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Impact assessment

Accompanying the document

Proposal for a

Regulation of the Europen Parliament and of the Council

on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC

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BACKGROUND AND POLICY CONTEXT

This impact assessment is prepared to support the forthcoming legislative proposal on energy transmission infrastructure for the EU, which will replace the existing legal framework for Trans-European Energy Networks (TEN-E). The Commission adopted in November 2010 a "Communication on energy infrastructure priorites for 2020 and beyond", supported by an impact assessment, confirming the need to revise the existing policy and financing framework, identifying nine priority corridors/areas to be implemented by 2020 and proposing a new method to identify projects of common interest (PCIs) to implement these priorities. The Commission's approach was largely endorsed by the February 2011 European Council. In June 2011, a Commission Staff Working Paper for the Energy Council assessed in detail the investment needs and obstacles for the coming decade.

This impact assessment builds on the findings and conclusions of the above-mentioned documents and provides a more in-depth analysis concerning possible measures for permit granting, regulation and financing of energy infrastructure.
The upcoming legislative proposal will confirm the identified infrastructure priorities and establish rules for selection of projects of common interest as well as their implementation through permit granting, regulatory and whilst financing measures will be addressed in the proposal for a Connecting Europe Facility.

Out of the pool of projects of common interest, a limited number of projects will be chosen for funding under the proposed Connecting Europe Facility (CEF), which the Commission proposed in June 2011 for the next multiannual financial framework (2014-2020) and which covers energy, transport and digital infrastructure. The CEF will be dealt with under a separate regulation and impact assessment.

The general principles for financing and the criteria for eligibility of projects of common interest to CEF funding will be provided for in this proposal, while the CEF regulation will specify the selection and award criteria. It should be underlined that for the purpose of presenting and assessing the full range of possible measures with regard to infrastructure development, this impact assessment also addresses financing options, even if their translation in policy measures will take place in the CEF.

1. PROCEDURAL ISSUES AND CONSULTATION OF INTERESTED PARTIES

Identification: Lead DG: DG ENER; Agenda planning/WP reference: 2011/ENER/XXX

1.1. Organisation and timing

Between March and September 2010, a first impact assessment[1] ("the 2010 impact assessment") was prepared for the Communication "Energy infrastructure priorities for 2020 and beyond – a blueprint for an integrated European energy network"[2] ("the November 2010 Communication"), which was adopted in November 2010.

The work for this impact assessment started in November 2010. The various parts of the problem definition were discussed with the Impact Assessment Steering Group (IASG) in three meetings between February and May 2011. The policy options and impact analysis were presented to the IASG in late June 2011 and the draft final IA in early July.

Services involved in the Impact Assessment Steering Group were: AGRI, DEVCO, BEPA, BUDG, CLIMA, COMP, ECFIN, EEAS, ELARG, EMPL, ENTR, ENV, ESTAT, HOME, INFSO, JUST, JRC, MARE, MARKT, MOVE REGIO, RTD, SANCO, SJ, SG, TRADE, TAXUD

[1] SEC(2010) 1395
[2] COM(2010) 677

1.2. Consultations and expertise

1.2.1. Public consultations

Several specific consultations have fed this impact assessment. As early as November 2008 the Second Strategic Energy Review launched the Green Paper "Towards a secure, sustainable and competitive European energy network"[3] on the TEN-E revision. Among respondents from the energy industry consensus emerged on the need for a fundamental review of the TEN-E, for the EU to better align the energy network policy and the EU energy and climate policy targets, to provide for a stable regulatory framework, coordination and raising public acceptance. The respondents identified complicated administrative procedures, diverging regulatory regimes across local authorities and national borders as well as local resistance as the main barriers. The absence of a specific legal remit at EU level to mitigate these obstacles was acknowledged. 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.

Following the November 2010 Communication, a public consultation on permit granting took place between March and April 2011. The majority of the 80 respondents favours the introduction of binding time limits (60%) as well as a "one-stop-shop" approach (79%) for energy infrastructure projects.[4] To further increase transparency of the permit granting process guidelines for an earlier involvement of the public were considered helpful. This includes better communication of the economic and social benefits of projects, through promoters and authorities, as well as the early and full provision of environmental information. Regarding compensation measures, half of the respondents believed that here competency should remain with the MS and opposed a harmonization on EU level. More detailed results are presented in Annex 3.

A public consultation led by ECFIN was also carried out during the same period concerning the EU 2020 Project Bonds Initiative. More than 130 stakeholders from financial institutions, government bodies, infrastructure development, manufacturing, and research, the insurance and legal sector submitted their contributions. The initiative was considered useful by most of them. 60% considered that the bond mechanism is likely to attract private sector institutional investors to the sectors of transport, energy and ICT. A further 16% expected its success to be dependent on technical features of the mechanism (price, structure, attracted rating, etc.). Views on the project size appropriate for bond funding varied widely, but it emerged that the instrument is likely to be suitable for bigger investments with a minimum size of EUR 50 to EUR 250 million.

1.2.2. Surveys, workshops and studies

Targeted questionnaires on permit granting and financing have been sent to the main stakeholders: ENTSOs in electricity and gas, GIE, national regulators and financial institutions (notably the EIB). Results from this consultation can be found in Annex 4.

A series of four workshops took place with regulators between February and June 2011 to discuss investments needs, cost allocation and financing. A workshop was jointly organised with the Florence School of Regulation in May 2011 to discuss cost allocation issues with academics and energy experts. All relevant issues have also been presented to and discussed with other stakeholders such as industry associations or NGOs. Two workshops were also held for Member States in May and June 2011 to present and discuss options for selection of projects of common interest and permit granting measures. The working group meetings of the Baltic Energy Market Interconnection Plan (BEMIP – electricity and gas), the North Seas Countries Offshore Grid Initiative (NSCOGI – electricity) and the North-

[3] COM(2008)782 launched the public consultation between 13/11/2008 and 31/03/2009. The Commission received 91 written replies to 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. See http://ec.europa.eu/energy/strategies/consultations/2009_03_31_gp_energy_en.htm for details.

[4] Approximately 20 % did not express a clear preference.

South Interconnections High Level Group for Central Eastern Europe[5] (electricity, gas and oil) offered platforms to discuss the regional aspects of infrastructure development.

In addition, the Commission used external expertise provided through two consultant studies on permit granting and financing carried out in the period January to May 2011.

1.2.3. Other consultations

A high level conference under the Hungarian Council presidency on energy infrastructures took place on 16th and 17th May 2011, where Member States administrations, network operators, regulators and other stakeholders were given the opportunity to discuss the various proposals of the Commission. Discussions also took place at the Gas Coordination Group (March and May 2011), the Madrid (March 2011) and Florence Fora (May 2011) and at the relevant working group meetings of the Berlin Fossil Fuels Forum. Consultations with individual Member States have been ongoing on a continuous basis.

1.3. Opinion of the IAB

IAB opinion	Changes made
(1) Improve overall coherence with related policies	
The report should better describe how this initiative relates to the overriding Connecting Europe Facility and other EU initiatives such as the Project Bonds Initiative. In particular the report should ensure greater coherence and consistency with these related initiatives in terms of synergies, underlying market/regulatory failures, evaluation of results and project selection. The approach to financing modalities should be clarified.	The relation between this initiative and the CEF is now described in great detail in Section 7.3.
The problem definition should be enhanced by a better description of the wider context of the need for investment of public funds in energy infrastructure in particular by highlighting underlying problem drivers such as the market failure aspects.	The 2010 IA described in detail the overall investment needs and the project categories facing particular regulatory and market failures justifying the use of public funds. Annex 12 of this IA refines the analysis of these externalities. The IA accompanying the Regulation for the CEF discusses the need for public funds further. Section 2.2 of the 2010 IA made a detailed presentation of the current TEN-E financing framework in the context of major future investment needs and related externalities and its shortcomings (notably insufficient resources; limitation to electricity and gas infrastructure; lack of focus; rigid list of targeted projects without top-down identification of priorities; insufficient coordination with other EU funding

[5] This High Level Group was set up in early 2011 to promote the implementation of energy infrastructure projects and improve security of supply and market development in the region. It includes representatives from Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia, and Croatia as an observer.

