on its own. Moreover, even if cost-benefit analyses in Member States show overall smart metering benefits, absence of appropriate regulation leads to unequal allocation of cost and benefits to the different parties in the value chain. In the medium term, new high-voltage long distance grid technologies and new electricity storage technologies will also be necessary. Uncertainties remain today as regards the potentials and risks of these different technologies.

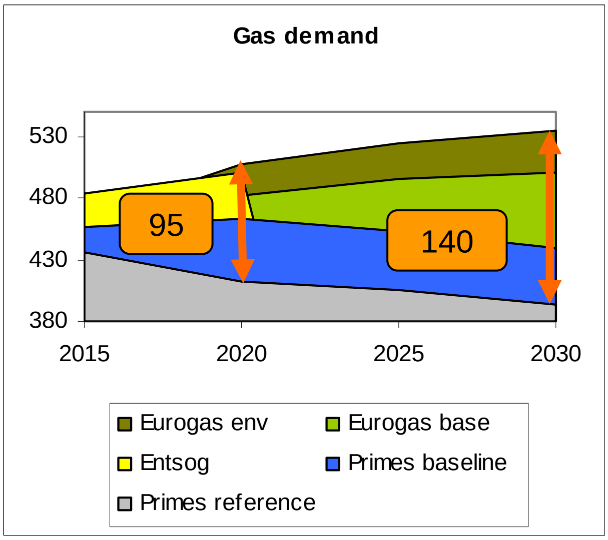


**Figure 2, in Mtoe**

The overall investment need for electricity networks (including offshore and smart grids) is estimated at 142 bn€ until 2020[38]. However, the attainment of this target is currently highly unlikely because of the delays observed for the planning and authorisation of overhead electricity lines, because of uncertainties concerning technologies needed, planning coordination and cost-benefit allocation for offshore grids deployment, and because of uncertainties related to technologies, common standards and appropriate market models and incentive regulation for smart grids. It is estimated that only about 30% of the total investment needed would be delivered under a business-as-usual scenario.

**Gas** demand is highly dependent on energy policy choices. High uncertainty is surrounding the future of gas demand, as is demonstrated by the difference between various demand scenarios presented in Figure 2. While binding RES targets may crowd out gas fired generation (37% of gas demand in 2006) as base-load, they will also increase its role as back-up. At the same time, the development of new technologies, such as CCS, which is highly dependent on the price of emission allowances in the EU ETS, may increase the importance of gas in power generation. On the other hand, efficiency gains in buildings may reduce gas demand.

The main challenge that **gas** infrastructure faces is the high and growing dependence on gas imports (to reach about 73-79% by 2020 and 81-89% of consumption by 2030) mainly due to the depletion of indigenous resources. Based on the different scenarios, the additional import need ranges from 44 Mtoe to 148 Mtoe by 2020 and from 61 to 221 Mtoe by 2030[39] (compared to 2005). Import dependency calls for sufficient and diversified import infrastructure from various sources. This development should be closely linked with the EU's strategy towards third countries.

[38] The level of in-country, cross-border and offshore grid infrastructure also determines additional back-up capacity requirements in the different Member States. According to KEMA calculations based on PRIMES reference, additional generation investment based on the cheapest available flexible generation technology would amount to 18 bn € by 2020.

[39] For the whole section on gas, the lower figures refer to the PRIMES 2010 reference scenario, while the higher figures are derived from the Eurogas Environmental Scenario published in May 2010, based on a bottom-up collection of the members' estimates.

In addition, the increase of electricity production from variable renewable energy sources requires additional flexible back-up generation. A large part of it is expected to be provided by gas-fired power plants. Given current interconnection and forecast error levels, Eurelectric estimates that 200 GW of installed wind capacity correspond to about 20-30 GW of back-up capacity needs. This increases the need for flexibility, such as LNG/CNG, more flexible use of pipelines and in particular **gas storage** (both working volume as well as injection and withdrawal capacity), moving away from the traditional "injection in the summer, withdrawal in the winter" patterns. According to some estimates, about 30-39 million cubic meters of annual working volume are needed to balance 1 GW of installed wind capacity in the absence of other measures (such as demand side management).

Thus the investment need for gas infrastructure in the coming decade has been estimated (according to internal calculations based on conservative gas consumption assumptions) to reach 71 bn€[40], including EU internal interconnectors (including reverse flows), new import infrastructure (pipelines and LNG) and storage requirements[41]. However, given the problems faced by these projects as outlined above, notably in terms of authorisation delays, insufficient market development, lack of cross-border coordination and economic viability, it is estimated that only about 80% of the corresponding projects would be delivered under a business-as-usual scenario. More details to the figures are given in Box 2 under chapter 5.1.

80% of imported crude **oil** is currently delivered to the EU by tankers. An important feature of the internal EU oil transport network is that the Western part is connected via pipeline to major European ports while most of the refineries in Central and Eastern Europea (EU12) are supplied through the Druzhba oil pipeline system from Russia (about 60 million tons/year). There are limited connections between the Western European pipeline network and the eastern infrastructures. This is a consequence of the fact that the Eastern European pipeline network (an extension of the final part of the Druzhba pipeline) was conceived and built during the Cold War period and had, at that time, no pipeline link with the western network. Moreover, in these countries, unlike in the EU15, the oil demand is expected to grow by 7.8% between 2010 and 2020 (see **Error! Reference source not found.**). In case of supply disruptions in the Druzhba system, the limited alternative supply options would lead to a big increase in tanker traffic in the environmentally sensitive Baltic area[42], in the Black Sea and in the extremely busy Turkish Straits[43], creating big concerns about the potential danger of accidents and oil spills. This puts pressure to develop oil pipeline infrastructure to ensure security of supply in this region.

**CCS** is a novel technology, which comprises the capturing of CO2 at emission points, its transportation and underground storage in suitable geological formations. To date, the implementation of CCS has been limited to pilot plants and the first large-scale demonstration projects are under development to be deployed around 2015 supported by Community funds, the New Entrants' Reserve of the EU Emissions Trading Scheme (the so called "NER300 initiative"[44]), state aid and contributions from developers. The Commission's

[40] The investment need may range from about 50 to 89 bn € based on various factors described in Box 1.

[41] ENTSOG is currently elaborating on the investment need for the coming ten years to be included in their next TYNDP to be published in December 2010. To date, their non exhaustive analysis (work in progress) has estimated about 41 bn € of identified investment need. The above mentioned figures have been checked also against available (partial) studies.

[42] The Baltic Sea today is one of the busiest seas in the world, accounting for more than 15% of the world's cargo transportation. Each month 3,500-5,000 ships cross the waters of the Baltic Sea. Approximately 17-25% of these ships are tankers transporting approximately 170 million tonnes of oil a year.

[43] The Turkish Straits comprise the Bosporus and Dardanelles. Less than a kilometre wide at their narrowest point, the Turkish Straits are one of the world's most difficult waterways to navigate, due to their sinuous geography. With 50,000 vessels, including 5,500 oil tankers, passing through the straits annually, they are one of the world's busiest and most dangerous chokepoints.

[44] Cf. article 10(a) 8 of the revised Emissions Trading Directive 2009/29/EC

ambition, supported also by the Council, is to have up to 12 such plants. The demonstration projects will include integrated value chains consisting of CO2 capture installations, transport and storage infrastructure. The use of pipelines is widely considered to be the most reliable for long-term bulk movement of CO2. Whilst storage capacity in Europe is plentiful, it is not evenly distributed geographically and in some cases distant from significant emission sources. Moreover, some EU Member States, considering their significant levels of CO2 emissions, have limited potential storage within their state boundaries which calls for cross-border transport infrastructure. The development and marketability of CCS technologies – and hence the need for a CO2 transportation network - are highly dependent on the CO2 prices. This is shown in the PRIMES reference scenario (lower CO2 prices due to lower demand for emission permits due to higher share of RES and more energy efficiency in the system) where the share of CCS use in power generation is only 1.4 % in 2030 corresponding to 37.6 Mt of captured CO2. The PRIMES baseline with higher carbon prices allows for more CCS development reaching 8.7% of power generation in 2030[45].

Without intervention, CO2 pipelines installed during 2014-2020 will be relatively short in length, associated with specific projects and therefore tailored to their needs. They will also rather remain geographically remote (i.e. unconnected) from one another. For the period beyond 2020, technology experts expect a commercial rollout of CCS in lead countries followed by a global rollout of CCS after 2025. Beyond 2030, the need for CO2 transport infrastructure could be even more important due to the expected share of CCS in the energy supply mix. This implies a need for early infrastructure development and advanced capacity investment, despite current low price of emission allowances due to the economic crisis. As the results of recent private sector analysis show, it is still more economical to oversize the pipelines initially and wait around 10 years until the spare capacity is fully utilised than to build pipelines fit for one emission point and one CO2 sink[46].

The CO2 infrastructure investment need has been estimated by the JRC at about 2.5 bn€ until 2020. Under a business-as-usual scenario, i.e. without creating the necessary conditions for the early deployment of a European CO2 infrastructure network adapted to future needs, it is estimated that no significant investment will take place.

Moreover, the increased interconnection of energy networks and the use of advanced information technologies represent additional challenges in the event of external events, such as those resulting from natural hazards and human-made malicious threats. The aspects of physical protection of infrastructures, their interoperability under disrupted conditions, and coordinated planning of contingencies will need to be addressed with a European dimension in every future development of energy infrastructures as they are key factors in the overall resilience of the energy supply system.

As a result, the overall investment need amounts to 215.5 bn€ (142 bn€ electricity, including interconnections, offshore connections and smart grids; 71 bn€ gas, out of which 14 bn€ of investment outside the EU; 2.5 bn€ CCS). Taking into account assumptions on business-as-usual market and regulatory conditions determining the commercial viability of projects (see chapter 2.4.2) and delays for project implementation in each sector (electricity, gas and CO2) (see chapter 5.1 and Annex 3 for more details), one can estimate the business-as-usual investment: it would reach in electricity and gas 102 bn€ over the period 2010-2020 (45 bn€ electricity, 57 bn€ gas). No significant investment would take place for the CO2 transport infrastructure as identified in the JRC and ARUP studies..

[45] It must be noted that projections up to 2050 can feature significant changes to these prices, depending on the scenario chosen.
[46] Pre-FEED (front end engineering and feasibility) studies on industrial-scale carbon capture and storage (CCS) demonstration projects in the United Kingdom (2009)

### 2.4.2. *Infrastructure delivery under current market, regulatory and financing conditions*

Electricity and gas infrastructure in Europe are regulated sectors, whose business model is based on regulated tariffs collected from the users, which allow recovering the investments made ("user pays principle"). The regulatory framework for infrastructure (including planning and investment) has evolved through the 3rd internal market package for electricity and gas that was adopted mid 2009, to be implemented by mid 2011. It enhances the separation ("unbundling") between transmission and supply activities. On the one hand, this may translate into more difficulties for TSOs to forecast future demand and no more possibilities of cross-subsidies. Thus regulated tariffs and congestion rents are the only way to recover costs. On the other hand, effective unbundling will give them more independence and increase their incentives to better plan infrastructure investment. The new transparency guidelines will lead to better information within the market, thus to possibly more available capacity for shippers in the case of gas, more optimal use of infrastructure and better signals on congestions where TSOs should invest in additional infrastructure. Generally, a more efficient market should provide better price signals: price differentials will indicate where additional or new interconnection capacities are needed within the European network.

The third package provides for new rules in terms of infrastructure development across borders, which will facilitate the implementation of grid investments in electricity and gas:

- The third package establishes new rules for national regulatory authorities to cooperate on cross-border issues, including operational arrangements, networks codes and congestion management[47]. For electricity only, provisions are made as regards an inter-transmission system operator compensation mechanism for costs incurred as a result of hosting cross-border flows, which should clarify the sharing of costs and benefits for a given cross-border infrastructure[48]. ACER will intervene in particular to establish and monitor implementation of network codes, to coordinate regulatory differences affecting cross-border infrastructure and to monitor the implementation of interconnection projects[49]. Notably the new rules on inter-TSO compensation, which are in the final stage of the comitology procedure, are expected to facilitate the implementation of needed grid investments.

- The new ENTSOs for electricity and gas will facilitate co-operation and co-ordination between TSOs, notably for investment planning. The first European TYNDPs are based on a bottom-up approach and were successful in consolidating existing projects in one single document, thus giving more transparency to network planning. However, they do not provide a top-down vision suited to identify all future infrastructure gaps as a consequence of the new energy and climate policy challenges. More top-down oriented second versions of the European TYNDPs will be published in December 2010 for gas and in 2012 for electricity, giving the start for bi-annual revisions. These plans are ultimately expected to deliver a longer-term vision and setting strategic priorities for future development.

- While the third package gives the necessary powers to national regulators to ensure implementation of investments foreseen in the binding national plans[50], no provision is made to ensure implementation of the European TYNDPs, which are non-binding plans[51]. However, the third package does require that national plans are consistent with the European TYNDP and gives the Agency a monitoring role in this respect. Enforcing

[47] Cf. article 38 of Directive 2009/72/EC and article 42 of Directive 2009/73/EC
[48] Cf. article 13 of Regulation (EC) No 714/2009
[49] Cf. articles 6 and 8 of Regulation (EC) No 713/2009
[50] Cf. articles 22 of Directive 2009/72/EC and Directive 2009/73/EC
[51] Cf. articles 8 of Regulation (EC) No 714/2009 and Regulation (EC) No 715/2009

realisation according to the planning and timing foreseen will be impossible for certain projects listed as being of European interest.

The third package also asks national regulators to provide appropriate tariff incentives, both short and long term, for network operators to increase efficiencies, foster market integration and security of supply and support the related research activities[52]. Although regulators furthermore will have an obligation to take into account the impact of their decisions on the internal EU internal market as a whole, still, tariff setting remains national competence and hence not always conducive to advance European priorities.
Furthermore, this regulatory approach is not designed to address the major technological changes, notably in the electricity sector, concerning offshore or Smart Grids.

As demonstrated above, the measures adopted and, for many, still to be implemented will not be sufficient to ensure full delivery, given the lack of regulatory solutions to allocate costs and cross-border benefits and especially the obstacles identified in chapter 2.3. They will resolve some coordination issues for simple cross-border projects. However, they may not provide sufficient incentives for investments in public goods – e.g. gas reverse flow or storage for security of supply – or projects with information asymmetry – e.g. new technologies or innovative solutions (interconnected offshore grids, smart grid applications) or cross-border projects with complex cost and benefit allocations involving several countries, notably in gas, where no inter-TSO compensation or any other mechanism to allocate costs for domestic investment to final beneficiaries outside the domestic territory has been established. Moreover, while the energy and climate policy goals adopted at EU level and the corresponding support schemes for renewable energies do speed up their development, they have also a distorting effect, notably on the internal electricity market. Finally, they are currently not matched by corresponding measures for infrastructure development to ensure adequate grid integration.

Finally, both the internal markets for electricity and gas are still incomplete, partly due to missing infrastructure[53]. Eastern Europe has inherited East-West gas infrastructures with little or no interconnections between neighbours. As the gas crisis in January 2009 showed, lack of infrastructure and insufficient transmission capacity were the main barriers to the handling of the crisis[54]. The new regulation on security of gas supply has just introduced a compulsory "N-1" rule for infrastructure, meaning that all Member States should be able to compensate the disruption of the single largest infrastructure by the remaining other infrastructures to ensure that total gas demand is met. An obligation to implement reverse flows was also set. In order to meet these standards, additional infrastructure needs to be constructed. However, such projects will not always be bankable under a business-as-usual scenario.

In addition to traditional private financing on the basis of regulated tariffs, EU-funded support has been granted to current TEN-E projects through a number of instruments, such as the TEN-E budget, EEPR, IPA, ENPI (such as NIF or INOGATE) and loans from EIB and EBRD (see Annex 2 for more details). Under current rules – valid until 2013 –, EU TEN funding will continue to give small grants to finance feasibility studies or riskier projects, which may have an important EU-wide benefit. Interest rate rebates figure in the Regulation, but have never been used as they may have a market distorting effect. Projects that are not commercially viable but that may be important for other reasons (security of supply, market integration,

[52] Cf. article 37 of Directive 2009/72/EC and article 41 of Directive 2009/73/EC
[53] In electricity, interconnections have historically been good between Eastern European Member States, which used to be connected synchronously among each other and with the Russian power system. Following disconnection from the Russian system and connection to the synchronous grid of continental Europe (i.e. the grid of the Union for the Co-ordination of Transmission of Electricity / UCTE) in 1995, interconnections between East and West have developed (e.g. between the Czech Republic or Poland and Germany), but certain bottlenecks remain as of today.
[54] SEC(2009)979

new technology or innovative solution), would not be constructed. In addition, the current policy does not address permitting issues, market or regulatory failures, the mismatch between national and European priorities and the need for strong political support. This would lead to insufficient infrastructure development. Finally, oil and CCS infrastructure as well electricity storage and smart grid technologies would remain excluded from the policy. No new electricity/gas projects would be added to the current list, non feasible or outdated ones could not be removed.

Concerning CCS, integrated backbone pipeline networks would probably be the most efficient long-term option, but the incremental cost of building optimized networks ahead of point-to-point pipelines may not satisfy project-specific commercial evaluation criteria. Concerning oil, the current supply situation, in particular with regard to Central and Eastern Europe, is satisfactory. If the uninterrupted and smooth flows from Russia through transit countries could not be ensured in the future, alternative supply routes would have to be explored, either through existing infrastructure (Odessa-Brody pipeline in Ukraine or Adria pipeline in Croatia) or through new West-East interconnections. However, the corresponding investments, which would then become necessary, are limited[55]. They are not regulated by EU legislation concerning e.g. rates of return or third-party access to infrastructure.

## 2.5. Main geographical bottlenecks

In the business as usual scenario, the main bottlenecks would occur in the below listed regions or domains, as a result of the observed future energy trends, infrastructure needs and combination of several of the identified obstacles:

*BEMIP (Baltic Energy Market Interconnection Plan)*

The three Baltic States – and in terms of gas also Finland – are practically isolated from the EU energy markets. In electricity, the Baltic energy grids are synchronously connected to the Russian UPS (Unified Power System). As of today, there is only one asynchronous interconnection to the West between Estonia and Finland. New connections are planned with Finland, Sweden and Poland, but not yet all realised. In gas, all four countries depend on a single supplier, and in most cases through one import route, which raises security of supply concerns. This same supplier also has a stake in the TSOs of the countries. With no real functioning market, cross-border and additional import infrastructure needs (such as LNG) to improve market integration and security of supply cannot be met by market demand. Coordination between Member States, TSOs and regulators is necessary in order to align regulatory approaches – a barrier for further investments and market opening – that would allow a fair distribution of regional infrastructure development costs as well as benefits.

*Offshore grid in the Northern Seas*

Offshore wind is expected to be an important means to reach the EU's 20% renewable target. Potential for this energy source is mainly in the North Sea and neighbouring waters. At the same time, there is also an increased need for interconnection capacities between countries in the North (e.g. Norway, Sweden) and Central Europe (e.g. Germany, the Netherlands), both for more electricity trade and enhanced security of supply. This creates the need for an integrated offshore grid solution both to connect large amounts of offshore wind and ocean energy capacities and to function as an international interconnector.
The creation of such a new grid is subject to several important challenges: coordination among Member States and entities in charge of planning and execution (ministries,

[55] Concerning existing infrastructure, the cost for upgrading the Odessa-Brody pipeline capacity from 14.5 to 33 million tons per year (mta) was estimated at about 450-500 million euros, while upgrading the Adria pipeline from 9.8 to 14 mta would add another 70 million euros. Concerning new West-East interconnections, the Schwechat-Bratislava pipeline for example would require about 50 million euros investment for up to a capacity of 5 mta. (calculations done by ILF and Purvin&Gertz).

regulators, TSOs, developers etc.); designing a new regulatory scheme; defining appropriate market rules for multilateral investments; developing appropriate technical standards and operational solutions.

So far, Member States have adopted different approaches to develop their national offshore wind potential and the corresponding grid. National regulation encourages radial connections of wind farms with an onshore connection point, to maximise benefits while minimising project risks and costs (see Annex 4 for more details). Under these conditions, projects using innovative but riskier technologies (e.g. offshore voltage source conversion) and new grid designs involving more than two countries are difficult to realise, preventing further cross-border optimisation. Moreover, individual planning and building of wind farm connections makes the anticipation of future development needs difficult, which might lead to increased overall cost and environmental impact in the long term. Integrated solutions such as a meshed offshore grid, associated with appropriate cost-benefit allocation mechanisms, are lacking, preventing the full benefits of both renewables connection and electricity trade to realise[56].

Such a grid will only be possible with strong regional or even European level coordination and planning and the necessary technological developments (notably concerning direct current (DC) breakers and multi terminal control systems). The need for this coordinated approach has been identified by the countries that are participating in the North Sea Countries Offshore Grid Initiative (NSCOGI)[57]. It is finally important to note that this offshore grid development, together with the onshore wind development near to the coasts, will trigger major interconnection requirements with existing and new generation and hydro pumping capacities both in the North (Norway, Sweden) and the Alpine region (Austria, Switzerland).

*Renewables in Southern Europe and the Mediterranean*

In the Southern countries of the EU, solar energy will offer important new generation capacities, notably in France, Italy, Portugal and Spain. The role of solar electricity could still increase, if additional generation in Mediterranean third countries is imported into the EU through interconnections between Morocco and Spain or Tunisia and Italy. As for wind energy in the North, these new capacities will trigger major grid reinforcement and new interconnection investment needs in this region, especially concerning the Spain-France and the Italy-France, Italy-Switzerland and Italy-Austria links. As recent experience has shown, development of additional cross-border infrastructure in the regions has faced major difficulties in reaching public acceptance, leading to lengthy authorisation procedures and costly solutions. Concerning interconnectors between the EU and third countries, problems arise from the often complex political situation. In addition, questions remain concerning the applicable regulatory framework.

*New supply sources – Southern Corridor*

The objective of the development of the Southern Corridor is to further diversify sources and to bring gas and oil from the Caspian Basin and the Middle East to the EU. The projects in the Southern Corridor face on one hand the necessity of coordination between several Member States and with non-EU members, the establishment of a legal regime to transport gas through these territories and on the other hand the challenge to co-ordinate the timings to develop the up-stream resources and necessary infrastructure with the timings of the import infrastructure projects. At the same time, this is also the opportunity for the European Union to enter closer energy partnership with Central-Asian and Middle-East countries.

[56] Currently the analysis is not done at regional or European level, where these synergies could be identified. An integrated interconnector / offshore wind connection solution might cause different proportion of costs and benefits for the different actors.

[57] In December 2009, the Political Declaration of the NSCOGI was signed by 9 Member States (Belgium, the Netherlands, Luxembourg, Germany, France, Denmark, Sweden, the UK and Ireland). Norway joined the initiative in early 2010. The 10 countries are aiming at signing a Memorandum of Understanding by the end of 2010. The mission of the NSCOGI is to facilitate coordinated offshore electricity infrastructure development with a joint commitment in view of large offshore wind power development in the region.

*Central and South-East European interconnections*

Concerning gas, Central and Eastern EU countries, as well as South-East Europe (Energy Community countries) often depend on one single import source and hence limited, weak competition. Furthermore, they often depend on one single pipeline infrastructure both for oil and gas. Practically all of the problems identified in chapter 2.3 converge in this area: no complete implementation of internal energy market rules, missing infrastructure development due to lack of market development and vice versa, the lower creditworthiness of local companies due to their lower capitalisation, the effects of the economic crisis (thus deteriorating country risk ratings) and the higher exposure to external transit or supply risks. Furthermore, the investment need to meet the infrastructure standards set out in the security of gas supply regulation is very high in this region compared to the investment capacity of the concerned countries/companies, given current tariff levels and households' ability-to-pay.
Concerning electricity, challenges arise from the evolution of power flows and the need for further market integration in the countries of the region. North-South flows will rise in importance as new generation in Bulgaria, Hungary or Croatia will get connected to the network. East-West interconnections could need reinforcement, as new systems (Turkey, but also Moldova and Ukraine) join the continental synchronous system. Moreover, these systems will have to be connected to the dominant storage capacities in the Alpine region.

## 2.6. Key players and affected population

Various actors in the energy sector and beyond are affected by the proposal:

- Transmission and distribution system operators will be first and foremost affected, as any new initiative will touch upon planning and realisation of new transmission infrastructure;
- Operators and developers of existing and new power plants (including CCS) and electricity and gas suppliers, as a new policy will have an impact on the evolution of grid capacity;
- Member State governments, administrations and regulators who will be in charge of implementing any new rules related to tariff regulation, financing, planning and permitting;
- Energy consumers, as optimised and smarter grids will contribute to better balancing of supply and demand and hence to reduced and less volatile energy prices;
- Citizens in the neighbourhood of new infrastructure, that might be affected temporarily (construction) or permanently (local environmental or visual impacts etc.);
- EU citizens at large, as a new policy will contribute to making the energy system more reliable, competitive and sustainable in terms of environmental and climate impacts.

## 2.7. EU right to act

Under Article 194 TFEU, Union policy on energy shall aim at: (a) ensure the functioning of the energy market; (b) ensure security of energy supply in the Union; (c) promote energy efficiency and energy saving and the development of new and renewable forms of energy; and (d) promote the interconnection of energy networks. Energy transmission infrastructure (including an interconnected off-shore grid and smart grid infrastructure) has Trans-European, regional or at least cross-border nature or impacts. Member State level regulation is not suited and individual national administrations have no competence to deal with these infrastructures as a whole. They are therefore covered under Article 170 and 171 TFEU. Article 170 specifies that "the Union shall contribute to the establishment and development of trans-European networks in the areas of transport, telecommunications and energy infrastructures". Article 171 sets the obligation that "the Union shall establish a series of guidelines covering the objectives, priorities and broad lines of measures envisaged in the sphere of trans-European networks; these guidelines shall identify projects of common interest".

The Second Strategic Energy Review proposed that a new EU Energy Security and Infrastructure Instrument should be tabled to replace the existing TEN-E framework (policy and financing). At its extraordinary session in January 2009, the Transport, Telecommunications and Energy Council invited the Commission to "to carry out a thorough assessment of network interconnection, identify gaps, suggest action and to speed up the revision of the TEN-E framework with a view to considering the development of a comprehensive EU Energy Security and Infrastructure Instrument as suggested in the 2nd Strategic Energy Review." At its March 2009 summit, the European Council concluded that “Energy infrastructures and interconnections must be developed. To that end, the Commission, in cooperation with Member States, is invited to rapidly present the detailed actions required to realise the priority areas identified in the SER. […] The Commission is invited to present […] its proposal for a new EU Energy Security and Infrastructure Instrument.” This instrument will be dealt with in a legislative proposal following a communication on energy infrastructure priorities.

Moreover, the Second Strategic Energy Review stated that "a Blueprint for a North Sea offshore grid should be developed to interconnect national electricity grids in North-West Europe together and plug-in the numerous planned offshore wind projects."[58] In the conclusions of the Energy Council on 19 February 2009, the plans for the blueprint were endorsed with the small change that the scope was changed from North Sea to "the North Sea and North West Offshore Grid", thus clearly covering also the Irish Sea. In its conclusions, the Council also agreed to "promote a co-ordinated approach between Commission and Member States, where appropriate, in order to support in a cost effective way large scale deployment of offshore wind power in the European seas while preserving the reliability of the grid".