	programmes). Section 3.3.3 of this IA explains them again. The introduction of the problem definition chapter has also been strengthened in this regard.
Greater clarity concerning the content of the proposed legal instrument should be provided and the report should better explain why this Impact Assessment focuses mainly on problems relating to permit granting, regulation and financing.	The proposed Regulation will focus on the identification of projects of common interest and measures for these projects in the fields of permit granting, regulation and financing, which is why the analysis in this IA is focused on these issues. Section 7.3 explains the content of this initiative further and establishes the link with the other proposals.
(2) Strengthen the subsidiarity analysis and option design	
The report should much better explain and justify, in terms of the principles of subsidiarity and proportionality, the need for EU level measures relating to time limits and other process and structural changes (such as 'one stop shops') to Member States' procedures for granting permits for energy infrastructure.	The description of the policy options has been complemented with an analysis of the measures with respect to the principles of proportionality and subsidiarity, and the identification of the preferred options has been more thoroughly justified in light of this analysis, stakeholder views, and the effectiveness of measures with regard to the overall objective of the proposal.
In relation to regulatory problems, the report should better explain the need for EU measures on cost allocation and tariff setting.	The business as usual scenario now has been adapted with a detailed analysis on why this is a not option and where the internal energy market rules should be complemented by new rules on cost allocation and incentives in the tariff systems and regulatory framework.
The report should discuss and underpin with adequate evidence the assumption that all identified problems, including those of an environmental nature, can be solved in an appropriate manner by a more centralised approach/procedure.	The description of the Policy Option A.2 has been extended to explain how a centralised approach would adequately address the issues at stake, particularly with regard to environmental procedures.
The presented options should be better explained and justified and more nuanced options, such as soft law, considered in greater depth.	The policy options have been explained in more detailed where necessary, particularly policy option A.1. A more nuanced suboption with respect to the establishment of time limits has been created, which is, due to constraints in text length, assessed in detail in Annex 16.
The logical flow between the identified problems on the one hand, and the proposed policy options/measures on the other, should be much more clearly established (such as the impact of changes to permitting rules on public acceptance).	A table illustrating how the proposed measures solve the identified problems has been included in Annex 17.
The report should integrate and fully address different stakeholders' views on these key points.	The report was complemented by a more detailed description of stakeholder views in the context of the proposed policy options, and explanations were provided how these have been taken into account in the selection of the policy options. A more detailed summary of the consultation on permit granting procedures has been provided in the Annex.

(3) Improve the assessment of impacts	
The report should provide a more in-depth assessment of the impacts of the options on stakeholders including Member States and citizens particularly in relation to existing rights regarding planning.	The assessment of impacts of policy options A.1 and A.2 on stakeholders with regard to existing procedures provides more details on how Member States' authorities and citizens would be affected.
The report should include a more comprehensive analysis of the legal implications of the preferred policy options concerning permit granting, which should be followed-up in the discussion of economic implications. In particular, the report should clarify the legal implications (e.g. creating a precedent, impact on other legislation) of the introduction of a Lex Specialis clause for Projects of Common Interest.	The report provides highlights in more detail that legal implications on Member States are expected to be relatively limited for the mandatory measures foreseen. However, the information needed to provide an analysis on each of the 27 EU Member States' legal frameworks is not available, and can therefore not be included in this report. The description of the legal implications in terms of the Lex Specialis with regard to the creation of a precedent and impact on the Waterframework Directive has been extended. The compatibility with the EU acquis will nevertheless remain subject to scrutiny of the Legal Service as part of the interservice consultation.
In terms of time limits the report should assess in greater depth the impact of such limits on the fulfilment of all legal requirements, including for public consultation. Furthermore the report should assess the impact of such time limits in countries where the current timeframes for awarding permits are significantly longer than the four years proposed and possible spill-overs to other infrastructure projects.	A more detailed analysis of the impacts of the time limits has been provided for policy option A.2. An illustrative overview of how the time limits and other measures foreseen accommodate existing procedures, i.a. established by environmental legislation, is provided for under policy option A.3.
Summaries of relevant findings from assessments of impacts in earlier, related IA reports should be included in the report. The report should better explain the reasons for choosing options judged to be difficult to implement (such as for example the ex ante cost allocation mechanism).	The results from stakeholder consultations have been added in the description of the regulatory options and the business as usual scenario provides for the justification of the choice of options made. In all regulatory options the views of stakeholders have been added, in particular the preferences and design options as well as likely impacts with regard to their implementation. The ex-ante cost allocation method will provide for a cost allocation principle and a framework for a joint decision by NRas concerned on the cost allocation negotiations, with the involvement of ACER in case of disagreement.
(D) Procedure and presentation	
The report should provide much greater transparency of the extent of stakeholder consultation and should better reflect the comments of all stakeholders on all major points	The views of stakeholders on the main issues of the proposal have been integrated in the text, and are particularly discussed in the context of the

throughout the main text. It should be clearer as to the extent that stakeholders and Member States have been consulted on the specific set of options assessed in this report.	policy options proposed.

2. CONTEXT

The November 2010 Communication built on an impact assessment, which covered the development of energy infrastructures for the period 2010-2020 with a view beyond to 2030. It assessed investment needs for new transmission infrastructure, evaluated the current TEN-E framework and financing possibilities and compared 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. The impact assessment analysed the design of a new policy instrument to replace the current framework and expressed preference for broad priority corridors complemented by smart and transparent criteria for identifying projects of common interest (PCIs) at EU level, thereby building on existing regional cooperation initiatives.

It also quantified the total investment need at about EUR 200 bn between 2010 and 2020 and identified **two major categories of obstacles related to permit granting and regulation and financing**. Based on a top-down estimation, it valued the projects subject to these obstacles and therefore at risk of not being delivered to approximately EUR 100 bn (also called "investment gap").

The November 2010 Communication accordingly proposed nine strategic priority corridors for the period up to 2020 and two longer-term priorities (see Annex 5), as well as a new approach to identifying, selecting and implementing projects of common European interest, including through measures in the field of permit granting, public consultation and regulation..

Both the 4 February 2011 European Council and the 28 February 2011 Energy Council endorsed the priorities proposed by the Commission and expressed support for the Commission's approach to implement these priorities, notably concerning criteria for PCI selection. The Commission presented, in a Staff Working Document[6] to the June 2011 Energy Council, a refined analysis on investment needs, investments at risk of not being delivered, and measures proposed to respond to the financing requirements and overcome the obstacles identified.

On 29 June 2011, the Commission adopted the Communication "A Budget for Europe 2020" on the next multiannual financial framework (2014-2020)[7], which proposes the creation of a Connecting Europe Facility to promote the completion of priority energy, transport and digital infrastructures with a single fund of EUR 40 billion, out of which EUR 9.1 bn are dedicated to energy.

In July 2011, the European Parliament expressed strong support for the Commission's proposed priorities, project selection method and specific implementation measures[8]. Concerning the next multiannual financial framework, it came out in favour of using the EU budget to promote the development of energy infrastructures and optimizing the use of the budget to support the Europe 2020 headline targets[9]. The Committee of the Regions also supported in July 2011 the Commission's approach and suggested the preparation of a corresponding detailed financing plan[10].

Building on the 2010 impact assessment, a complementary, more detailed impact assessment is now being presented for the legislative proposal following up on the EIP. It analyses policy options in the fields of permit granting / public consultation, regulation and financing that should apply to projects of

6 SEC(2011) 755

7 COM(2011) 500/I final and COM(2011) 500/II final (Policy Fiches)

8 European Parliament resolution of 5 July 2011 on energy infrastructure priorities for 2020 and beyond (2011/2034(INI))

9 European Parliament resolution of 8 June 2011 on Investing in the future: a new Multiannual Financial Framework (MFF) for a competitive, sustainable and inclusive Europe (2010/2211(INI))

10 CoR 7/2011 rev. 2 – ENVE-V-010

common interest selected for implementation of the defined 2020 infrastructure priorities. For each of the various obstacles identified, it assesses available, effective and cost-efficient solutions.

This impact assessment does not discuss again the identification of energy infrastructure priorities and the choice of criteria for PCI selection to implement these priorities as these issues have been analysed in the 2010 impact assessment, presented in the November 2010 Communication and further refined since with all relevant stakeholders. In line with the outcome of the 2010 impact assessment and as already specified in the November 2010 Communication, the Commission has defined simple and transparent criteria to ensure the selected projects of common interest contributes effectively to the implementation of the identified energy infrastructure priorities.

Nor does it analyse the scope of the new policy to be developed, as this was the subject of the 2010 impact assessment, which concluded that oil and carbon dioxide infrastructures should be included in addition electricity and gas infrastructures, which are already covered under the current TEN-E policy.

As a result, the infrastructure priorities form the scope of this impact assessment and the upcoming initiative. The sectors covered by the priorities are electricity transmission, storage and smart grids, gas transmission, storage and LNG/CNG, as well as transport of carbon dioxide and oil. The projects covered are all those projects with European significance, i.e. projects with a significant cross-border impact affecting at least two Member States.

The general options regarding financing of projects of common interest are discussed in this IA for the purpose of presenting and assessing the full range of possible measures with regard to infrastructure development. However, the precise problems related to EU financing, notably with regard to investment leverage and project implementation, are also discussed in the impact assessment accompanying the Regulation for the CEF. This treatment of financing questions in both impact assessments is justified, as this initiative will define the eligbility criteria for financing of infrastructure projects under the CEF, while the Regulation for the CEF will provide for award criteria and the various types of financial assistance (grants and innovative financial instruments) available for selected projects.

3. PROBLEM DEFINITION

The 2010 impact assessment explained the wider context of the need for private and public investment in energy infrastructures and highlighted in particular the **scale change in both investment volumes and investment delivery times** necessary to deliver about EUR 140 bn worth of investments in onshore and offshore electricity networks, including smart grids[11], and about EUR 70 bn in gas networks of European significance, as well as EUR 2.5 bn for the construction of CO2 transport infrastructure by 2020[12]. Investment volumes for period up to 2020 will, based on TSO forecasts, increase by 30% for gas and 70% for electricity compared to current levels[13]. Compared to the period 1989-2003, the needed annual investment in electricity transmission will even have to double[14]. This investment challenge and urgency clearly distinguishes energy infrastructures from infrastructures in other sectors, as energy networks are a precondition for reaching the 20-20-20 targets.