More recently, the Europe 2020 strategy[59] put again energy infrastructures in the forefront as part of the flagship initiative "Resource efficient Europe". It underlined the need to urgently upgrade Europe's networks towards a European "smart" supergrid, interconnecting them at the continental level, in particular to integrate renewable energy sources. It also highlighted the need to promote infrastructure projects of major strategic importance to the EU in the Baltic, Balkan, Mediterranean and Eurasian regions.

## 3. OBJECTIVES

The general objective of the initiative is to ensure **sufficient and timely infrastructure development across the EU and beyond** in order to:

- further develop the internal energy market so as to ensure reliable energy provision at affordable prices to European customers,
- ensure security of supply,
- meet the EU’s energy and climate targets.

In order to sustain infrastructure development, its main hindrances are to be tackled. The planned Communication on infrastructure priorities hence has the objectives to propose clear priorities and improve focus of EU action for all relevant energy infrastructure, reinforce regional co-operation and coordination, highlight the difficulties linked to permitting procedures and build public acceptance to help reducing planning and permitting uncertainties. Clear infrastructure priorities will also provide a political message towards third countries.

[58] COM(2008) 781 p. 5
[59] COM(2010) 2020, 3.3.2010

The abovementioned objectives are fully in line with the Europe 2020 strategy and in particular the "Resource efficient Europe" flagship initiative and support directly the achievement of the two binding targets of 20% share of renewables and 20% of greenhouse gas emission reductions by 2020. In addition, the uptake of smart grid technologies directly promotes energy efficiency. The objectives are furthermore consistent with the EU policies on competitiveness and innovation.

The objectives explained above are consistent with the Commission's on-going work to outline possible roadmaps for a transition to a low-carbon energy system by 2050. While the development of electricity and CO2 transport infrastructure is recognised as a key factor for success under almost any future scenario, uncertainties concerning future gas and oil demand do not reduce the need for infrastructure development in the near term future[60].

## 4. POLICY OPTIONS

In order to better analyse solutions to the main problems identified above, it is suggested to split the analysis in policy areas and propose separate options for each area (see Table 1). The policy options are evaluated against the criteria of effectiveness, subsidiarity and proportionality. The main criterion for effectiveness is how much adequate infrastructure investment the single options are likely to deliver. All the options are coherent with the overarching EU objectives, strategies and priorities. Based on this evaluation, the most effective and efficient options will be combined into a preferred policy set.

**Policy area A: Scope of the policy instrument**

Option 1: Business as usual (electricity and gas)

Option 2: Enlarged electricity and gas

Option 3: Enlarged electricity and gas, inclusion of CO2 networks and oil pipelines

**Policy area B: Design of policy instrument**

Option 1: Business as usual (project lists as today)

Option 2: Updated project list

Option 3: Limited number of priority projects/regional corridors and smart selection criteria

**Policy area C: Coordination**

Option 1: Business as usual (national approach, EU coordinators), voluntary regional structures

Option 2: EU coordinators and mandatory regional or thematic priority structures

Option 3: EU TSO

**Policy area D: Permitting**

Option 1: Business as usual (national competence), exchange of best practices

Option 2: Inclusion of projects of European interest in national priorities and application of fastest national procedure (where existing)

Option 3: National one-stop-shop approvals with streamlined time limits (5 years)

Option 4: New harmonised permitting scheme at the EU level

**Table 1: Policy options**

[60] Indeed, while the evolution of gas demand is uncertain until 2030 and even more so until 2050, gas is expected to have an increasing share until 2020, which is unlikely to drop dramatically after 2030 from a projected share of 22.4%-24.3% of total energy demand under the PRIMES reference scenario, especially if carbon capture and storage technologies develop. Similarly, the projected oil share of around 32% by 2030 is unlikely to drop drastically, especially considering its slow substitution in the transport sector.

## 4.1. Policy area A: Scope of policy instrument

All proposed options in this policy area are considered to meet the subsidiarity and proportionality principles.

**Option 1:** Business as usual: electricity and gas

This option would cover electricity, gas and olefin transmission infrastructure, gas storage and liquefied natural gas (LNG) infrastructure, as is the case with the current TEN-E policy.

**Option 2:** Enlarged electricity and gas

Under this option, the electricity infrastructure targeted would be enlarged to cover also smart grids and storage projects, in addition to the traditional transmission projects. Compressed natural gas (CNG) infrastructure would be added under the targeted gas infrastructure. This option can in principle be combined with all options of policy areas B, C and D.

**Option 3:** Enlarged electricity and gas, inclusion of CO2 networks and oil pipelines

This option would include electricity transmission, storage as well as smart grid technologies; gas pipelines, storage, LNG and CNG, as is the case in option 2. But it would also cover both CO2 transportation and oil pipeline infrastructure, thus overall energy transport infrastructure. This option can in principle be combined with all options of policy areas B, C and D. However, oil pipelines could a priori not be treated under option C3 (EU TSO, see below), as they are privately operated without central management through an independent TSOs.

## 4.2. Policy area B: Design of policy instrument

All proposed options in this policy area are considered to meet the subsidiarity and proportionality principles.

**Option 1:** Business as usual

The “business as usual” option would mean to continue with the TEN-E policy as it is, including the current project list divided into three categories and re-confirmation of the existing priority axes.

**Option 2:** Updated project list

Option 2 would mean to continue with the general TEN-E policy, but to revise and update the priority projects defined in the annexes of the decision and to possibly enlarge the scope under options 2 or 3 of policy area A (through ordinary legislative procedure). New projects would benefit from political support and an EU label, as is the case in the current TEN-E policy.

**Option 3:** Limited number of priority projects/regional corridors and smart selection criteria

This option would propose new broad priority areas and regional corridors of European interest, focusing on the main bottlenecks identified (see chapters 2.4 and 2.5), thus not fixing a list of projects beforehand. These broad priority corridors would be complemented with smart and transparent criteria for identifying projects in need of more focused attention at the regional or EU level. The approach is based on a European top-down (thematic or regional) perspective rather than on individual projects. This differs from the current approach laid down in the TEN-E guidelines, where the list of projects is fixed in the Annexes and has been identified bottom-up, reflecting Member States' national priorities. The criteria for the identification of projects should be based on the following principles and further discussed and refined with relevant stakeholders, so that the more detailed criteria can be included in the future legislative proposal[61].

Principles to be applied in the electricity sector would cover the major objectives of EU energy and climate policy: (1) contribution to security of electricity supply; (2) capacity to connect renewable generation and transmit it to major consumption centres; (3) increase of market integration and competition; (4) contribution to energy efficiency and smart electricity use.

The principles suggested for gas infrastructure are derived from the objectives of the EU energy and climate policy to improve security of supply and market development: (1) diversification, giving priority to diversification of sources, counterparts and in last place routes; (2) ratio of increase in interconnection level; (3) reduction of market concentration.

## 4.3. Policy area C: Coordination

**Option 1:** Business as usual

This option would continue the current approach based on largely national initiatives, with support from EU coordinators and voluntary regional structures for certain projects.

**Option 2:** EU coordinators and mandatory regional or thematic priority structures

While maintaining the involvement of EU coordinators, existing regional structures would be given the task of identification of concrete priority projects and implementation and monitoring of infrastructure priorities in a given region or sector, with the involvement of all relevant stakeholders (national administrations, National Regulatory Authorities, NGOs and TSOs). A compulsory framework would ensure that there is a regional view and that approaches do not remain fragmented at national level. The identification of the priorities would be linked to the criteria referred to under option B3.

There is already mandatory regional co-operation in the framework of the internal energy market rules (second and third package) in various areas: regional 10-year network development plans shall be prepared by the TSOs and national regulatory authorities co-operate within the "regional initiatives". The Regional Initiatives are currently under revision and a new proposal is expected in 2011. The overall EU optimum would be ensured through the already existing EU-level institutions such as ACER, the ENTSOs and regulatory for a. Building on the positive example of the BEMIP or the NSCOGI, the Commission may support ad-hoc regional co-operation on request, such as the Visegrad+ initiative to implement North-South interconnections in Central-Eastern and South East Europe. This solution would simplify the cooperation, build on synergies with other discussion areas (defined in the third package) and reduce the number of fora and meetings for all stakeholders. The constitution of regional initiatives under this option will be closely linked to the identification of priorities under policy area B.

**Option 3:** EU Transmission System Operator

The idea of a single European TSO for gas was raised by a group of EU gas companies and outlined also in the Green Paper. The European Parliament concluded that "*forward-looking initiatives, such as the European transmission system operator and the establishment of a single European gas network, should be encouraged*"[62]. The aim could be to build progressively independent companies to manage unified transport networks throughout the EU in gas, but also in electricity or CO2. The progressive merging of national networks, provided that it is organised in a manner compatible with competition law, would allow looking at network development from a truly EU perspective and enhance incentives to invest in infrastructure where it is needed regardless of national boundaries.

[61] As long as these detailed criteria have not been elaborated, an estimation of the precise number of projects qualifying or not qualifying under the new regime is not possible.

[62] European Parliament resolution of 3 February 2009 on the Second Strategic Energy Review (2008/2239(INI))

An EU TSO would facilitate more regulatory and technical standardisation and thus allow energy to cross borders more easily. This could lead to a situation where national regulators would not any more be capable to regulate transmission. A European regulator would be needed – a future role that could be played by ACER. Such a solution would also allow introducing “European transmission tariffs” to cover the TSO’s costs (and wider EU benefit).
In the case of electricity, such a TSO could also be charged with the design and implementation of integrated offshore grids or new European high-voltage long distance grid. For $CO_2$, this would also allow the up-front planning of an optimal $CO_2$ network.
These single EU TSOs would have to take into account all objectives of the EU energy policy (market integration, security of supply and the climate goals).
An EU TSO would become a monopoly and have a huge asset base. This would increase its creditworthiness and capacity to invest. To be a truly EU TSO, it should be given exclusivity over infrastructure development in the EU, which would eliminate the possibility for other market players to construct "merchant lines" dedicated to trade, where the owners reserve all or part of the capacity for their own use. Past experiences for strong monopolies demonstrate, however, that such a TSO would need to be closely regulated and monitored with full transparency in order to make sure that transmission costs are correctly allocated to the users and to prevent abuse of its dominant market position. No individual supplier should be allowed to acquire a controlling stake in the EU TSO in order to maintain its neutral position and non-discriminatory approach on the market.
It is also considered that the process towards an EU TSO may rather take place on a progressive and voluntary basis and that the Treaty does not provide the powers to impose this solution. This solution furthermore is unlikely to respect the principles of subsidiarity and proportionality, as strengthened or mandatory regional co-operation and infrastructure planning may lead to similarly effective results. <u>Therefore this option is discarded from further analysis.</u>

### 4.4. Policy area D: Permitting

**Option 1:** <u>Business as usual: national competences, exchange of best practice</u>

In this option (current TEN-E approach), national competences would be maintained, their obligation being to make best efforts to facilitate implementation of identified TEN-E infrastructure. They would be enhanced through the publication of national best-practice measures. Member States would apply these measures on a voluntary basis.

**Option 2:** <u>Inclusion of projects of European interest in national priorities and application of fastest possible procedure (where existing)</u>

This option would oblige Member States to include projects declared to be of European interest (PEI)[63] in their national priorities and to apply the fastest existing authorisation procedure (where these exist). The principles of subsidiarity and proportionality would be respected as this option does not provide for concrete procedures, which would be left to the Member States. This policy option would be applicable only in Member States where national priorities have been defined and where “fast-track” procedures exist. In the other Member States, “business as usual” would be maintained.

**Option 3:** <u>National one-stop-shop approvals with streamlined time limits</u>

The Presidency of the European Council invited the Commission in March 2007 "*to table proposals aiming at streamlining approval procedures*"[64], and industry expressed the need for EU measures to facilitate permitting procedures. This option would introduce a "one-stop-shop" permitting scheme for projects of European interest, under which all Member States

[63] NB: The definition of "project of European interest" could be revised and does not necessarily correspond to the currently used definition in the TEN-E guidelines.
[64] See European Council Presidency Conclusions of 8/9 March 2007, 7224/1/07 REV 1

would have to nominate a national contact authority. It would be left up to Member States, whether this authority would have decision making powers or be a coordination body where decision-making competence would remain with the competent authorities at national, regional, and/or local level. The one-stop shop would serve as a single interface between the project developer and the competent authorities. It could include more detailed objectives and specify the procedures to implement, including guidelines for public consultations, for minimum transparency requirements and for compensation of affected populations, as well as tacit approval or sanction mechanisms in case of delays. This option may ideally introduce a time limit of 5 years[65] for a final authorisation decision to be taken by the competent authority for a given project, feasibility of which still would need further assessment.
The introduction of a one-stop-shop would facilitate administrative procedures for project developers, and a time limit would lead to accelerated authorisation and more certainty in the process. Such an option would also apply to all Member States, not only to those where national strategies exist. Effects could further be enhanced by more specific guidelines. Tacit approval or sanction mechanisms would incentivise authorities to meet the timeline. With respect to the principle of proportionality, a legislative proposal would introduce general guidelines on the implementation of these measures. The concrete formulation of measures would still be left to the Member States, giving them freedom and flexibility how to meet the stipulated objectives.