These estimations did not take account of maintenance, refurbishment or new investment expenses for national transmission networks without European significance or for distribution networks, nor of investments necessary for the period after 2020. The impact assessment highlighted that the identified European infrastructure priorities will represent a significant share of the investment needs. These

[11] In Europe, over EUR 5.5 bn have been invested in about 300 Smart Grid projects during the decade 2000 to 2010. Only about €300 million has come from the EU budget, mainly through Framework Programme funding. About EUR 70 million are foreseen under the Framework Programme for the period 2012/2013 on smart grid topics, while another EUR 75 million have been committed for investments in R&D for smart cities and communities. Nevertheless, the actual deployment of Smart Grids in Europe is still at an early stage.

[12] See SEC(2010)1395 for more detail on the figures and the uncertainties attached to them.

[13] Roland Berger, 2011a.

[14] SEC(2010)1395. Note also that the 2006 inquiry into the European Gas and Electricity Sectors underlined that "Amounts invested in cross-border infrastructure in Europe appear dramatically low. Only 200 million € yearly is invested in electricity grids (…)."

numbers have in the meantime been largely confirmed by national regulators and exceeded by estimates from transmission system operators[15]. The 2010 impact assessment also estimated that the full delivery of the needed infrastructure 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[16].

The security of new and existing energy infrastructures, as a key element to ensure their integrity, reliability and climate resilience are important parts of the EU's energy policy. Infrastructure security is the subject of a specific, complementary policy called the European Programme for Critical Infrastructure Protection (EPCIP). Given the possible impacts of events related to climate change such as storms, floods, heat and droughts, climate proofing of existing and even more so new infrastructures is equally important[17]. Present and future critical energy infrastructures will need to comply with existing legal instruments[18] in view of implementing the physical and operational measures to achieve a high level of security – including cyber-security – against malicious acts. Other risks, such as those related to natural hazards may also be addressed within this policy and other specific instruments in the area of safety. The measures necessary to mitigate these risks will create additional investment needs, which are part of the network operators' core duty of ensuring safe, secure and reliable transmission of energy. They are not specifically addressed in the following, as they can only be assessed by relevant actors in the spatial planning and development process for one or several projects.

3.1. Problems related to permit granting procedures and public involvement for energy infrastructure projects

Lengthy and ineffective permit granting procedures, along with public opposition, are amongst the major reasons impeding the timely implementation of energy infrastructure projects, in particular electricity overhead lines. The time from start of the process to final commissioning of a power line[19] is frequently more than ten years, and the commissioning of a project which faces substantial public opposition can even take longer (see Annex 6 for project examples). This is of particular concern in view of the massive investments in electricity transmission necessary up to 2020 and the according number of permits to be granted[20].

In the context of a survey to which 24 TSOs responded, 16 identified difficulties related to the administrative permit granting procedure and 21 identified public opposition as relevant reasons for delays in the implementation of electricity infrastructure[21]. Results of another survey amongst TSOs of 13 MS showed that public opposition was considered as the most important potential cause for delays (rating: 5.2 of 6 points), followed by complex permit granting procedures (rating: 4.5 of 6 points)[22].

15 See SEC(2011)755 for more detail.

16 The impact of developing an offshore grid would be particularly positive in this regard. A case study on Bremerhaven on the German North Sea has shown that companies in the city have attracted about EUR 250 million and created some 700 new jobs in the period 2006-2009 (Source: EWEA, "Oceans of Opportunity", September 2009).

17 Impacts of climate change and extreme weather events have shown to disrupt energy services (with significant costs to the economy). According to the IAEA, about half of the system faults in electricity grids are caused by weather effects. Adapting energy infrastructure, including transmission lines, to these effects could, according to the literature available to date, entail significant costs (see for example Vattenfall Europe (2006); Van Ierland, E.C. et al. (2007); ADAM project (2009); US National Research Council (2010)). Despite these first studies allowing an initial discussion of the issue, its specific relevance for transmission infrastructure needs to be further assessed, based on more evidence.

18 Council Directive 2008/114/EC of 8 December 2008 on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection

19 The major phases of a typical project development process in electricity are presented in Annex 6.

20 One example is the offshore grid development in the Northern Seas: According to ENTSO-E, it could lead to about 250 offshore cables needing onshore landing points between now and 2030. It should however be noted that planning and permit granting procedures are different for onshore and offshore installations, the detail and amount of environmental and socio-economic spatial data used, the number of possible planning solutions and the time it takes to involve all stakeholders being usually higher on land than at sea.

21 Acknowledging these problems, TSOs and NGOs have formed an alliance to find solutions (Renewables Grid Initiative and Smart Energy for Europe Platform), and some Member States have already introduced legislation to facilitate procedures (such as UK, IE, NL, DE).

22 Roland Berger study on permit granting procedures, 2011.

The two main drivers causing the long delays will be examined in the following sections:

1. Inefficient administrative procedures, notably with regard to the organisation of the procedures, and the conduct and competences of involved parties;
2. Opposition of affected population

3.1.1. Inefficient administrative procedures

- **Complex and fragmented process**: Although the stages of the permit granting process are generally similar in different Member States, the concrete procedures within one phase differ highly from one country to another, and often also between the different regions within one country, particularly in those countries with federal structures where planning competence is at regional level (Austria, Belgium)[23], which makes cross-border projects even more of a challenge. Furthermore, permit granting processes are also generally of extremely fragmented nature. There are typically many authorities indirectly whose opinion is required in the process. their number can reach up to 50 per project. The number of authorities directly involved, i.e. responsible to issue constitutive, legally-binding permits, is usually lower, ranging between one and more than ten (for data see Annex 7). If responsibility for the delivery of the permits is spread over several authorities, this leads to difficulties in identifying responsibilities, different interpretation of laws, inconsistencies in the handling of procedures, friction losses and duplication of work.
- **Lack of upfront planning and coordination**: It is in many Member States up to the promoter to plan the process and coordinate the different bodies and permits, with limited guidance from public administrations. However, due to lacking managerial resources and competences of promoters, coordination activities are often inefficient. Lack of appropriate upfront planning and coordination procedures has particularly severe consequences for cross-border projects, where delays on one side of the border can significantly impede progress on the other side. Such procedures are also crucial for wind offshore infrastructure projects, which often span large areas such as entire regional seas. Acknowledging the benefits of an effective upfront maritime spatial planning, the Commission is at present carrying out an impact assessment.
- **Lack of time limits:** In many Member States there are no binding time limits in place to ensure that decisions are taken in a timely fashion. In 13 MSs there are time limits for the entire procedure and/or its individual stages. However, in many MSs these are not always respected as enforcement mechanisms are not applied or do not exist. Surveys show that the permit granting process (i.e. pre-application efforts and statutory administrative procedure) has an average duration of between four and ten years (see Annex 7 for details). Adding about three years for first planning efforts and construction, this leaves an average duration of 7-13 years[24].
- **Unclear documentation standards and lack of quality**: Specific difficulties arise in the pre-application phase, when usually only limited information is available regarding the elements to be analysed and submitted with the application, and when promoters hand in application documents of poor quality. This leads to cumbersome and lengthy request-response cycles between promoters and authorities, particularly when deadlines for additional requests are missing.
- EU legislation[25] and national legislation have set high standards for **environmental protection**, which has been perceived as a major challenge by promoters during the past years. This legislation is not leading to delays per se, nor does it prevent projects from taking place, but the lack of coordinated implementation by national authorities has posed major difficulties for promoters, as the fulfilment of requirements is often time consuming and can, if not implemented adequately,

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[23] Germany adopted a law in 2011 to shift planning competence from the state to the federal level (Netzausbaubeschleunigungsgesetz – NABEG).

[24] Judicial procedures are not included in this time frame. To be noted that for complex cross-border projects the duration tends to exceed the average duration.

[25] Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment; Directive 85/337/EEC on the assessment of the effects of certain public and private projects on the environment; Directive 92/43/EEC on the conservation of natural habitats and of wild fauna and flora; Directive 2009/147/EC on the conservation of wild birds; Directive 2000/60/EC establishing a framework for the Community action in the field of water policy

lead to delays in the process. A comprehensive analysis of impacts on the environment may – depending on the available data for the specific site concerned – take one year or more as a whole vegetation period or two migration seasons have to be analysed. Particular difficulties arise if the assessment of the implications for the site or the status of a water body is negative, and if there are no alternative solutions available, as construction is in this case only allowed if the project is granted the status of overriding public interest by the national competent authority and if adequate compensation measures are taken, such that promoters face uncertainty whether a project can eventually be carried out. This issue is particularly relevant in MSs with large and scattered parts of land designated as Natura2000 habitats[26], and in border regions, which are often along natural barriers of environmental significance (e.g. Pyrenees along the ES-FR border, coastal areas).

3.1.2. Opposition of affected population

Opposition by landowners, citizens living in the vicinity of potential installations and stakeholder organisations poses the most significant impediment in the permit granting process. This is particularly true for Western MSs, where citizens seem to be more sensitive to (perceived) environmental and visual impacts, but it is increasingly the case also in new MSs. Public opposition usually leads to numerous **objections** during consultations (up to 20.000) which have to be answered by authorities and/or promoters, leading to significant additional efforts and delays in the process. Complicated and lengthy **negotiations with landowners** may also lead to delays at the stage when the developer needs to obtain the right to use the land in order to start construction. Lodging **appeals to courts** is another means of public reaction preventing the start of construction. In some countries, court appeals are possible at any time throughout the permit granting process and beyond (e.g. AU, IT), delaying the process even further. There is usually less opposition to offshore projects as citizens are not directly affected by installations. However, strong resistance of citizens living in the vicinity of landing points can prevent the timely connection of wind farms. The main reasons for public opposition, notably unclarity about the added value of a project, real or perceived impacts on the environment and landscape, health and safety concerns, and late and insufficient involvement of the public and stakeholders are presented in Annex 8.

3.2. Problems related to the regulatory framework for energy infrastructure investments

Electricity and gas transmission are regulated sectors with costs for network investment, operation and maintenance recovered through tariffs fixed by national regulation, which differs from MS to MS (see Annex 9 and 10 for statistics and relevant elements of the regulatory framework concerning EU electricity and gas markets and networks). In most MSs, cost recovery for projects is based on verified national market needs and cheapest available solutions, in order to ensure cost-efficiency and keep tariffs low for national consumers[27]. The existing framework is therefore not geared towards delivering the identified European infrastructure priorities in view of further integrating the European energy networks and meeting the European climate and energy objectives.

It should also be noted that the commercial viability and hence the "bankability", i.e. capacity to attract commercial financing, of infrastructure projects is intrinsically linked to the regulatory framework. Infrastructure operators and investors have repeatedly called for a stable and incentivising regulatory framework with adequate long-term signals, notably for cross-border investments. The way, in which investments costs and risks are treated, directly determines the return and hence influences the incentive to invest or to lend money for a project. At the same time, changing conditions in capital markets can influence regulation for such investments (see also section 3.3).

The three main shortcomings with regard to the regulatory framework, which hinder cross-border infrastructure investments, are described in the following. Examples of electricity and gas infrastructure projects subject to regulatory difficulties are given in Annex 11.

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26 E.g. 30% in the case of Slovenia.

27 Transmission tariffs account on average for only about 5-10% of household electricity prices across EU MSs.

3.2.1. Asymmetric benefits and externalities

With national energy networks becoming both more decentralised and increasingly interdependent, cross-border projects between at least two – isolated or well-interconnected – Member States or projects in one MS with significant cross-border impact multiply, which either feature an asymmetric distribution of costs and benefits among beneficiaries, or offer externalities not appropriately internalised by either market signals or the existing regulatory system. These two categories partly overlap, as many of the externalities discussed also have a cross-border, supranational dimension.

Concerning **asymmetric impacts**, a new internal electricity line can benefit the origin country by reducing its internal congestions, but also border countries by increasing transits. A gas reverse flow infrastructure on the territory of one Member State can be for the sole benefit of its neighbour, if the latter has only a single other gas supply route. Similarly, a new cross-border line (e.g. Austria-Italy in electricity, Hungary-Slovakia in gas) can de facto permit to increase transit for both the immediate neighbours and third countries, which are indirect beneficiaries.

As a result, internal as well as cross-border investments can positively impact the functioning of third country networks, without any explicit participation from the concerned network operators to the incurred investment cost[28]. This leads to a significant problem of free riding due to the asymmetry between benefit distribution and cost allocation[29]. In gas, the investment risk for new transmission networks is moreover strongly linked to the upstream and downstream commitments.

In addition, the more MSs are interconnected with each other, the more the identification of benefits can be complex and difficult to predict. Indeed, the benefits of a new electricity line on the territory of two MSs but benefiting several others indirectly can be very difficult to predict for the indirect beneficiaries, as these benefits depend on various factors such as long term price differentials, which themselves are influenced by a large set of parameters (generation mix in the exporting and importing country, support schemes for renewables, future other transmission lines). Given these uncertainties, benefits and revenues might not be quantifiable at all *ex ante*.

Today, there is no common European or region-specific framework for benefit identification and cost allocation. For more complex projects, this absence has often led to complex and lengthy decision-making negotiations between individual operators and national regulatory authorities or even made certain projects impossible to realise[30]. More specifically for gas, the lack of transparent, timely and efficient coordination across borders creates uncertainty to market participants and risks for network operators[31]. Under today's narrow framework, operators today have few incentives to develop cross-border investments when benefits go to another area.

Concerning **externalities**, they are positive or negative impacts provided by a given infrastructure investment, which are not properly reflected by existing market signals and revenue streams, i.e., in the case of regulated grids, transmission tariffs and, in electricity, congestion rents[32]. In some cases increasing the capacity or the electricity grid to the optimum level even decreases the congestion rents. While the socio-economic benefit, notably at regional or EU-wide level, of a project providing such externalities would outweigh its cost, the investment will not take place if it is based on a merely corporate based commercial viability evaluation or on optimising national interests in one MS. The

28 In its draft position paper on cost allocation, CEER calls these benefits "commercial externalities".

29 Cf. Glachant and Kalfallah, 2011

30 The Kriegers Flak project is an excellent example: It initially envisioned the development of three wind farms within German, Swedish and Danish waters, linked by a combined offshore grid connection, which would also serve as an interconnection between the three countries. The three-country solution has in the meantime been abandoned with Sweden's withdrawal, and the development of the project has been delayed because of regulatory challenges, despite EUR 150 million of EU funding received in the context of the European Energy Program for Recovery.

31 The 2006 sector inquiry had already outlined that on certain borders, long-term pre-liberalisation gas transmission capacity reservations still exist despite the ruling of the European Court of Justice that such reservations are not compatible with EC law, unless they were notified under Directive 96/92/EC.

32 In its draft position paper on cost allocation, CEER calls the externalities discussed under this category "non commercial externalities".

main categories of externalities were already discussed in the 2010 impact assessment and are further detailed in Annex 12.

3.2.2. Lack of appropriate regulatory incentives and long-term signals to meet EU priorities

Compared to the European infrastructure priorities and the EU's energy and climate policy objectives, such as the 20-20-20 targets for 2020 or the 80-95% emission reduction objective for 2050, the existing regulatory framework does not give appropriate incentives and long-term signals for the implementation of all projects necessary to meet these priorities. NRAs have so far not sufficiently taken account of the corresponding investment challenge for networks up to 2020 and beyond and their specific responsibility under the third market framework for making these investments happen.

In addition, given their cross-border nature and the broader benefits and positive externalities they provide as described in the previous section, projects of common interest in particular will often face additional technological or operational risks. Given the additional effort their development implies, operators will be reluctant to enter into the development of these projects. And without adequate return on investment, investors and banks will discard these projects compared to other "standard projects" with a lower but more certain risk-return profile. This will further endanger the timely implementation of the EU's infrastructure priorities.

Some countries have recently introduced – in addition to the existing third market legislative framework (see section 1) – additional incentive schemes in their regulatory framework to promote certain categories of investments. France (for gas) and Italy (for electricity and gas) for example give explicit incentives for congestion reduction and cross-border investments. Some NRAs have also introduced explicit incentives for innovation (UK, Italy).

Member State	Incentive Scheme
Austria	Possible ex-ante consideration of extraordinary investment costs (project specific mark-up of 0.20% for gas)
France	Gas: New investments can receive ROR add-on upon decision by the regulator
Germany	Investment budgets are approved for expansion investments by the regulator upon certain conditions. After a certain period, the investment budget is transferred into the RAB.
Italy	Investment premiums of 2%-3% for certain categories of investments
Great Britain	Specific innovation incentive schemes for low-carbon outputs (e.g. Networks Innovation Competition, Innovation Allowance, Revenue Adjustment Mechanism, Transmission Investment for Renewable Generation (TIRG))
Netherlands	Extra income for substantial investments upon decision by the regulator
Portugal	Gas: Cost of capital and amortisation are smoothed for the whole concession period (e.g. 40 years).
Spain	Investment allowances

Table 1: Existing national transmission investment incentive schemes (source: CEER)

However, such mechanisms exist only in certain Member States, remain limited with regard to the types of investment they cover and are only partly in line with the EU's infrastructure priorities.

Finally, it should be noted that investment signals and tariffs are intrinsically linked as the tariff methodology sets the main conditions for the recovery of the investment costs for regulated networks. NRAs decide on cost allocation via the tariff setting in accordance with national preferences, user and network particularities. NRAs will therefore be reluctant to provide by themselves incentives for projects of common interest, which might negatively impact their national customers for the shared and bigger overall benefit of costumers in several other Member States.

3.2.3. Lack of coordination for cross-border investment approval process

As projects of common interest will by definition affect at least two Member States, they will require approval of at least two NRAs for the corresponding investment, notably with regard to cost allocation among the two Member States involved. Coordination of procedures on both sides of the border for such approval is crucial to prevent delays or obstacles for the realisation of such projects.