**Option 4:** New harmonised permitting scheme at EU level

Option 4 would create a new harmonised permitting scheme, based on some of the measures as outlined under option 3 (one-stop-shop approach, time limit for final authorisation decisions), but with an aim at harmonising national approaches and giving final decision making power to the EU level in case problems cannot be resolved at Member State level. This should in certain cases allow overriding other interests on the basis of “European interest”, similarly to the “Déclaration d'utilité publique” (DUP) procedure applicable in certain Member States. The impact of this approach would be substantial because of the harmonised and hierarchical decision making approach. However, this policy option is unlikely to respect the principles of subsidiarity and proportionality, as the same results could be achieved by implementing option 3. Thus this option is discarded from further analysis.

## 5. ANALYSIS OF IMPACTS

We first analyse impacts for the business as usual (BAU) scenario, which includes the policy option 1 for each of the four policy areas. We then analyse the impacts of the different other options sequentially in each policy area A (scope), B (design), C (coordination) and D (permitting) as compared to BAU. The impact analysis for all options is based on qualitative and, where available, quantitative evaluation, covering, as relevant, economic (including administrative and compliance costs), social and environmental aspects. This methodology will allow identifying a limited number of policy sets for further, more detailed assessment and comparison.

### 5.1. Baseline ("business as usual")

Under business as usual (BAU), implementation of third internal market measures would help to resolve some of the identified problems in infrastructure planning and implementation of cross-border projects. The shortcomings of the current TEN-E instrument would however remain as such, with a focus on electricity and gas, rigid project lists, insufficient cross-border coordination and persistent delays in permitting. Nationally focussed and for technologies "conservative" tariff-setting would still render certain projects commercially not viable (see

[65] See recommendation of Priority Interconnection Plan (2007), COM(2006) 846 final/2, p.12f.

more details in Box 2). Moreover, due to the limited amounts of available EU funding and their focus on studies rather than works, only market based investments would take place, i.e. investments that are commercially viable under current market and regulatory conditions. Planning and permitting difficulties would lead to a remarkable mismatch between planned investments and investments actually carried out.

**Box 2: Methodology used for assessing the impact of identified problems on investment**

Quantifying the impacts of the problems identified under BAU is only possible to a limited extent, given the complexity of electricity and gas markets and corresponding infrastructure development. It was therefore decided to limit the quantitative analysis of impacts for this study to the following two dimensions, whose impacts can be estimated, based on existing theoretical and empirical evidence:
- uncertainties about technologies, imperfect tariff regulation and internal market, assessed through their impact on the commercial viability of projects;
- permitting, assessed through its impact on the realisation ratio of projects.

*Commercial viability*

While it is very difficult to circumscribe precisely the field of commercially viable projects in regulated markets such as those for electricity and gas transmission infrastructure, one can consider in a simplified manner that an investment concerning a new corporate financed asset is commercially viable if its cost-benefit analysis results lead the concerned TSO(s) to submit the investment project for approval to the regulator, for a given set of market and regulatory conditions (related to future utilisation rate forecasts, expected congestion rents etc. on the one hand, and a given set of rules concerning the asset base, regulated rate of return, amortisation etc. on the other hand).
Concerning project financed assets, commercial viability can also be tested through the ability of the project to secure commercial financing (equity and debt). One can further consider that regulated investments, which are approved by the regulator but afterwards not implemented by the concerned TSO because the regulated rate of return for the project is considered too low, given its expected risk and return profile, are not commercially viable.
Obviously, the field of commercially viable projects is a function of the applicable regulation, which itself should evolve with the implementation of the third internal market package. However, as described in chapter 2.4.2, the definition of commercial viability applied here takes already into account these evolutions.

Based on this definition and the investment needs analysis carried out in chapter 0, infrastructure investment needs and effective investment under BAU for **electricity** for the period 2010-2020 were calculated as follows:

- 70 bn€ for transmission infrastructure (source: ENTSO-E), out of which 28 bn€ are assumed to be dedicated to cross-border interconnections (source: KEMA). It was assumed that these investments will be commercially viable, although, given problems related to cost-benefit allocation for complex cross-border projects, some of them might actually not be so.
- 32bn€ for offshore grid infrastructure, based on an estimated 40 GW of installed offshore wind generation capacity by 2020 (source: ENTSO-E, OffshoreGrid study). Given the technological and regulatory uncertainties and the lack of incentives to develop optimised grid architecture, it was assumed that the corresponding investments will not be commercially viable, although some of them will happen under BAU. One must also note that first results from the OffshoreGrid study indicate that overall costs for connecting offshore wind farms and interconnecting electricity markets across the Northern Seas could be reduced with an optimised integrated grid infrastructure.
- 40bn€ for smart grid infrastructure in distribution and transmission networks (not related to smart metering). Given the technological and market design uncertainties as well as the lack of incentives for individual market actors to develop such grid infrastructure on their own, it was assumed that 50% of this investment (20bn€) will not be commercially viable.

Infrastructure investment needs and effective investment under BAU for **gas** for the period 2010-2020 were calculated as follows (source: PRIMES / DG ENER analysis):

- 28bn€ for import pipelines, out which an estimated 50% (14 bn€) will be built within the EU. It was assumed that intra-EU investments will be commercially viable under current market und regulatory conditions.

- 21bn€ for intra-EU interconnectors. It was assumed that intra-EU investments will be commercially viable under current market und regulatory conditions.
- 21 bn€ for storage. It was assumed that about 1/3 of these investments (7bn€) will not be commercially viable under current market and regulatory conditions;
- 1bn€ for reverse flow infrastructure. It was assumed that the corresponding investments will not be commercially viable under current market and regulatory conditions.

Given the technological, regulatory and market uncertainties surrounding CO2 transport infrastructure and the lack of incentive to build an optimised network, it was assumed that none of the estimated 2.5bn€ of investment needed over the period 2010-2020 will be commercially viable.

*Realisation ratio*

The impact of delays in planning and permitting on the effective commissioning of projects has been analysed based on stakeholder consultations as well as on empirical evidence from the literature. The 2005 "TEN-Energy-Invest" study concluded that the ratio "performed investments"/"scheduled investments" could be as low as 60% for certain electricity TSOs. It is highly likely that this ratio has further declined since, given the increased levels of local opposition and associated media focus on certain projects since 2005. This assumption seems to be validated when examining in detail the list of projects presented in the first TYNDP: despite conservative estimates for commissioning dates, delays are expected for about 20% of all projects identified and for about 50% of cross-border interconnectors in particular.

For gas infrastructure projects, consulted stakeholders have confirmed that planning and permitting problems exist but are less acute. Under BAU, it was therefore assumed that the realisation ratio is 50% of the total commercially viable investment for electricity and 90% for gas.

Based on the analysis described in Box 2, the total investment need amounts to 142 bn€ for electricity, out of which about 90 bn€ are assumed to be commercially viable under current market and regulatory conditions. The total investment need is 71 bn€ for gas, with 63 bn€ assumed to be commercially viable. For CO2 transport infrastructure, the number is 2.5 bn€. Applying the assumptions made on commercial viability and realisation ratios under BAU, electricity infrastructure delivery would reach about 30% (45 bn€ out of 142 bn€), while gas infrastructure delivery would reach about 80% (57 bn€ out of 71 bn€). No significant investment would take place for CO2 transport infrastructure. These figures are average figures taken as reference for simplification. In terms of overall economic impacts, BAU would therefore result in insufficient and sub-optimal development of electricity and gas transmission infrastructure, with an estimated investment shortfall of 113.5 bn€ over the period 2010-2020, corresponding to an overall infrastructure delivery rate of only 47%.

**Error! Reference source not found.** Table 2 below summarises these numbers:

| **Sector (investment 2010-2020, bn€)** | **Business-as-usual delivery** | **Commercially viable delivery** | **Total need** |
|---|---|---|---|
| **Electricity** | 45 | 90 | 142 |
| **Gas** | 57 | 63 | 71 |
| **CO2 transport** | 0 | 0 | 2.5 |
| **TOTAL** | **102** | **153** | **215.5** |
| ***Investment gap*** | ***113.5*** | ***62.5*** | ***0*** |
| **Total (%)** | 47% | 71% | 100% |

**Table 2: Business-as-usual, commercially viable and needed investment by sector 2011-2020**

Concerning **electricity**, transmission would continue to be optimised mainly at national rather than EU level, thus bearing significantly higher costs. For offshore grids in particular, certain projects would not be realised at all up to 2020, given delays and difficulties in the planning and permitting process, while for other projects, national, technologically mature and mostly radial connections to shore would be preferred over cross-border or technologically more advanced and integrated designs. Concerning onshore projects, planning and permitting delays and obstacles due to the imperfect internal market would affect in particular cross-border connections, maintaining certain transmission bottlenecks and hence congestion rents. Between 2006 and 2009, total congestion rents of 26 European electricity TSOs (EU-27 without CY, MT and UK plus Norway and Switzerland) have varied between about 1.2 bn€ and 1.95 bn per year[66]. The energy imbalances between Member State price zones would generate price differences, leading to significant social welfare impacts. These differences reached in 2008 on average between 15 and 29 €/MWh for 12 different interconnectors linking two Member States, with corresponding welfare losses estimated at over 3 bn€[67]. Increased price volatility and negative prices would be another consequence of insufficient transmission capacity in a given price zone.
Concerning both <u>economic and social impacts</u>, risks of system instability would increase due to higher balancing constraints, leading to more black-outs. Despite their relatively low probability, research shows that black-outs have unusually costs, notably for industry or services (production shortfalls, restarting of machinery, and damage to machinery or raw material) or households (loss of food, comfort and potentially free time). For the case of Germany, it has been estimated that overall costs could amount to 8-16 €/kWh, or about 30 to 150 times more than the current electricity price[68]. Therefore, even slightly deteriorated security of supply could induce macroeconomic losses of several billion euros for this country alone[69]. The social impacts of a black-out on society and daily life were felt clearly in November 2006 when a black-out, originated in North-West Germany, struck France, Austria, Belgium, Italy, Spain and even Morocco, leaving a total of about 15 million people without electricity for up to two hours. Among the concrete consequences affecting directly EU citizens were about 100 train delays in Germany and hundreds of passengers trapped in lifts in Paris due to the outage.

Concerning **smart grids**, BAU would lead to insufficient development, given their inherent risks, with associated negative impacts in terms of power outages, losses in the electricity system (technical, e.g. thermal losses, but also non technical, due to sub-optimal systems planning and asset management) and greater difficulty if not impossibility to integrate an increasing share of renewables and integrate and operate grids at European-level. But it would also prevent the EU from benefiting from directly quantifiable positive <u>economic impacts</u>: The French regulator CRE has estimated that with the implementation of smart metering the supplier switch capability for households will increase by a factor of 10 (50% instead of 5%). In the longer term, smart grids would contribute to price reductions on the electricity market by increasing transparency of supply and demand, hence reducing congestions, optimising system flows and providing the information needed for dynamic pricing. Moreover, the Bio Intelligence Report concludes that smart grids could reduce the EU's annual primary energy consumption in the energy sector by almost 9% by 2020[70], which equals to about 148 TWh of electricity. In 2010 prices, this amounts to annual savings of almost 7.5 bn€.

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[66] European Commission consultation on an Inter-TSO Compensation Mechanism, 2008; ENTSO-E
[67] "Influence of National and Company Interests on European Electricity Transmission Investments", Study by Matti Supponen, Helsinki University of Technology, August 2010
[68] German electricity prices were about 11c€/kWh for industry and 23c€/kWh for household customers during the second half of 2009 (Eurostat).
[69] "Hohe Versorgungszuverlässigkeit bei Strom wertvoller Standortfaktor für Deutschland", David Bothe and Christoph Riechmann in Energiewirtschaftliche Tagesfragen, 10/2008
[70] Pilot projects with smart metering in various European Member States have yielded annual reductions of consumption between 5 and 15%.

Lack of sufficient **gas** infrastructure would increase the probability of supply shortages or supply disruptions, or limit the possibilities to mitigate actual supply disruptions, in a context of decreasing domestic production (all over Europe) and higher import dependency. The example of the winter 2005/2006 in the UK illustrates the possible <u>economic impact</u> of supply shortages: due to higher prices, the extra cost paid by British consumers amounted to about 2 billion £[71] (about four times the value of the BBL pipeline between NL and UK). This shortage was mainly due to an infrastructure failure (storage burn) combined with insufficient import capacity to bring additional gas from other sources (through pipelines or LNG).
The economic damage caused by the January 2009 gas supply disruption in South East Europe has been estimated at 1.65 billion €[72] for Slovakia, Hungary, Croatia, Serbia and Bulgaria. This amount is by far higher than the total cost of all reverse flow projects and Central-Eastern European interconnector and storage projects included in the EEPR (around 1.2 bn€), which could have mitigated the supply disruption had they been operational at the time of the crisis. It was mainly inadequacies in gas transport which constrained flows (capacities, reverse flow capabilities, unusual routes, insufficient integration of gas networks in Central and South Eastern Europe), not lack of gas[73].
<u>Social impacts</u> on consumers could also be significant, especially in the winter. During the January 2009 gas crisis, many Bulgarian households remained without heating for up to 48 hours. While transit disputes, such as the one that lead to the above described crisis, have occurred on average 2 to 3 times each year in Europe over the past years[74], they resulted only twice (January 2006 and January 2009) in effective supply shortfall/disruption to the EU.

Lack of infrastructure would also increase dependency from only a few or a single source and hence hinder market integration and competition, leading to higher prices. This can be demonstrated by looking at the price evolution at existing trading hubs. North-West Europe seems to be rather well integrated, as the prices of TTF (Netherlands), Zeebrugge (Belgium), Gaspool or Net-Connect (Germany), PEG (France) and NBP (UK) generally seem to converge. However, the prices at the Italian PSV are constantly higher than the prices in the North-West. In Eastern Europe, liquid and transparent hubs are still under development (or to be developed), making the assessment of price differentials and missing links more difficult. However, as confirmed by stakeholder consultations, there are significant price differences between Central-Eastern European Member States[75]. These Member States (who joined the EU in 2004 and 2007) and the member countries of the Energy Community Treaty are therefore those exposed to the highest risks in terms of supply shortage or disruptions, lack of market and integration and therefore possible negative economic and social impacts.