This is even mort important, as national regulations differ with regard to the way, in which investments are accounted for and remunerated. For the gas sector, the 2009 KEMA study concluded that differences in commercial viability of the same project according to the different national regimes could create a serious barrier to investment: *"Investors will compare the return with similar projects in terms of risk and allocate their money accordingly"*. Concerning specifically open seasons, CEER and the Gas Regional Initiative North-West have underlined difficulties related notably to different regulatory rules applying in different MSs, the uncoordinated launch of open seasons, the lack of transparency due to invoked confidentiality by market operators and the insufficient reliability of the non-binding bidding phase[33].

Concerning electricity, experts working on regulatory issues for offshore grid development under the NSCOGI recognised that *"the regulatory regimes for offshore transmission are different and may need to become more consistent in future if coordinated development is to be achieved"*. They noted *"notable differences in grid charging regimes and procedures between the countries and these, together with the different levels of renewables support, could lead to developers seeking to locate in areas with low connection charges and high support mechanisms resulting in sub-optimum siting"*[34].

However, cooperation among NRAs and TSOs for cross-border investments and attempts at coordinating procedures have proved to be difficult and cumbersome, thereby creating delays in project approval and delivery (e.g. Dutch-German or Bulgarian-Greek cooperation in gas or Franco-Spanish cooperation in electricity).[35]

3.3. Problems related to financing of energy infrastructure projects

Energy infrastructure projects are primarily financed by the private sector. Most commonly corporate financing is used: TSOs develop projects with their own capital (balance sheet) and loans from commercial banks and international financial institutions[36]. Project finance, where the long term financing is only based upon the projected cash flows of the project rather than the balance sheets of the project sponsor, is used only rarely[37] (see Annex 13). Moreover, in order to increase their investment capacity, TSOs may seek corporate equity investments from other companies (also from outside the energy sector). Such companies offer additional capital in return for participation in profits generated by the TSO's projects.

While this system functions rather well in a predictable and stable regulatory environment, there are factors, which make the financing of infrastructures – notably those of cross-border nature targeted by this initiative – difficult[38]. Financing will be even more challenging for projects with low or no commercial viability, which are often those falling into the categories listed in section 3.2.1. Because of their high economic, social or environmental benefits, public funding would be fully justified to trigger an investment decision for such projects. Nevertheless, the existing support is insufficient both in form and available volumes. The three main factors likely to hinder investments are discussed in the following.

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33 CEER, "Monitoring Report 2010 on the compliance with the Guidelines of Good Practice of Open Season procedures (GGPOS)", Ref: E10-GMM-11-04, 7 December 2010; ERGEG Gas Regional Initiative North-West (GRI NW), "Open Season Coordination", 28 April 2009.

34 NSCOGI Working Group 2, "Report to the Steering Committee", May 2011

35 It should be noted that this impact assessment does not examine in further detail, how different national regulatory regimes by themselves impact investment decisions and to what extent harmonisation would be beneficial. This question will be addressed under the third package framework (see section **1**).

36 TSO equity in projects typically varies between 20% and 100% of the total investment depending on the project risks and scale.

37 As a general rule, if a project lies within the TSO's service area and is mainly linked to domestic transmission or distribution (gas) or uses alternating current technology in a meshed grid (electricity), TSOs will use corporate financing. Project financing, which implies setting up a special purpose company, is used for larger, specific projects such as LNG terminals, storage, merchant lines or complex joint ventures (e.g. mid-stream and some cross-border pipelines) in gas and high-voltage direct current lines or storage in electricity.

38 It should be noted that the financing challenges identified vary between Member States.

3.3.1. Limited financing capacities of TSOs

In view of the scale change in both investment volumes and investment delivery times necessary to deliver on the energy infrastructure priorities until 2020, many TSOs, especially in eastern European Member States, will reach the limits of their financing capacity. The volumes of new investments will exceed the financing possibilities offered by their balance sheet size. Both debt and equity providers have confirmed that, given the levels of available equity, TSOs will face challenges raising sufficient amounts of debt at reasonable cost, especially because of borrowing ceilings or the absence or insufficiency of investment grade ratings, as lenders are not going to accept higher debt/equity ratios. Therefore, certain TSOs could need large equity injections by private investors or public owners to be able to contract more debt for their future investment programmes. Partly or fully state-owned TSOs will depend to a large extent on their government. Given the very difficult budgetary situation of most EU MSs, it is unlikely that they will accept significant equity injections. This is especially handicapping when extensive investment plans exist and TSOs already have a high debt/equity ratio (70/30 or more), as is the case for National Grid or Tennet.

In addition, TSOs are increasingly facing **difficulties with accessing long-term debt** on favourable terms. Following the financial crisis, banks have reacted with a radical shortening of maturities, increased pricing and collateral requirements. Basel III rules[39] will require banks to keep a higher percentage of equity on their balance sheets. Long-term capital commitments for infrastructure projects will become more expensive and difficult to execute. Furthermore, lending conditions have appeared to be insufficiently adapted to project and/or corporate needs of TSOs (loan duration too short, impossibility to make a substantial bullet payment at the end of the loan, limited flexibility, no bridge financing offered between the construction phase and the operational phase)[40]. As a result, banks will favour less complex and bigger unitary transactions over more complex, innovative or riskier projects. Furthermore, access to EIB loans may become more difficult for certain TSOs[41].

These constraints will affect a TSO’s ability to deliver on its overall investment programme (including infrastructures of European and of solely national relevance). PCIs will have to compete for investment budget with national priorities. Given the increasing constraints on lending capacities, bond markets to raise larger debt volumes could play an increasingly important role in the coming years. However, issuing bonds implies that TSOs have a solid credit rating. Today, however, about 40% of TSOs in Europe (gas and electricity) are not rated[42] and therefore have no access to funding from bonds and private placements. As energy networks are regulated, an increase in tariff levels for energy consumers could be an alternative way to raise capital to finance new investments. However, there are important social and political limits to increasing tariffs (see chapter 10).

3.3.2. Difficulties for energy infrastructure investments to attract new institutional investors

Institutional investors such as pension funds, insurance companies and wealth funds are increasingly moving into infrastructure investment given its potential to match long-term assets and provide diversification. The stability provided by the regulated model corresponds to pension funds’ investment profile, characterized by relatively low rates of return – around 7%-8%[43] – and long investment horizons. These investors are also becoming increasingly ready to invest directly in infrastructure assets. This is new, as their exposure to infrastructure has traditionally been via listed

39 The Basel III global regulatory standard will come into force in 2013. It strengthens bank capital requirements and introduces new requirements on bank liquidity and bank leverage.

40 Roland Berger, 2011a.

41 Loans from the EIB are seen as the most important component of debt financing by many TSOs, especially smaller TSOs in Eastern Europe. Many TSOs have reached limits with regard to how much unsecured lending they can receive from the EIB. As a general principle, the EIB aims at not providing more than 10% of unsecured lending compared to a TSO's equity. In the EU15 TSO sector, the EIB already is often already above this ceiling. In most EU12 Member States however, the EIB does not yet agree to higher unsecured lending and requires bank or state guarantees.

42 Roland Berger, 2011a.

43 Compared to 10%-12% infrastructure funds typically offer their investors. Source: InfraNews, “How Real a Threat to Infra Funds is the Direct Investing Phenomenon?” 24 May 2011.

companies (such as utilities), or via real estate portfolios[44]. Their role as financiers for TSOs and dedicated infrastructure project companies is therefore expected to rise.

However, the arrival of such new classes of investors, which might have different expectations concerning the risks incurred compared to current regulatory practice, may require regulatory adaptations. Furthermore, there need to be investment opportunities available, i.e. equity opened to participation and/or debt products. The fact that to date only some TSOs are fully open to equity investment from third parties, given their ownership structure (see Annex 13, Figure 16 and 17), limits the inflow of capital from institutional investors and will not help to ease the investment challenge in the short to medium term.

3.3.3. Lack of adapted funding instruments and sufficient envelopes

The 2010 impact assessment already described the available financing under the existing TEN-E programme (in its Annex 2) and its shortcomings (notably limited budget, inflexibility, no risk mitigation instruments, no funding outside the EU, insufficient synergies with other EU funds). It also highlighted the positive contribution made by the European Energy Programme for Recovery[45], which has responded to some of the weaknesses identified, but was a one-off exercise.

In addition, energy infrastructrures today can benefit from the support of **Structural and Cohesion Funds**. Under the 2007-2013 budget, EUR 1.6 bn have been allocated to Member States for projects classified as TEN-E. However, available funds have seen only a slow uptake by Member States. The programming approach makes it less flexible to shift funds between projects and programmes, even if they are seen as particularly relevant from the EU energy policy perspective at a certain point of time. The funds are not centrally managed, which makes it difficult to coordinate across and between countries to ensure the regional network benefits of investments.

European energy infrastructures can also benefit from grant support under the **EU research programmes**. Such support is important from the technology development and demonstration perspective, but it does not contribute directly to the construction of industrial-scale projects.

The table below summarises the financial efforts at EU level to support the development of energy infrastructures during the current financial period (2007-2013).