Finally, the impacts of over- or under-investment in both electricity and gas infrastructures are asymmetric. As the cost of transmission is limited in the final energy price, over-investment in infrastructure will cause only a limited increase of the final price[76]. But a lack of infrastructure can cause energy shortages, disruptions or price increases with far higher economic and social impacts. For electricity in particular, transmission on average only amounts to about 10% of overall electricity cost. Investing in more generation and/or back-up capacity to avoid energy shortages and black-outs would result in higher overall costs for the concerned Member States compared to the construction of interconnectors to obtain EU-

[71] "Crossing Borders in European Gas Networks: The Missing Links", Clingendael Energy Paper, September 2009
[72] Estimates were provided by the concerned Member States to DG ENER.
[73] SEC(2009) 979 Impact Assessment of the gas security of supply regulation
[74] Such disputes arise for supplies coming from Russia through Ukraine, but also for those coming from Algeria through Morocco, the most recent one being the dispute between Belarus and Russia in July 2010.
[75] Note that even in the case of perfect interconnectivity and market integration, price differentials between distant regions would remain due to transport costs. However, prices should converge within a region if the market works well and sufficient interconnection capacities are available.
[76] For gas, transmission costs account on average for only 2-4% of the final gas price in Western Europe, although this share may be significantly higher in individual Member States, in particular in Eastern Europe.

wide or regional balancing, thus again increasing prices to final consumers. This effect would be even stronger, if missing transmission infrastructure prevents the development of renewable generation capacities and hence favours the use of fossil fuel based generation with higher fuel-dependent operating costs. This in turn could lead to increased problems of energy poverty for low income households, notably in Eastern Europe.

Concerning **CO2 transportation**, the BAU scenario would prevent any significant investment in networks and give rise to piecemeal development (at project or national level) with a high risk of future redundancy or bottlenecks in through-flow capacity (similarly to the electricity and gas grids) and limited market integration with a risk of higher energy prices in the long term.

Concerning environmental impacts, less infrastructure development would diminish negative local impacts for those directly concerned by new energy infrastructure projects, both temporarily (e.g. during the construction period for underground gas pipelines or electricity lines) and permanently (notably for overhead electricity lines or offshore grid infrastructure). It would also limit potential losses of biodiversity due to energy infrastructure crossing natural habitats. However, these impacts should be put in perspective with the negative global climate impacts generated by insufficient infrastructure development. Under BAU, lack of transmission infrastructure and smart grids would limit the possibilities to inject electricity from renewable sources into the grid to reach final customers, hindering the achievement of the 20% renewables target and preventing CO2 emission reductions, with the related consequences on the climate and the environment. Concerning renewables, given the difficulties and shortcomings identified above for offshore grid development, it is estimated that a significant share of the 32 bn€ of investments needed for offshore connection infrastructure by 2020 will not be realised. As demonstrated by KEMA and confirmed by ENTSO-E, reaching the 20% renewables target in 2020 will therefore be impossible, given the important contribution expected from offshore wind (over 12% of total renewable electricity production in 2020 or about 20% of the additional renewables capacity to be installed between today and 2020[77]). Concerning emissions, the Smart 2020 study estimates that global emissions could be reduced by 15% thanks to smart grids, mainly through their contribution to energy efficiency.
Similarly, absence of sufficient transportation capacity and lack of interconnection between CO2 producing sites in one Member State and CO2 storage sites in another Member State would slow down the uptake of CCS technologies, again maintaining higher CO2 emissions.
Gas supply shortages or disruption due to lack of infrastructure or alternative sources (such as LNG or CNG) would on the one hand lower CO2 emissions under BAU, as less gas is consumed. On the other hand however, one can realistically assume that gas would be replaced by other more emitting fossil fuels, typically oil or coal. The overall effect of insufficient gas infrastructure can be assumed to be higher CO2 emissions.
This environmental impact analysis is confirmed at the macro-level: cumulated CO2 emissions for the EU between 2010 and 2030 under the PRIMES baseline scenario (corresponding to BAU) are projected to be about 2,500 millions tons or over 3% higher than under the Reference scenario, where all necessary infrastructure is supposed to be operational.
In addition, the absence of additional energy infrastructures might also lead to negative local environmental impacts (e.g. air pollution), due to longer lifetimes or development of new capacities for non renewable, higher emission electricity generation capacities. In the case of **oil** transport, the alternatives to bringing additional oil to the EU in case of an oil supply disruption would be an increased tanker traffic in the environmentally sensitive Baltic Sea and the Bosporus to compensate a shortfall in the Druzhba pipeline system (the stop of the entire supply of this system would require to redirect approximately 60 million tons of crude

[77] DG ENER calculations

oil/per year[78]). Developing alternative supply routes would require investments, which might not happen without political support and awareness-raising at EU level.

## 5.2. Policy area A: Scope of policy instrument

From the impact assessment of the BAU scenarios, one can clearly conclude that major positive impacts are expected at the economic and social level from extending the scope of the policy instrument to new sectors in electricity (smart grids including storage) and gas (CNG), but also to CO2 transportation. This would address some of the uncertainties and the shortcomings of the current TEN-E framework, outlined in Chapter 2.3. Moreover, by focussing attention on new technologies such as smart grids, electricity storage or carbon capture and storage, extending the scope would also foster innovation in these fields. The extension to oil would also provide positive environmental impacts, by ensuring diversified oil supply routes to the EU to reduce the environmental risk related to increased tanker traffic on the Baltic Sea and in the Bosporus. Nevertheless, these would be limited to countries in Central and Eastern Europe supplied through the Druzhba pipeline system. Including all these new sectors in the scope of the policy instrument (option A3) is therefore the preferred option.

## 5.3. Policy area B: Design of policy instrument

Compared to BAU with a fixed and rigid project list defined in 2006, the update of this list (option B2) based on an enlarged scope (option A3) would allow taking into account new or changed priorities in terms of infrastructure development. This improved focus would have an overall positive impact, but would maintain the rigidity of a project list, which might again need adaptation in the future up to 2020 and beyond.

By contrast, a complete reform of the current approach (option B3), with a very limited number of broad priorities of European interest, no *ex ante* list of priority projects and smart and transparent selection criteria instead of the current three-tiered categorisation of projects, would yield far bigger positive economic, social and environmental impacts. Indeed, this option would allow focussing all attention on those priorities, which are of major European interest and for which EU intervention will be most beneficial, or on areas with strong innovation and high positive environmental impacts such as renewables' integration into the grid, smart grids, storage or CO2 transport. More generally, this approach based on European priorities would draw attention on economic and environmental trans-boundary and regional effects, while option B2 would be influenced more by national or even local level effects. Establishing smart and transparent selection criteria would minimise possible distorting effects on the internal market, by designing rules that are in line with current legislation and regulation. It would also allow evolution over time of the concrete support given to projects, optimising the use of the policy instrument even in the longer term. It is therefore considered to be the preferred option.

Transition from old guidelines projects list to new priorities and projects:

- Some projects are implemented or well underway (will be implemented by 2014).
- Some projects have been abandoned (proved unfeasible or uninteresting).
- Some will be taken up under the new priorities (if identified so by the respective regions).
- Projects, which lose their status acquired under the former guidelines, will do so because they are not of European, but of national or sub-regional interest, and should be promoted at these respective levels.

[78] "Technical aspects of variable use of oil pipelines coming into the EU from third countries", feasibility study by ILF and Purvin & Gertz

## 5.4. Policy area C: Coordination

As seen in chapter 2.2 and 2.3, the current TEN-E design with voluntary regional structures and EU coordinators has not provided all the necessary incentives for effective regional coordination and rapid implementation of cross-border infrastructure projects. Option C2 with mandatory regional structures and, where necessary, EU coordinators, would have significant positive impacts in terms of infrastructure development and is therefore considered as the preferred option compared to BAU. These regional structures would be particularly positive for projects with a clear regional delimitation such as the offshore grid in Northern Europe or the development of a gas corridor in South-Eastern Europe. They would also contribute positively to market integration and better functioning of regional markets. Their negative impacts in terms of administrative burden would be very limited to the meeting and coordination requirements created for various actors (national governments, regulators, TSOs, energy companies) through the newly established or extended regional structures. As existing regional structures, for example the so-called Regional Initiatives, would be used for this task, no additional administrative costs are expected.

## 5.5. Policy area D: Permitting

Both measures would introduce more efficiency in the decision making process by clarifying existing rules and ways or recourse, optimising the number of steps needed for a given decision to be taken and reducing as much as possible delays for each of these steps. While BAU is expected to lead to very limited streamlining and acceleration of permitting procedures only, option D2 would allow an accelerated treatment for European priority projects in those countries where priorities have been defined or where fast-track procedures exist. It is considered that this would partially shorten the delays observed under BAU and allow improving infrastructure delivery significantly in the electricity sector by raising the ratio "performed investments"/"scheduled investments" for the period 2010-2020 from 50% to 75%. In the gas sector, the effect would be more limited (from 90% to 95%). This would considerably increase infrastructure investment from 102 bn€ under BAU to 130 bn€ over the period 2010-2020.

The one-stop-shop approach (option D3) however would further facilitate administrative procedures and, combined with the limit of 5 years for a final authorisation decision to be taken by the authority for a given project, accelerate permitting and increase project delivery compared to the investment needs. It is assumed that 100% of the scheduled market based investments in electricity, gas and CO2 transportation would be realised during the period 2010-2020. The additional investment due to option D3 would be about €53bn compared to BAU, further increasing infrastructure investment to 155.5 bn€, with most of the contribution coming from the electricity sector, where the problems due to delays in planning and permitting are biggest..

The table below summarises the realisation rates assumed under BAU and with both options D2 and D3:

| Sector | Selected scenarios | Realisation rate assumption (% of total investment[1]) |
|---|---|---|
| Electricity | business as usual (D1) | 50% |
| | fastest national procedure (D2) | 75% |
| | one-stop-shop (D3) | 100% |
| Gas | business as usual (D1) | 90% |

| Sector | Selected scenarios | Realisation rate assumption (% of total investment[1]) |
|---|---|---|
| | fastest national procedure (D2) | 95% |
| | one-stop-shop (D3) | 100% |

**Table 3: Realisation rates under different scenarios (2010-2020)**

Concerning the macroeconomic impacts assessed using the E3ME model, both options would have significant positive overall effects on GDP and employment compared to BAU, with a cumulative effect of +0.42% of GDP and 410,000 additional jobs over the period 2011-2020 for option D3 (see Annex 3 for more details). This would correspond to a net cumulative increase in GDP of about 8.8 bn€ over the period[79]. The positive impact of option D2 would only be about half (+0.22% of GDP, about 150,000 additional jobs). In any case, the additional investment made possible would have positive impacts on small and medium enterprises, through the need for more employment generated in construction, mechanical engineering and business services. This would in turn increase incomes and household spending, confirming the positive social impacts of the policy.

Contrary to policy areas A and B and C, policy area D would have considerable impact on the administrative burden and compliance cost for both companies and national administrations compared to BAU. The industry repeatedly pointed out reduced administrative burden as a major desired change. Option D2 would simplify procedures and reduce administrative burdens only for projects in those Member States, where national priorities and fast-track procedures exist. The national "one-stop-shop" of option D3 however would reduce the amount of interlocutors for project promoters to a single identified authority per Member State, as opposed to the current situation where the number of authorities can reach up to 20, yielding the largest positive administrative impact. It must be noted however that, while option D2 is assumed to be easy to comply with, option D3 would create compliance costs for Member State governments in terms of national transposition of new rules, re-design of existing permitting procedures and re-organisation of authorities in charge of these procedures. While this option would also necessitate more administrative resources to process permitting for projects of European interest, it is not considered that this would lead to crowding out effects when compared to the processing of national projects, given the limited number of projects concerned.

Concerning environmental impacts, it must be underlined that both options D2 and D3 do not aim at reducing environmental standards for the evaluation of energy infrastructure projects. The compliance with EU environmental legislation is extremely important for the smooth implementation of energy infrastructure projects. All projects, if so required, will be subject to the appropriate environmental assessment in accordance with existing EU legislation (mainly SEA directive[80], EIA directive[81] Habitats directive[82] and Water framework directive[83]), as is already the case in the current TEN-E guidelines. As a result, certain projects might have to change their technology choice (e.g. from overhead line to underground cable or special measures for gas pipelines in order to be able to cross Natura 2000 sites; direct current instead of alternating current to reduce the size of power poles). Others would have to change their routing or to adopt measures in order to prevent and mitigate the possible

[79] Based on 2000 prices, the cumulative investment taking place under business as usual between 2011 and 2020 is about 73.9 bn€ (down from 89 bn€ in 2008 prices), while it is 117.8 bn€ under S1, yielding a difference of 43.9 bn€. Comparing this number to the cumulative annual GDP increase of 52.7 bn€, one obtains the net absolute GDP impact in 2000 prices.

[80] Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment

[81] Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment

[82] Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora

[83] Directive 2000/60/EC establishing a framework for the Community action in the field of water policy

adverse effects on the environment or, if not possible, to compensate negative impacts, in particular on the conservation objectives and integrity of Natura 2000 sites.

Following this assessment, it is considered that option D3 would be the most effective, while option D2 would imply lower compliance costs at Member State level.

However**,** the Communication covered by this impact assessment will only consider principles to make permitting procedures more efficient and transparent, whereas concrete rules to achieve this in the Member States will only be proposed in the Energy Security and Infrastructure Instrument to be tabled in 2011. A more detailed impact assessment will be prepared for this instrument, providing for an in-depth assessment of the different policy options with regard to the sectors covered, their compatibility with national legal systems and their compliance with the principle of subsidiarity, taking into account the importance of transparency and public acceptance. It will also include an analysis of the administrative burden and compliance costs for each policy option. It must be noted that these rules concerning permitting will only cover electricity transmission infrastructure as well as gas infrastructure transmission and storage infrastructure. Smart grid projects, which do not involve large visible infrastructure investment with high environmental impacts, and CO2 transport projects, which will see only limited investment up to 2020, should not be covered under these new rules.

In view of the next impact assessment, a study has been launched and will deliver first results by May 2011. The study will analyse the legal and regulatory framework as well as the effective practice concerning planning and permitting for electricity and gas infrastructure (covering spatial planning, environmental protection and public consultation rules), on which procedures and decisions are based. It will in particular assess the number and tasks of the authorities involved during each step of the permitting and licensing for typical infrastructure projects, as well as their respective level (local, regional, national).

Based on this analysis, the study will make recommendations for improving the existing legal, regulatory and incentive framework at EU level, taking into account differences in the Member States, notably in terms of legal systems and local acceptance. The recommendations will pay due respect to the impact of the solutions proposed in terms of simplifying and accelerating permitting procedures, and their viability in terms of how administrations will be able to implement them technically and legally. The recommendations will further be reflected against the principles of proportionality and subsidiarity.

In addition to the study, extensive stakeholder consultations, involving national administrations, TSOs and NGOs are foreseen. A dialogue with representatives from Member States where accelerated procedures have been or are about to be implemented has been initiated to enquire about best-practices and compliance costs incurred.

## 6. COMPARISON OF POLICY OPTIONS AND CONCLUSION

The four different policy areas, with between 2 and 3 maintained policy options for each, can be combined in numerous ways. In addition to BAU (analysed in the previous chapter), there are 8 possible policy sets combining different policy options in each area: 2 in area A, 2 in area B, 1 in area C and 2 in area D. However, the impacts of the different options within one policy area can be independent of those of another policy area. On the one hand, the scope of the policy instrument (policy area A) does not influence the effectiveness of the design of the instrument (policy area B); and the coordination between regional players (C) will impact each sector independently of the number of sectors targeted (A). On the other hand, while the impacts of the different permitting schemes (D) on the speed of project implementation will not be affected by a variation in scope (A), it is likely that certain permitting policy options will be more effective if combined with certain options of policy instrument design (B) or coordination (C).

The following table summarises the main impacts of each maintained policy option presented in chapter 5 in terms of economic, social and environmental impacts:

| | Economic impacts | Social impacts | Environmental impacts |
|---|---|---|---|
| **A: Scope** | | | |
| A1 | - more power losses, more energy consumption and less transparency for the consumer due to insufficient smart grid<br>- limited innovation in new technologies such as electricity storage, smart grids, CCS | | - higher air pollution and CO2 emissions (due to limited development of renewables, smart grids, CCS)<br>- higher environmental risks in case of oil supply disruption (due to increased oil tanker traffic) |
| A2 | - slightly diminished negative impacts compared to A1, notably for new technologies such as smart grids, electricity storage and CNG | | - higher air pollution and CO2 emissions (due to limited development of CCS)<br>- higher environmental risks in case of oil supply disruption (due to increased oil tanker traffic) |
| A3 | - best coverage of all sectors, in line with energy and climate policy objectives | | - air pollution reduction and less CO2 emissions<br>- more nuisance and negative local environmental impacts (due to additional infrastructure development) |
| **B: Design** | | | |
| B1 | - insufficient adequate transmission and storage capacity due to rigid, suboptimal priority setting, leading to congestion rents, price differences, price volatility<br>- increased risk of electricity black-outs or gas supply shortages / disruptions | - negative impacts on both electricity and gas consumers in case of black-outs/shortages<br>- energy poverty due to higher energy prices | - local nuisance and environmental impacts limited<br>- more CO2 emissions |
| B2 | - reduced impacts compared to B1, due to slightly improved priority setting | - slightly reduced impacts as compared to B1 | - slightly diminished effects as compared to B1 |
| B3 | - significant positive impacts on market (price convergence, lowering effect on prices) and security of supply<br>- significant development of renewables, smart grids, electricity storage and CCS, in line with energy and climate policy objectives | - reduced security of supply risks and lowering effect on energy prices beneficial to final consumers | - increased local nuisance and environmental impacts<br>- lower CO2 emissions |
| **C: Coordination** | | | |

| | | | |
|---|---|---|---|
| C1 | - insufficient cross-border infrastructure investment, insufficient market integration and bigger risks to security of supply | - negative impacts on both electricity and gas consumers in case of black-outs/shortages<br>- energy poverty due to higher energy prices | - local nuisance and environmental impacts limited<br>- more CO2 emissions |
| C2 | - more cross-border infrastructure development and optimised design, better (regional) market integration<br>- very limited administrative burden for various stakeholders | - reduced security of supply risks and lowering effect on energy prices beneficial to final consumers | - more CO2 emission reduction (e.g. through focus on offshore grids, CCS) |
| **D: Permitting** | | | |
| D1 | - significant delays in infrastructure delivery, insufficient development | | - local nuisance and environmental impacts limited<br>- more CO2 emissions |
| D2 | - reduced delays in infrastructure delivery, improved development<br>- positive effect on GDP (+0.22% over the period 2010-2020)<br>- limited administrative cost | - positive impact on job creation (+150,000 over the period 2010-2002) | - more local nuisance and environmental impacts than in D1<br>- CO2 emission reduced compared to D1 |
| D3 | - full delivery of commercially viable infrastructure projects<br>- significant positive impact on GDP (+0.42%)<br>- less administrative cost for operators<br>- significant compliance cost for national administrations | - significant positive impact on job creation (+410,000) and, to a lesser extent, SMEs | - more local nuisance and environmental impacts than in D2<br>- CO2 emission reduced compared to D2 |

As summarised above, the combination of options with the largest positive impacts would be A3, B3, C2 and D3, noting that the policy area of permitting will still have to be analysed more in depth. While BAU would lead to only 102 bn€ of investment, leaving an investment gap of 113.5 bn€, the most effective policy set as described above would significantly raise infrastructure delivery, with an investment level of 155.5 bn€. Our analysis also shows that this policy set would be most beneficial in economic, social and environmental terms.

It must however be noted that even the most effective policy set would deliver 60 bn€ less than the identified investment need of 215.5 bn€. Indeed, the mere enlargement of the scope, as well as the proposed reforms on the design of the policy instrument, regional cooperation structures and permitting, will not, *ceteris paribus*, close the remaining huge investment gap and will not make those projects bankable, which are commercially non viable under BAU market and regulatory conditions. This applies in particular to certain cross-border electricity grid, smart grid[84] and offshore grid infrastructure, to gas cross-border, reverse flow and storage infrastructure and to certain CO2 transport infrastructure. At the same time, the potential for tariff increases to be able to create the regulatory conditions to

[84] First studies and experiences do highlight the long-term economic viability of smart metering deployment alone. The UK Department for Energy and Climate Change (DECC) has estimated that fitting 26 million homes with smart meters by 2020 would cost over 8 bn £. But this cost would be more than compensated for by 14.5 bn £ of savings in operational costs for power companies and lower bills for customers. However, the corresponding "smart" investments on the grid are not currently covered by the market.

cover these investments is limited, given the investment amounts at stake[85]. Therefore, one could expect significantly higher positive impacts under a policy set using public funding or dedicated regulatory measures to enable the implementation of all projects of European interest, including those, which are not commercially viable[86]. Establishing principles for the cost-allocation across borders could solve the issues where the commercial viability of a project is due to its uneven cost-benefit allocation to users. Regulators could agree on common principles in relation to cost-allocation of interconnection investments and related tariffs. In electricity the development of long term forward markets for cross-border capacity should be explored, whereas in the gas sector the investments costs could be allocated to TSOs in neighbouring countries, both for normal (based on market-demand) investments as well as those motivated by security of supply reasons. The Commission plans to put forward, in 2011, a proposal or guidelines to address cost allocation of major technologically complex or cross-border projects, through tariff and investment rules. Where a higher rate of return would be required to match the project risks and thus make them bankable, a regulatory approach could also be envisaged. Public funding could be explored for those areas, where the above-mentioned measures would fail. However, this needs detailed further analysis which will be included in the Impact Assessment to be prepared for the EU Energy Security and Infrastructure instrument.

## 7. MONITORING AND EVALUATION

Specific indicators to monitor the evolution of the policy will be:

- The number of projects constructed, under construction or commissioned by given target dates such as 2015, 2020 and 2030, compared to the number of projects identified as being of European interest. This indicator could also be measured in terms of installed capacity and length of new power lines or gas pipelines and capacity of other new electricity and gas infrastructure (storage, LNG/CNG).
- To measure diversification of gas imports: the share of each import source and their concentration within the overall import (at national, regional and EU level), for example through the Herfindahl index[87].
- To measure the integration of renewables: the share of (variable) electricity produced from renewable sources in the overall electricity generation. This will be monitored through the bi-annual reports Member States must submit to the Commission under article 22 of the renewables directive.
- To measure market integration: the interconnection level between Member States and the evolution of energy prices. Concerning electricity, interconnector capacity defined as the ratio between import capacity and installed generation capacity in a given Member State could be used, as well price differentials observed between international interconnectors. Concerning gas, prices at major European hubs could

[85] There are strong signs that energy prices will increase in the short and medium term to respond to changes in the EU's energy system. In comparison to investments linked to increased electricity generation from renewables and investments in distribution grids, the impact of grid investments is forecasted to be minor. ENTSO-E has calculated that 100 bn € of transmission investment over the period 2010-2020 would represent only about 2% of bulk power prices. However, the combined impact of all needed investments on prices could be significant. The UK energy regulator (OFGEM) for example has calculated that prices could increase over the next 10 years by as much as 25%, while France has discussed a price increase of 20% over three years during 2009.

[86] The E3ME model confirms that such funding, if compensated e.g. by a small increase in direct taxation rates, would be revenue neutral at macroeconomic level compared to full funding of all the investment through higher energy prices.

[87] The Herfindahl index, also known as Herfindahl-Hirschman Index or HHI, is a measure of the size of firms in relation to the industry and an indicator of the amount of competition among them. It is defined as the sum of the squares of the market shares of the 50 largest firms (or summed over all the firms if there are fewer than 50) within the industry, where the market shares are expressed as fractions. The result is proportional to the average market share, weighted by market share. As such, it can range from 0 to 1.0, moving from a huge number of very small firms to a single monopolistic producer.

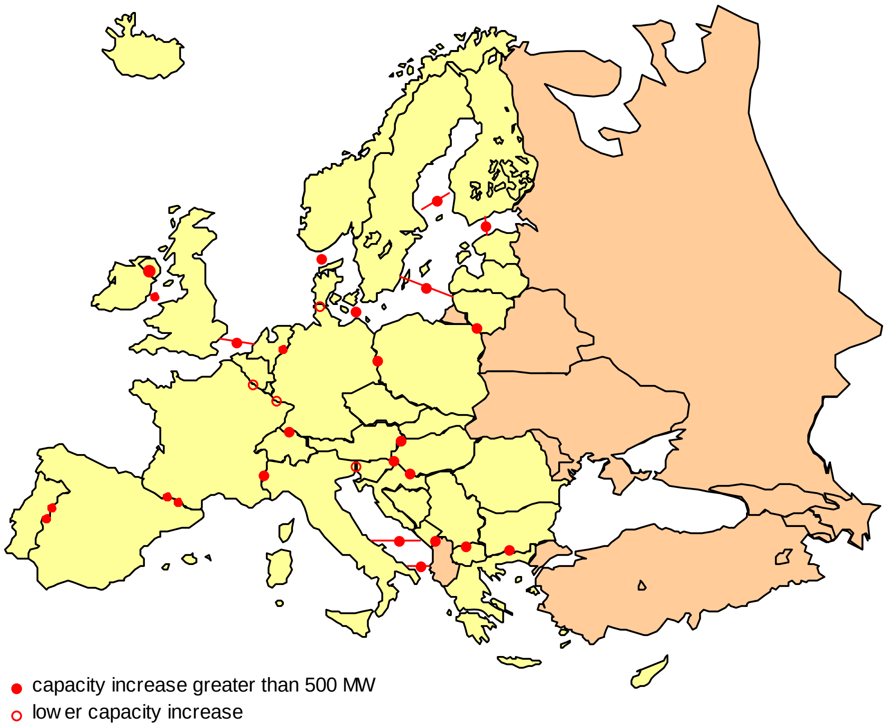
be used. Price monitoring is already being done by DG ENER's Energy Market Observatory.

- To measure the adoption of smart grid technologies: the share of grid infrastructure (including lines, converter stations, substations etc.) equipped with new communication technologies compared to the total infrastructure for a given TSO as well as the number of electricity costumers having signed up to smart grid enabled services.
- To measure security of supply of gas: the compliance with the N-1 and reverse flow standards will be monitored under the security of gas supply directive.
- To measure progress concerning permitting: the average duration of authorisation procedures for projects of European interest compared to the average duration of procedures for all infrastructure projects. This activity could be carried out by the ENTSOs.