		Funds allocated within financial perspective 2007-2013	**Funds spent/committed 2007-2009**			
		Electricity and gas infrastructure	**Gas infrastructure**		**Electricity infrastructure**	
			Studies	**Works**	**Studies**	**Works**
IFI	**EIB**	3 500 – 7 000	-	3 407	-	2 561
	EBRD		-	-	-	488
EU	**TEN-E**	155	22	7	23	18
	EEPR	2 268	11	1 352	2	903
	Structural Funds	1 607	24		8	
	RTD Framework Programme	150	-	-	50	-
Total IFI and EU funds		***7 680 – 11 180***	***4 823***		***4053***	

Table 2: Total funds (loans and grants) from EU institutions allocated to electricity and gas infrastructure within financial perspective 2007-2013 (* EEPR: Some infrastructure projects related to works include studies)

44 OECD, "Pension Fund Investment in Infrastructure", Working Paper on Insurance and Private Pensions, January 2009.

45 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)

The **range of financial tools** available at EU level to promote projects of common interest is for the moment effectively limited to grants. There are no specific "innovative financial instruments", which would support projects in a different manner than just by reducing the initial capital expenditure for investors. There is no possibility to provide risk capital to projects[46]. There are also no risk sharing arrangements, through which the Commission could enable financial institutions to provide sector specific lending facilities (loans on adapted terms, guarantees, facilitation of direct market (bonds) financing)[47] addressing the risks of specific projects. The existing tools do not allow for using the EU budget to accelerate project preparation by e.g. providing start-up capital.

With a growing number of complex and cross-border projects of European importance, well designed equity or debt instruments would be likely to assist them in facilitating access to equity and/or debt finance, reducing the cost of capital, adapting lending conditions to better match project cash flows and facilitating project finance structuring through standard equity and debt instruments. It is also essential to note that such form of support would come at a lower expense to the public budget (higher leverage)[48]. It should however be noted that innovative financial instruments will never be the remedy for all types of projects, especially if project financing is a prerequisite. Such instruments can only be used for projects which generate sufficient revenues to repay their debts and remunerate for financial support received – hence the need for the commercial viability of projects.

4. BASELINE SCENARIO

This chapter looks at how energy infrastructures would develop over the coming decades, should no further policy actions be taken. It builds on the chapter "Baseline scenario" of the 2010 impact assessment, which presented the methodology used for the energy infrastructure needs assessment and analysed the resulting energy trends and infrastructure needs. The findings of this chapter are not repeated here. In the following, we do however, on the basis of a detailed assessment of the current policy framework in Annex 14, analyse how much and which type of infrastructure would be delivered and which one not, if no further action was taken. This allows us to refine the analysis of investments at risk of not being delivered when needed ("investment gap" in the 2010 impact assessment).

As already highlighted in the 2010 impact assessment and as described in the previous section, the current planning, permit granting, regulatory and financing framework for energy infrastructure development will lead to significant under-delivery of infrastructures under business as usual (BAU).

Insufficient top-down prioritisation and cross-border planning will not allow focussing attention on those infrastructures, which bring the highest value added in view of reaching the 2020 energy policy targets. As a result, there is a high risk of projects of common European interest not receiving the political attention they need to be pushed trough by 2020.

Persistent delays due to **complex and lengthy permit granting procedures and low public acceptance** will further delay new infrastructure projects, notably in electricity. Under business as usual, the real duration of the statutory authorisation procedure would continue to vary between less than 2 years and 10 years depending on the Member States, with an average of about 4 years (see Annex 7). In many Member States, public resistance to new infrastructure projects would increase this duration by a significant amount of years due legal recourse procedures. The efforts associated with

[46] The Marguerite Fund, to which both the Commission and the EIB have contributed, is expected to invest also in energy projects. However, the high yield expectation is likely to exclude typical energy transmission projects.

[47] Such risk sharing instruments have already been developed for other sectors. Since more than ten years, the EU budget has been using financial instruments. Under the 2007-2013 financial framework, a new generation of financial instruments has been put in place in cooperation with the EIB, such as the Risk-Sharing Finance Facility (RSFF) under the 7th R&D Framework Programme, or the Loan Guarantee Instrument for TEN-T projects (LGTT). Although fragmented, experience until now with financial instruments has been positive in these sectors. Court of Auditors' reports have generally praised the effectiveness of these instruments, with exceptions in certain cases.

[48] Market based/innovative instruments are characterised by a higher leverage (in comparison to grants) and their potential to generate revenue for the body that provides them (unlike grants, they do not come for free)

the permit granting procedure could exceed 10% of total project costs[49], thereby also increasing the investment and the overall electricity system cost and binding resources, which could be used more efficiently for the actual investments necessary in grid infrastructure.

In line with the results of the 2005 "TEN Energy Invest" study already presented in the 2010 impact assessment, the ratio "performed investments" on "scheduled investments" in electricity could be as low as 50% for the coming decade, given the increased levels of local opposition and associated media focus on certain projects since 2005[50]. This business-as-usual scenario can be compared to the planning presented in the 2010 electricity TYNDP: Despite conservative estimates for commissioning dates, almost 30% of all projects identified foresee completion in or after 2020 or have not set a commissioning date at all. This applies in particular to 35 transboundary projects listed in the 2010 TYNDP.

Applying these results to the total investment needs in electricity of EUR 100 bn (excluding smart grid investments), it can be estimated that up to EUR 50 bn worth of projects could be subject to delays beyond 2020 and jeopardize the efforts of the EU to meet the Union's 2020 energy and climate objectives. This number has been largely confirmed by national regulators[51].

Concerning **requirements set by environmental legislation**, an analysis of the current TYNDP showed that about 20 projects may face difficulties due to conflicts with Natura2000 areas. EU environmental legislation leaves substantial flexibility to the MS competent authorities to solve the conflicting objectives between security of supply and renewables integration and the protection of the local wild life. If these conflicts are not satisfactorily solved, some of these energy infrastructure projects may be not be delivered.

Nationally focused **regulation**, lack of cost allocation solutions and difficult coordination between NRAs and TSOs would further delay the realisation of projects with cross-border impacts and increasingly asymmetric costs and benefits. This will particularly affect the implementation of the identified infrastructure priorities, which are mainly based on cross-border or even regional projects. Insufficient risk-related incentives in line with policy objectives could lead to lock-in situations with infrastructures, which in the short term contribute to energy and climate policy objectives (e.g. emission savings) but generate fewer benefits in view of longer term objectives.

Concerning *electricity interconnectors*, between 2000 and 2011, about 30 cross-border electricity projects involving EU Member States have been commissioned, out of which 25 concerned new lines (see list in Annex 15). By comparison, the 2010 TYNDP foresees a total of 76 cross-border projects, out of which 58 projects concern new lines for a total value estimated by the Commission at over EUR 31 bn. In the absence of new cost allocation rules, it is unlikely that existing regulation and new measures described above alone will allow completing the internal market, while adapting effectively to the fast rising electricity flows from variable renewable generation and the ensuing needs for balancing and storage capacities, in a context of rapidly changing national energy policies[52]. This could also endanger the reliable operation of the European electricity grid as a whole[53]. Assuming a business-as-usual development pace, only about 25 out of the 58 needed interconnectors can be expected to be online by 2020. This would leave about 30 projects or EUR 16 bn at risk.

49 This estimation is based on empirical data provided by various TSOs.

50 The ratio is even lower in the case of Germany: The 2010 DENA network study II identifies a need of grid extension of 3,500km between 2015 and 2020. A first DENA study in 2005 had estimated a need of 850km, of which less than 100km have so far been completed.

51 *"The CEER survey suggests that the volume of investments being delayed due to planning procedures, licensing and lack of public acceptance is likely to be significantly higher [than EUR 40 bn, the initial Commission estimate]."* ("European Infrastructure Package: Investment needs and financing mechanisms – Financing Task Force conclusions", reference C11-FTF-02-01, 23 March 2011).

52 Following the tsunami and ensuing nuclear accident at Fukushima (Japan) in March 2011, Germany decided in June 2011 to phase out its nuclear power generation capacities by 2022, while a referendum in Italy reverted a previous decision to develop new nuclear power plants. Several other Member States are currently reconsidering their approach to nuclear approach. This will have important consequences on the electricity mix until 2020 and beyond, with corresponding impacts on the need for additional electricity and gas transmission infrastructure.

53 Certain Central European operators in particular are warning about massive electrical power flows of insufficient control, which could lead to bulk outages of supply and, under extreme conditions, even a total blackout.

Concerning more specifically *offshore grids* in the Northern Seas, under business-as-usual with merely national regulatory frameworks and without general cost allocation rules or risk-related incentives, internationally optimised solutions – including direct connection of wind farms to international interconnectors or interconnectors between two wind farm hubs – will not be developed, while radial solutions will continue to be the preferred option of TSOs connecting new individual wind farms[54]. <u>This would affect roughly EUR 10 bn out of a total investment of EUR 30 bn foreseen up to 2020 and prevent offshore grids from starting to develop into a meshed network already by 2020</u>[55], increasing long-term costs and preventing optimal renewables and market integration at European level, also in view of developing a continental electricity highways system.

Concerning innovative investments in *electricity storage and smart grids*, it can be expected that these will progress only at slow pace under BAU, given the risks inherent to such projects, the uncertain allocation of costs and benefits and the insufficiency of existing incentives. With regard to smart grids in particular, failure to act at EU level might also lead to insufficient integration of large-scale renewables capacities and deployment of electric vehicles as well as lack of regional cross-border demand-supply optimisation. As a result, peak demand in electricity could be up to 5% higher by 2020 and up to 8% by 2030 respectively[56], with corresponding needs for investment in expensive peak load and back-up generation assets.