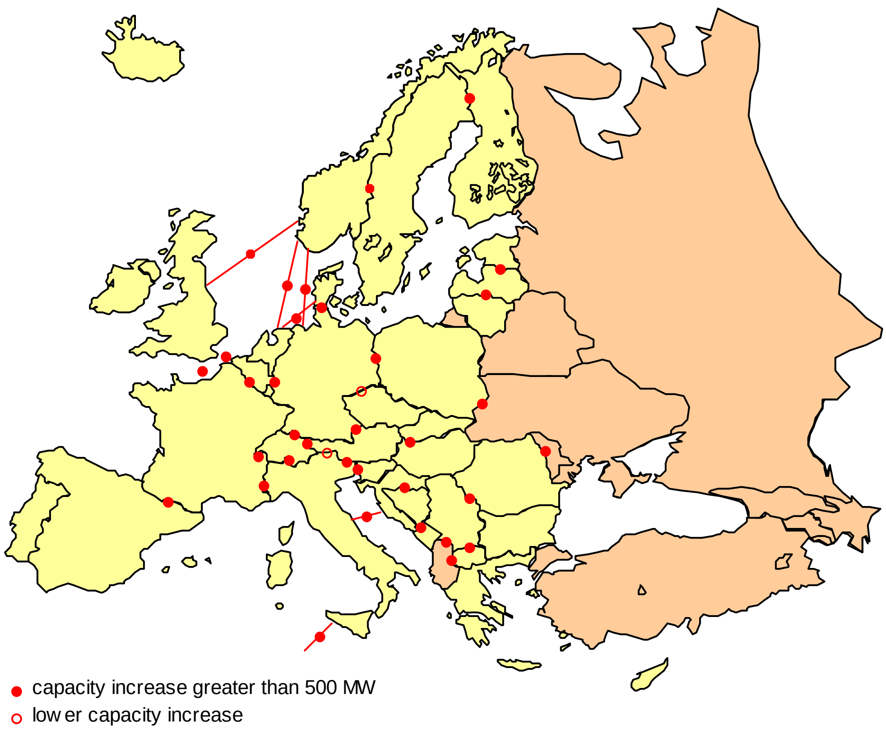
For monitoring and evaluation, like in the past, the Commission would assess the evolution via an implementation report on a bi-annual basis.

## ANNEX 1: ELECTRICITY TRANSMISSION CAPACITY INCREASES FOR THE PERIOD 2010-2015 AND 2015-2025

**Major transmission capacity increase in Europe in the next 5 years (mid-term)**




**Major transmission capacity increase in Europe in 2015 and beyond (longer term)**




Source: ENTSO-E

## ANNEX 2: CURRENT FINANCING OF TEN-E PROJECTS

Investments in infrastructure are mainly financed from private sources, whereby the TSOs' own resources can vary between 20% and 100% of the total investment depending on the risks and the scale of the overall investment. The rest is typically covered by loans from commercial banks and international financial institutions. Partnerships with companies active in the gas and power sector, other than TSOs, may offer additional capital in the form of equity participations. Energy infrastructure can be corporate financed or project financed. The involved risks are different. As a general rule, if a project lies within the TSOs' own network and is mainly linked to domestic transmission or distribution, TSOs will invest at their own risk and cover the investment from their own corporate sources. Larger mid-stream (gas) and cross-border (gas or electricity) projects are often project-financed, with special purpose companies set up for them. Member States in most cases do not participate directly in financing the of energy infrastructure and in particular TEN-E projects.

EU-funded support to TEN-E projects was based so far on the following instruments:

- TEN budget of 155 mln € for the period 2007-2013 (see chapter 2.2): Although the maximum co-financing rate is up to 50% for studies and 10% of eligible costs for works, it has so far rarely amounted to more than 0,01-1% of the total investment cost of a project.
- The European Investment Bank plays an important role in the implementation of the TEN-E projects. In 2007-2009 the financial envelopes providing senior loans amounted to 2.561 bn€ and 3.407 bn€ respectively for gas and electricity projects.
- In recognition of their social and economic importance, energy infrastructure projects have risen in priority in other EU funding sources, including the Structural Funds, Instruments for Pre-Accession (IPA) and European Neighbourhood Policy (ENPI/NIF) as well as the RTD Framework Programme. These programmes have a significantly larger budget than TEN-E for energy-related measures. However, from a total sum of 1.33 bn€ available under the structural funds for 2007-2013, only a fraction has been allocated to projects so far: 0.7% (7.5 mln €) for gas and 0.04% (12,000 €) for electricity. This is mainly due to the same difficulties as identified in chapter 2.3.
- In 2009, the Council agreed exceptionally to allocate 3.98 bn€ to energy infrastructure and technology through the European Energy Programme for Recovery (EERP), out of which 2.365 bn€ went to electricity and gas infrastructure projects. These funds targeted projects where delays caused by credit withdrawal would not only have been detrimental to the EU's security of supply, and therefore to future economic growth, but would also have had a serious impact on employment and skills in the energy and construction sectors. The remaining funds were aimed at the introduction of renewables (offshore wind, 565 m€) and other low carbon technologies (CCS, 1.05 bn€) into energy networks. For the supported offshore grid projects, a European added value was required, namely an "innovation component of large scale projects with cross-border significance", suggesting that "Such projects should include an integrative approach for interconnecting offshore wind power to provide transmission capacity in view of trading electricity between Member States." A large proportion of EERP funding will benefit the most mature Trans-European energy infrastructure projects, in order to speed up and secure investments and accelerate their realisation.

## ANNEX 3: E3ME MODELLING SCENARIOS AND RESULTS

### 1. Presentation of E3ME model

The E3ME model was used to carry out a more advanced macro-economic analysis of the impacts of the different policy options examined in chapter 5. E3ME is a computer-based model of Europe's economic and energy systems and the environment. It was originally developed through the European Commission's research framework programmes and is now widely used in Europe for policy assessment, for forecasting and for research purposes.

The structure of E3ME is based on the system of national accounts, as defined by ESA95 (European Commission, 1996), with further linkages to energy demand and environmental emissions. The labour market is also covered in detail, with estimated sets of equations for labour demand, supply, wages and working hours. In total there are 33 sets of econometrically estimated equations, also including the components of GDP (consumption, investment, international trade), prices, energy demand and materials demand. Each equation set is disaggregated by country and by sector.

E3ME's historical database covers the period 1970-2008 and the model projects forward annually to 2050. The main data sources are Eurostat, DG ECFIN's AMECO database and the IEA, supplemented by the OECD's STAN database and other sources where appropriate. Gaps in the data are estimated using customised software algorithms.

The other main dimensions of the model are:

- 29 countries (the EU27 member states plus Norway and Switzerland)
- 42 economic sectors, including disaggregation of the energy sectors and 16 service sectors
- 43 categories of household expenditure
- 19 different users of 12 different fuel types
- 14 types of air-borne emission (where data are available) including the six greenhouse gases monitored under the Kyoto protocol.
- 13 types of household, including income quintiles and socio-economic groups such as the unemployed, inactive and retired, plus an urban/rural split.

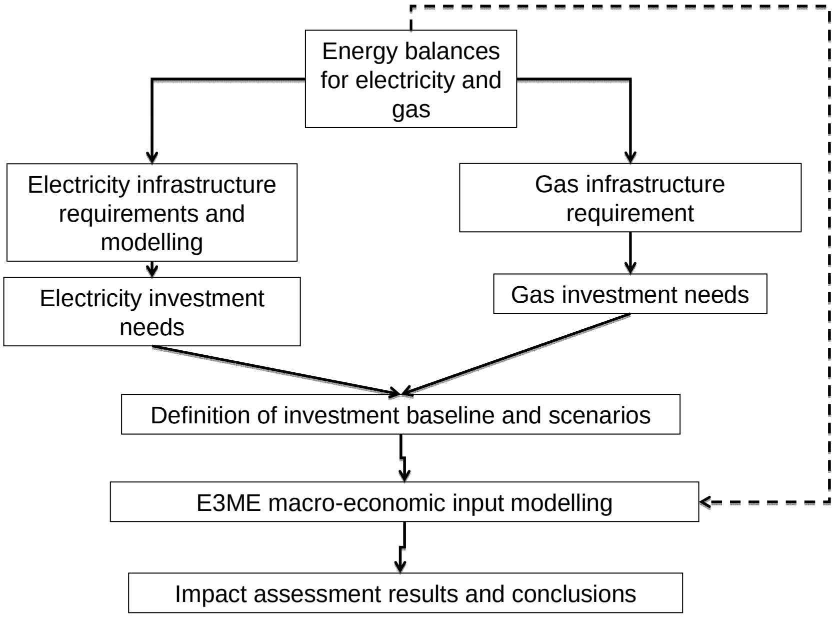
Typical outputs from the model include GDP and sectoral output, household expenditure, investment, international trade, inflation, employment and unemployment, energy demand and CO2 emissions. Each of these is available at national and EU level, and most are also defined by economic sector.

The econometric specification of E3ME gives the model a strong empirical grounding and means it is not reliant on the assumptions common to Computable General Equilibrium (CGE) models, such as perfect competition or rational expectations. E3ME uses a system of error correction, allowing short-term dynamic (or transition) outcomes, moving towards a long-term trend. The dynamic specification is important when considering short and medium-term analysis (e.g. up to 2020) and rebound effects[88], which are included as standard in the model's results.

More detailed information on the E3ME model can be found in the impact assessment study done by COWI, Cambridge Econometrics and KEMA.

[88] Where an initial increase in efficiency reduces demand, but is negated in the long run as greater efficiency lowers the relative cost and increases consumption.

The graph below depicts the methodology applied to analyse the macroeconomic impacts of infrastructure investment in the framework of this study.




## 2. Policy sets

Different combinations of policy options (policy sets) were designed to analyse the macroeconomic impacts of various policy options[89]. In addition to policy set (S1) combining all preferred options (A3, B3, C2 and D3), a policy set (S2) was established, where option D3 is replaced by option D2 to diminish Member State compliance costs. For the sake of comparison, an additional policy set (S3) was designed to take into account possible measures targeted at non commercially viable projects. Indeed, S3 assumes public support or regulatory measures (such as guidelines on remuneration of non commercially viable projects including for example capacity payments, compensation schemes, rate-of-return bonuses) to ensure full delivery of all investments needed, including non commercial projects. The three abovementioned scenarios (S1, S2 and S3) were compared to business as usual, using the E3ME model.

The following table summarises the **policy sets** and the **investment assumptions**[90] made for their development, based on existing studies and expert analysis:

[89] It must be noted that these policy sets could not stylise the impacts of the options in each policy area, but mainly relied on assumptions arising from policy area A and D.

[90] Under BAU and policy sets S1 and S2, total investment corresponds to the investment assumed to be commercially viable under current market and regulatory conditions, not taking into account potential delays due to planning and permitting, which can reduce the realisation rate for a given period. Only under policy set S3, which assumes support targeted both at commercially viable and non-commercially viable projects, total investment corresponds to the identified investment need.

| Scenarios | Input assumptions for E3ME modelling (investment in the EU only) | |
|---|---|---|
| **Business as usual**<br>(A1, B1, C1, D1)<br><br>(alias *CS1*) | Investment electricity (including smart grids):<br>45BN€ (50% of total market based investment needs)<br>Investment gas:<br>44.7BN€ (90% of total market based investment needs)<br><br>**TOTAL: 89.7BN€** | <br>2010-2020<br><br>2010-2020 |
| | Financing:<br>Energy price + x M€ EU funding[91] (60% electricity, 40% gas) | |
| **Policy set S1**<br>(A3, B3, C2, D3)<br><br>(alias *CS4*) | Investment electricity transmission:<br>90BN€ (100% of a total commercially viable needs)<br>Investment gas:<br>49.7BN€ (100% of a total commercially viable needs[92])<br><br>Investment CCS: 2.5BN€<br><br>**TOTAL: 142.2BN€** | <br>2010-2020<br><br>2010-2020<br><br>2015-2020 |
| | Financing method:<br>Energy price + x M€ EU funding (11/30 gas, 11/20 electricity, 1/12 CCS) | |
| **Policy set S2**<br>(A3, B3, C2, D2)<br><br>(alias *CS3*) | Investment electricity transmission:<br>68BN€ (75% of a total commercially viable needs)<br><br>Investment gas:<br>47.2BN€ (95% of a total commercially viable needs)<br><br>Investment CCS: 2.5BN€ – 2015-2020<br><br>**TOTAL: 117.7BN€** | 1/4 for 2010-2015, 3/4 for 2015-2020<br><br>2010-2020<br><br>2015-2020 |
| | Financing method:<br>Energy price + x M€ EU funding<br>(11/30 gas, 11/20 electricity, 1/12 CCS) | |
| **Policy set S3**<br>(A3, B3, C2, D3 and public support)<br><br>(alias *CS6*) | Investment electricity transmission: 142BN€<br><br>Investment gas: 57BN€<br><br>Investment CCS: 2.5BN€<br><br>**TOTAL: 201.5BN€** | 2010-2020<br><br>2010-2020<br><br>2015-2020 |
| | Financing method:<br>Energy price + y M€ EU funding to be determined<br>(11/30 gas, 11/20 electricity, 1/12 CCS) | |

[91] The available amount under the current TEN-E programme is 155M€ for the period 2007-2013.
[92] It is important to note that the E3ME model only takes into account investment taking place within the EU and therefore assumes a total investment need for gas of 57 bn€, with 49.7 bn€ corresponding to commercially viable projects.

For oil, given the limited (around 600 million euros) and only hypothetical investment needs for the considered period, it was assumed that no investments would take place.