With regard to *gas networks*, the years 2000-2011 saw considerable development of new storages and LNG terminals with an upward trend throughout the period. Gas interconnectors, linking EU regional gas markets, however, have only developed slowly. While several new import pipelines are successfully coming online in the North and South of the EU, only 4 new gas interconnectors were built in the past decade. The EEPR support has had a significant impact in accelerating major interconnector investments in 2011 (PL-CZ, HU-CR, RO-HU). Other projects were and are being delivered on the basis of exemptions (see Annex 15).

Concerning planned future investments, the 2011 TYNDP considers higher investment needs of EUR 89 bn for the period 2011-2020 than those estimated in the 2010 impact assessment (EUR 70 bn). Projects worth about EUR 67.8 bn have not received a final investment decision (FID) yet, although they will, according to ENTSOG, contribute most to enhancing security of gas supply, creating flexible gas networks for market integration and linking isolated regions. Most of them are cross-border (EUR 58 bn). Currently planned FID projects, notably in storage, will only address additional demand under severe weather conditions (see Annex 15). <u>It can therefore be concluded that under a business-as-usual development scenario and in the light of past investments, the value of projects at risk of not being delivered could be significantly higher than the EUR 10 bn estimated in the 2010 impact assessment, in particular with regard to interconnectors.</u>

Concerning *CO2 transportation*, as already explained in the 2010 impact assessment, most of the potential EUR 2.5 bn investment needed over the period 2010-2020 will not be delivered under business-as-usual.

Business as usual would also mean the **continuation of the current TEN-E approach to financing**, with limited amounts of EU funding focussed on studies rather than works[57] and no reiteration of the

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54 The Dutch-German grid operator TenneT, which as of March 2011 had over 7 GW of offshore wind farm connection projects ongoing or planned in the German North Sea, indicated regulatory clarity among the key challenges for the feasibility and commercial viability of its projects. Operators in the United Kingdom have also indicated that the current round 3 tender process for offshore wind farm developments could lead to uncontrolled point-to-point connections onshore without overall optimisation, e.g. by developing integrated hub-and-spoke grid designs, as the latter involve too high and risky investments. This could lead to increased costs and difficulties for onshore onwards transmission on already fully used networks. NRAs have argued that hub solutions could develop in certain Member States of the NSCOGI from 2015 onwards. Results from the OffshoreGrid study show however that "teeing in", i.e. directly connecting wind farms into an interconnector, or linking two wind farm hubs in two different Member States through an interconnector makes socio-economic sense in many cases, notably if the concerned wind farms are far from shore.

55 Commission estimation, based on OffshoreGrid study results.

56 Source: IEA, April 2011

57 In the 2007-2009 period, about 65% of the allocated TEN-E funds were dedicated to studies (45M€), while 35% went to works (25M€).

European Energy Programme for Recovery. As a result, projects of European significance would continue to mainly receive EU grants for feasibility and front-end engineering and design studies. Financial support for the construction of projects would remain very limited: An expected EUR 55M of the available funds of EUR 155M would cover works expenses. In addition, EU allowed co-financing rates for works would continue to be insufficient to boost the implementation of certain projects. Indeed, as demonstrated by the EEPR experience, for projects aiming at increasing security of supply, a co-financing rate of 50% or more can be necessary to unblock the project while the current TEN-E co-financing rate is capped at 10% of the construction costs[58]. As a result, only investments with a sufficiently high direct and short-term benefit for the investor(s) would be realised, which would be insufficient to meet the challenge arising from the step change in investments[59].

Concerning the **other contributions to infrastructure financing**, it can expected that the EIB lending trends to energy grid projects observed over the last couple of years would not be maintained. While the EIB's lending volume to the energy infrastructure industry rose from EUR 2.5 bn in 2007 to EUR 6 bn in 2010 (with about EUR 3 bn for energy transmission and EUR 3 bn for energy distribution), the EIB Board of Governors has made it clear that it did not wish for extended EIB lending towards energy grid infrastructures, with lending volumes returning to pre-crisis levels, i.e. decreasing by roughly one third compared to their peak in 2010. Depending on the evolution of macroeconomic conditions and the speed of economic recovery in EU economies, this downside effect could be partly compensated by a renewed interest from commercial banks in lending to regulated, risk-free activities.

On the equity side, equity capital provision will continue to be dominated by government involvement, as a large number of European TSOs have public institutions as their majority shareholders. This will limit the potential involvement of external shareholders, leaving internal equity stemming from the TSO's own operational revenues as the main source of basic financing for future infrastructure investments. However, given the strong constraints on public finances for the coming years, it can be expected that, where external equity investments are feasible, such equity injections will be sought as an alternative. However, it might prove difficult for the TSO sector to attract sufficient amounts of such investments, given the profile of relatively low returns (less than 10%) for low risks.

In any case, even if there were sufficient debt and equity funds available under business as usual to meet the EUR 210 bn investment challenge, these market-based funds will not be sufficient to deliver the more complicated types of projects discussed above. But with a mere continuation of EU grants made available during the 2007-2013 period (excluding the EEPR) and given the likely future evolution of (repayable) loans provided by financial institutions, far less than EUR 2 bn of (non-research) grants would be available for the period after 2013 up to 2020 under business-as-usual. This amount will be severely insufficient to satisfy the funding needs expected, given the identified investments and their urgency until 2020.

As a result of these trends of the baseline scenario, the Commission estimates that a significant share of the needed investment of approximately EUR 200 bn until 2020 will not be delivered on time under the existing framework. This will make the achievement of the EU's energy and climate policy objectives in terms of renewables deployment and emission reduction by 2020 impossible, but it will also seriously hinder market integration, diversification and security of supply. Lack of interconnections will reduce opportunities for system optimisation, increase the risk of disruption and trigger additional costly back-up and balancing generation investments. Supplying energy and balancing supply and demand will become more expensive, with the corresponding effects on the competitiveness of European industries, consumers and growth.

58 Grants, however, would not provide always the right incentives to invest. Indeed, as mentioned in Chapter 2 Article 109 of the EU financial regulation, grants may not have the purpose or effect of producing a profit for the beneficiary. Consequently, while having a positive impact on network tariffs as the corresponding costs are not passed through to the final consumer through the tariffs –, grants could be perceived as a missed opportunity to make business (by excluding the possibility for TSOs to earn revenues on the corresponding asset).

59 See also conclusions from the 2009 TEN-E Implementation Report (COM(2010)203 and SEC(2010)505) and SEC(2010)1396.

5. KEY PLAYERS AND AFFECTED POPULATION

All EU citizens are affected by future energy policy as competitive, secure and sustainable energy supply is at the heart of any economic activity. Energy is a daily need in a modern world and is mostly taken for granted in Europe. More specifically, almost all 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;
- Promoters and operators of existing and new power plants as well as gas suppliers, both within the EU and in third countries, as a new policy will have an impact on the evolution of network capacity all across the EU and in its neighbour countries.
- Member State governments, administrations, specialised technical and environmental authorities (at national, regional or local level) and regulators who will be in charge of implementing and applying any new rules related to the identification of projects of common interest as well as their implementation through planning, permit granting, regulation and financing;
- Energy consumers (both citizens and businesses), as energy infrastructure investments will negatively affect final energy prices, while better interconnected, optimised and smarter grids will contribute to better balancing of energy supply and demand and increasing competition and hence influence positively the final energy price for electricity and gas;
- Landowners as well as citizens in the neighbourhood of new infrastructure, that might be affected temporarily (construction) or permanently (local environmental, safety and health impacts or visual impairment etc.), and corresponding stakeholder organisations (e.g. environmental NGOs).

6. EU RIGHT TO ACT

The EU's competence in the area of energy is enshrined in the Treaty on the Functioning of the European Union (TFEU), Article 194[60]. The EU's role needs to respect the principles of subsidiarity and proportionality.

Energy transmission infrastructure (including an interconnected off-shore grid and smart grid infrastructure) has Trans-European 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. From an economic perspective, energy network developments can best be achieved when planned with a European perspective, encompassing both EU and Member State action while respecting their respective competences. A bigger market can also better encourage development of innovative technologies for transmission and distribution of energy and financing of large-scale investments such as those foreseen among the energy infrastructure priorities.

Energy networks are therefore covered under Article 170 and 171 TFEU. Article 170 specifies: “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”.

Following the Commission's November 2010 communication on energy infrastructure priorities, the 28 February 2011 TTE Council specifically asked the Commission to present, in autumn 2011, an initiative covering the main areas of action foreseen in the "Communication on energy infrastructure priorities for 2020 and beyond" and aiming in particular at "streamlining and improving authorisation procedures, facilitating public acceptance", and at "creating the necessary framework and incentives

[60] “In the context of the establishment and functioning of the internal market and with regard for the need to preserve and improve the environment, Union policy on energy shall aim, in a spirit of solidarity between Member States, to: (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.”

for delivering infrastructure projects under the identified priorities, notably with regard to cross-border allocation of costs and benefits and their reflection in tariffs"[61].