## 3. Modelling results

Concerning the macroeconomic impacts of the different scenarios on GDP and employment, it appears that policy set S1 has a significant positive overall impact compared to BAU. The positive impact of S2 is only about half. The biggest increase in GDP and employment could be expected from policy set S3. Table 4 gives a detailed presentation of impacts for each policy set[93].

| **Policy set** | **Infrastructure investment** (in billion €, 2011-2020) | **GDP** (cumulative percentage point difference compared to BAU, 2011-2020) | **Employment** (000s, cumulative difference compared to BAU, 2011-2020) |
|---|---|---|---|
| **BAU** | 89.7 | 0 | 0 |
| **S1** | 142.2 | 0.42 | 409 |
| **S2** | 117.7 | 0.22 | 153 |
| **S3** | 201.5 | 0.9 | 774 |

**Table 4: Impacts on GDP and employment 2011-2020 (E3ME model results)**

Indeed, more investment creates the need for more employment in a first phase, notably in construction, mechanical engineering and business services. This in turn leads to higher incomes and household spending. Multiplier effects contribute in a second phase to increased employment in consumer sectors such as retail, even if these effects can be delayed in time. The model also concludes that the forecasted investment will have small positive impacts on small and medium enterprises, even if the size of certain of the bigger infrastructure projects (notably in the gas sector) might favour large companies. This confirms the positive social impacts of the different policy sets studied. Table 5 summarises the positive impacts of all policy sets on the main macroeconomic parameters for the year 2020 when compared to BAU[94]. The cumulative impact of S1 on household spending, investment, exports and imports roughly doubles the impacts of S2. The positive effect of S3 compared to S1 is even bigger, as it more than doubles investment, exports and imports.

| **Cumulative percentage point difference compared to BAU 2011-2020** | **S1** | **S2** | **S3** |
|---|---|---|---|
| **Household spending** | 0.15 | 0.07 | 0.27 |
| **Investment** | 1.30 | 0.68 | 2.93 |
| **Exports** | 0.21 | 0.10 | 0.45 |
| **Imports** | 0.21 | 0.10 | 0.48 |

[93] Increases in GDP vary significantly between Member States depending on the level of investment taking place in each of them and can be superior to 1% in 2020 for smaller countries.

[94] As the model does not take into account the different impact loops of infrastructure investment on gas and electricity prices, changes in inflation and sectoral prices are close to zero for all policy sets. No distributional impacts appear, i.e. no differentiated impact according to different income levels.

**Table 5: Impacts on other macroeconomic parameters 2020 (E3ME model results)**

It must be pointed out that due to the complexity of possible interactions between energy infrastructure investment and energy prices the analysis of their correlation at the macroeconomic level was only indicative and limited to gas. The model confirms that gas prices would decrease gradually over time compared to BAU as new interconnection capacities come on stream, which in turn would have a positive effect on GDP outweighing the additional investment cost. Concerning electricity, it was assumed that there would be no direct knock-on effects on prices (through increased and smoother supply) from new interconnection investments[95]. Given the positive price impact of the various policy options described in chapter 5, it can therefore be assumed that the model gives conservative estimates of the benefits provided by the different policy sets as compared to BAU.

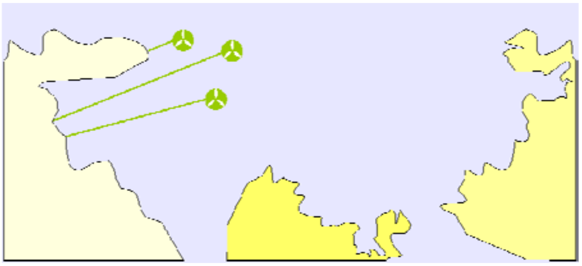
[95] Additional cross-border flows typically only occur at times of peak electricity demand and may be in both directions, making it difficult to estimate changes on the average annual electricity prices used in the model.

## ANNEX 4: DESIGN OPTIONS FOR AN INTEGRATED OFFSHORE GRID

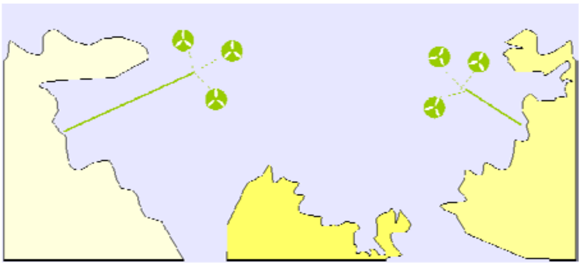
Various design options are currently studied for developing offshore grids (see graphs below). The OffshoreGrid[96] study suggests that radial grid connections in general make sense up to 50 km distance from their connection points onshore. For larger distances (in the range of 50-150 km) from shore, the concentration of wind farms is a determining factor for the benefits of clustering. Above 150 km distance, offshore grid hubs are considered as typical solutions. In countries where such hubs can easily be defined, the connection costs of offshore wind farms could be reduced by up to 34%[97]. The OffshoreGrid study has calculated that, assuming strong offshore wind development, the cost reduction for the North Sea area as a whole could be around 17% by 2030[98].

Regarding integrated "wind farm connection and interconnector" solutions, these are beneficial in terms of infrastructure investments, as there is always a cost reduction. However, the cost savings have to be compared to the increased system costs that are the result of the constraints for electricity trading, which underlines the need for coordinated approaches involving developers, regulators and TSOs to identify optimal solutions.

**Currently available designs**



Radial connection using alternating (AC) or direct current (DC) technology

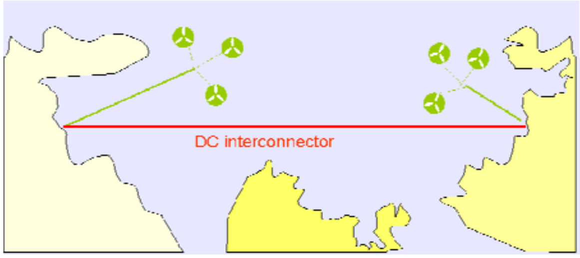


Radial AC or DC connection of clustered offshore wind power plants

[96] Financed by the Intelligent Energy Europe (IEE) programme has made a quantitative assessment of the costs and benefits of different design options in order to identify how much anticipatory investment would be needed while avoiding stranded costs. More information can be found at: www.offshoregrid.eu

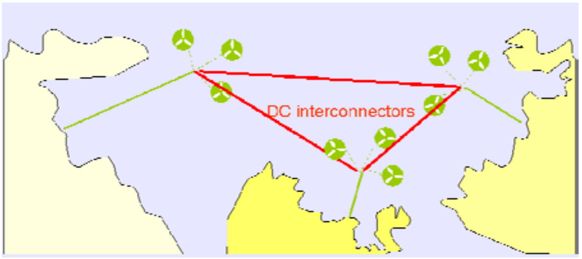
[97] Cost reduction calculated for Germany.

[98] According to the OffshoreGrid study, offshore grid infrastructure development would cost 32 billion euros until 2020 and 90 billion euros until 2030 considering radial connections. Clustering offshore wind farms at offshore hubs could reduce this investment need by 15 bn € between 2020 and 2030. Further investment need reductions could be gained by clustering wind farms before 2020 and by integrating wind farm hubs with interconnectors. According to the case study about the Great Britain / Norway / continental Europe area, an integrated solution could require 70-80% less grid investment, but would present constraints for the use of interconnectors between countries. However the net benefits are estimated to be significantly higher in this geographic area.




Radial AC or DC connection of wind park clusters with point-to-point international interconnector

**Target design**




Meshed international offshore grid based on multi-terminal scheme

Source: ENTSO-E / OffshoreGrid study

## ANNEX 5: INPUT DOCUMENTS

This impact assessment builds on the following general inputs:

- Current framework for Trans-European Energy Networks (TEN-E)[99] and its impact assessment[100]
- Green Paper "Towards a secure, sustainable and competitive European Energy Network"[101] and its public consultation[102] in the period November 2008 – March 2009.
- Implementation Report[103] on the TEN-E guidelines and TEN-E financial regulation
- European Energy Plan for Recovery[104]
- Priority Interconnection Plan 2007[105]
- Third internal energy market package[106]
- Climate and Energy package[107]
- Directive 2009/28/EC on renewables energies[108] and National Renewable Energy Action Plans[109]
- Directive 2009/31/EC on the geological storage of CO2
- Directive 2008/114/EC on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection
- Regulation concerning measures to safeguard security of gas supply and repealing Directive 2004/67/EC, impact assessment and accompanying documents[110]
- Communication on Offshore Wind Energy[111]
- Political Declaration of the North Seas Countries Offshore Grid Initiative[112]
- Declaration of the Budapest V4+ Energy Security Summit 24 February, 2010[113]

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99 Decision 1364/2006/EC and Regulation 680/2007 of the European Parliament and of the Council
100 SEC(2003) 742
101 COM(2008) 781
102 http://ec.europa.eu/energy/strategies/consultations/2009_03_31_gp_energy_en.htm
103 COM(2010)203 and SEC(2010)505
104 Regulation (EC) N°663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Union financial assistance to projects in the field of energy (OJ L 200, 31.7.2009)
105 COM(2006) 846 final/2
106 http://ec.europa.eu/energy/gas_electricity/third_legislative_package_en.htm: see notably Directives 2009/72/EC and 2009/73/EC and Regulations (EC) 713/2009, 714/2009 and 715/2009
107 OJ L140 of 5.06.2009
108 Directive 2009/28/EC OJ L140 of 5.06.2009 p. 16
109 Available at: http://ec.europa.eu/energy/renewables/transparency_platform/transparency_platform_en.htm
110 COM(2009) 363, SEC(2009) 979, SEC(2009) 977
111 COM(2008) 768
112 http://www.benelux.be/pdf/pdf_fr/act/act0170_NorthSeasCountriesOffshoreGridInitiativePoliticalDeclaration.pdf
113 http://visegradgroup.eu/main.php?folderID=859&articleID=27720&ctag=articlelist&iid=1

The impact assessment also builds on the results of the following studies:

1. *General studies*

- *EU Energy Trends to 2030: Update 2009* (Baseline 2009 and Reference scenario 2009)
- *World Energy Outlook 2009*. IEA
- "The revision of the trans-European energy network policy (TEN-E)", impact assessment study by COWI, Cambridge Econometrics and KEMA for the European Commission. October 2010
- "Energy Infrastructure Costs and Investments between 1996 and 2013 (medium-term) and further to 2023 (long-term) on the Trans-European Energy Network and its Connection to Neighbouring Regions with emphasis on investments on renewable energy sources and their integration into the Trans-European energy networks, including an Inventory of the Technical Status of the European Energy-Network for the Year 2003" (TEN-Energy-Invest), study by Centro Elettrotecnico Sperimentale Italiano, Instituto de Investigación Tecnológica, Mercados Energeticos and Ramboll for the European Commission. October 2005

2. *Studies concerning fossil fuels*

- Ten Year Network Development Plan by ENTSOG[114]
- "Methodologies for Gas Transmission Tariffs and Balancing Fees in Europe", study by KEMA. December 2009
- "Feasibility of Europe-wide CO2 infrastructures", study by Arup for the European Commission. To be published by end 2010
- "Evolution of size and cost of a trans-European CO2 pipeline network", study by the Joint Research Centre (JRC) of the European Commission. 2010
- "Technical aspects of variable use of oil pipelines coming into the EU from third countries", feasibility study by ILF and Purvin & Gertz for the European Commission (expected to be completed by autumn 2010)
- "Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios", study by EWI Institute of Energy Economics at the University of Cologne. May 2010
- "Study on natural gas storage in the EU", study by Ramboll Oil and Gas. October 2008

3. *Studies concerning the power sector*

- Ten-Year Network Development Plan, ENTSO-E. 2010[115]
- "2009 Technology Map of the European Strategic Energy Technology Plan (SET-Plan) – Part I: Technology Descriptions", Chapter 12, JRC-SETIS Work Group. 2009
- "The European Electricity Grid Initiative (EEGI): Roadmap 2010-2018 and Detailed Implementation Plan 2010-2012", ENTSO-E and EDSO. 25 May 2010
- *System Adequacy Forecast 2010-2025*, ENTSO-E. 2009
- *Power Choices*, Eurelectric. 2009

[114] http://www.entsog.eu/download/investment/ENTSOG_TYNDR_MAIN_23dec2009___.pdf
[115] https://www.entsoe.eu/fileadmin/user_upload/_library/SDC/TYNDP/TYNDP-final_document.pdf

- *Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe*, European Climate Foundation. 2010
- *Renewables 24/7: Infrastructure Needed to Save the Climate*, Greenpeace/EREC. 2009
- *Transforming Europe's Electricity Supply*, EASAC. 2009
- OffshoreGrid study[116], consortium coordinated by 3E. July 2010
- *European Wind Integration Study (EWIS)*, final report. March 2010
- *Pure Power: Wind energy targets for 2020 and 2030*[117], EWEA, December 2009
- *Oceans of Opportunity*, report on offshore wind energy[118], EWEA, September 2009
- Reports produced under SUSPLAN, REALISEGRID and IRENE 40 projects financed under FP7. Forthcoming
- "Influence of National and Company Interests on European Electricity Transmission Investments". Study by Matti Supponen, Helsinki University of Technology. Draft version dated 1 August 2010

*4. Studies concerning smart grids*

- "Impacts of Information and Communication Technologies on Energy Efficiency"[119], Bio Intelligence Service Final Report, September 2008. Supported by the European Commission DG INFSO
- "Smart 2020: Enabling the low carbon economy in the information age"[120] by The Climate Group on behalf of the Global eSustainability Initiative (GeSI)
- "The Green Grid: Energy savings and carbon emissions reductions enabled by a smart grid", Electric Power Research Institute (EPRI), Palo Alto, California, United States, June 2008 http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf
- Findings of the High-Level Advisory Group on ICT for Smart Electricity Distribution Networks: "ICT for a low carbon Economy – Smart Electricity Distribution Networks", July 2009. Supported by the European Commission, DG for Information Society and Media http://ec.europa.eu/information_society/activities/sustainable_growth/docs/sb_publications/pub_smart_edn_web.pdf
- "Electricity Storage: Making Large-Scale Adoption of Wind and Solar Energies a Reality". Cornelius Piper, Holger Rubel, Boston Consulting Group. March 2010

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