Concerning more specifically **permit granting procedures**, Article 171-2 TFEU on trans-European networks states that "Member States shall, in liaison with the Commission, coordinate among themselves the policies pursued at national level which may have a significant impact on the achievement of the objectives referred to in Article 170". Moreover, Article 194-2 TFEU allows the EU to establish the measures necessary to promote the interconnection of energy networks. Furthermore, Article 171-2 states that "the Commission may, in close cooperation with the Member State, take any useful initiative to promote such [Member State] coordination". Hence, the formulation of broad measures to create a framework, within which Member States carry out the permit granting procedures according to their national specificities, to the aim of accelerating the permit granting process, falls in the remit of the EU. Frequent calls of industry as well as the acknowledgement of the European Council in February 2011 that "it is important to streamline and improve authorisation procedures, while respecting national competences and procedures, for the building of new infrastructure" demonstrated that most Member States have so far not been able to resolve the prevailing problems satisfactorily at national level.

7. OBJECTIVES

7.1. General objective

The general objective of this initiative is to ensure **sufficient and timely development of gas transmission, storage and LNG/CNG infrastructure, electricity transmission, storage and smart grid infrastructure as well as oil and CO2 transmission infrastructure across the EU and in its neighbourhood** in order to:

- further develop the internal energy market by interconnecting Member States and connecting island, landlocked and peripheral Member States with the central regions of the Union, so as to ensure energy provision at affordable prices to European customers,
- ensure security of supply,
- meet the EU's energy and climate goals, both in terms of binding targets up to 2020 and of longer term emission reduction.

7.2. Specific objectives

More specifically, this initiative aims at implementing, by 2020, the trans-European energy infrastructure priority corridors as defined by the February 2011 European Council conclusions. To this end, it wants to:

a) Streamline permit granting procedures to significantly reduce their duration for projects of common interest and increase public involvement and acceptance for the implementation of such projects;
b) Facilitate the regulatory treatment of projects of common interest in electricity and gas by allocating costs depending on the benefits provided and ensuring allowed returns are in line with risks incurred;
c) Ensure implementation of projects of common interest by providing necessary market-based and direct EU financial support.

7.3. Consistency with other European policies

This inititiave subscribes to the Europe 2020 strategy[62], which put energy infrastructures at 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. The priorities identified and

61 http://register.consilium.europa.eu/pdf/en/11/st06/st06207-re01.en11.pdf
62 COM(2010) 2020, 3.3.2010

the measures proposed in this initiative with regard to permit granting, regulation and financing are fully in line with these objectives.

The upcoming legislative proposal forms a logical package with the “Connecting Europe Facility” (CEF) proposed by the Commission, which will be the subject of a separate regulation. This initiative will replace the existing TEN-E policy guidelines[63]. It will set the infrastructure priorities for the coming decade and provide for specific measures concerning permit granting and regulatory issues to ensure their implementation.

With regard to financing, this initiative will only fix eligibility rules for projects of common interest to receive EU financial assistance. The award of this assistance will be governed by common rules for energy, transport and digital infrastructures in the CEF. The latter will in particular provide for the use of grants for studies and works concerning energy infrastructures. But it will also open up the possibility to use some of the EU budget allocated to energy infrastructures through different financial instruments, notably debt and equity instruments and project bonds. These mechanisms will be presented separately under the EU's new financial regulation for the next multi-annual financial framework. As a result, part of the budget which will be available for EU financial aid to energy projects would be earmarked to contribute to the cost of the bond enhancement mechanisms and other debt and equity instruments. As such, the CEF will complement the measures in the field of permit granting and regulation provided by this initiative.

The CEF, thanks to this Regulation, will be able to concentrate all EU funding for industrial-scale energy transmission infrastructure of European relevance (i.e. with significant cross-border impacts) in one instrument, including for projects that involve third countries. Available funds under the Cohesion Policy will be dedicated to infrastructure projects of national or regional importance, while funding under the Common Strategic Framework for Research and Innovation will go to pre-industrial scale projects up to the demonstration level.

Furthermore, the importance of strategic energy interconnections with our neighbours and key suppliers was underlined in the Europe 2020 Strategy, which notably highlighted the need to promote energy infrastructure projects in the Baltic, Balkan, Mediterranean and Eurasian regions. The Joint Communication of the Commission and the High Representative “A new response to a changing Neighbourhood” adopted on 25 May 2011[64] underlines the need to enhance energy cooperation, including on energy infrastructures, with neighbouring countries. The Joint Communication of the Commision and the High Representative "A Partnership for Democracy and Shared Prosperity" issued on 8 March 2011[65] calls notably for the establishment of "an EU-South Mediterranean Energy Community" and for an "EU-Mediterranean partnership in the production and management of renewables". Development of energy infrastructures of common interest is also a key objective of the Eastern Partnership Platform on Energy Security. All these developments fall within the policy objective of reinforcing the external dimension of our energy policy as called upon by the 4th February 2011 European Council Conclusions. Key orientations, including as regards infrastructures, will be developed in the Commission Communication "The EU Energy Policy: Engaging with Partners beyond Our Borders" to be adopted in September 2011.

This initiative is also a necessary pre-condition for the achievement of the two binding targets of 20% share of renewables and 20% of greenhouse gas emission reductions by 2020 and aims to be in line with the pathway set out in the Commission’s Communication on a Roadmap for moving to a competitive low-carbon economy in 2050 and the EU's long term objective of an 80-95% reduction in greenhouse gas emissions by 2050 compared to 1990 levels[66]. Through the promotion of smart grid technologies, it also facilitates demand-side efficiency and enables electrification of transport. The investments promoted by this initiative correspond to a "no regret strategy". As such, it provides an

63 Note that the Commission is preparing in parallel a revision of the guidelines for Trans-European Networks in Transport and new guidelines for Trans-European Networks for information and communication technologies.

64 COM(2011) 303, 25.5.2011

65 COM(2011) 200

66 COM(2011) 112 in combination with SEC(2011)288

important contribution to the Energy Roadmap 2050, which is currently being prepared for adoption by the Commission in late 2011. In line with the White Paper on adaptation to climate change[67], the initiative aims at ensuring that due consideration is also given to this important issue.

The objectives of this initiative are furthermore consistent with EU policies on competitiveness and innovation. Finally, this initiative is without prejudice to and does not entail any formal amendment of existing EU environmental legislation.

8. POLICY OPTIONS

In order to better analyse solutions to the problems identified above, policy options will be presented and discussed for each policy area below (see Table 3). All the options are coherent with the overarching EU objectives, strategies and priorities. A preliminary analysis will allow discarding those suboptions with the least positive impact.

Policy area A: Permit granting, stakeholder involvement and compensation		
Option A.0	Business as usual	
Option A.1	***Establishment of a regime of Common European Interest***	
Option A.2	***Organisation and limitation in time of the permit granting process***	
	Element A.2.1: Organisation of the permit granting process	
	Suboption A.2.1.a	Leading Authority without decision-making power at national level ("light one-stop shop")
	Suboption A.2.1.b	Leading Authority with decision-making power at national level ("full one-stop shop")
	Suboption A.2.1.c	Cross-border Leading Authority with European Authority of Last Resort and European permit granting procedure
	Element A.2.2: Limitation in time of the permit granting process	
	Suboption A.2.2.a	Requirement for Member States to establish time limits for each individual PCI
	Suboption A.2.2.b	Legally-binding time limits established by stakeholders in the framework of the regional initiatives
	Suboption A.2.2.c	Legally-binding time limit established by the EU legislative act
Option A.3	***Establishment of a regime of Common European Interest and organisation and limitation in time of the permit granting process***	
Policy area B: Regulation		
Option B.0	Business as usual	
Option B.1	***Cost allocation***	
	Suboption B.1.a	EU transmission tariff
	Suboption B.1.b	Ex-ante cost allocation
	Suboption B.1.c	Ex-ante cost allocation with ex-post adjustment
Option B.2	***Investment incentives***	
	Suboption B.2.a	Risk-related incentives for PCIs
	Suboption B.2.b	Penalty and enforcement action for PCIs
Option B.3	***Ex-ante cost allocation and risk-related incentives for PCIs***	
Policy area C: Financing		
Option C.0	Business as usual	
Option C.1	***Risk sharing instruments***	
Option C.2	***Risk capital instruments***	
Option C.3	***Grant support for project construction***	

[67] COM(2009) 147

Option C.4	*Combination of grants, risk sharing and risk capital instruments*

Table 3: Policy options

8.1. Permit granting, stakeholder involvement

This section presents the proposed policy options and suboptions regarding permit granting and stakeholder involvement for electricity and gas PCI. The policy options are assessed with regard to the principles of subsidiarity and proportionality as well as their effectiveness and are reflected against the opinions of stakeholders conveyed in the context of various public and stakeholder consultations. Oil and CCS projects will not be subject to the proposed measures under the proposed legislative act. Only projects in electricity and gas are facing particular urgency with a view to their contribution to the 2020 objectives in terms of renewables generation and the prevention of climate change. This rationale does not apply to oil projects, and no major concerns about lengthy permit granting procedures were raised by stakeholders. For CCS projects, there is lack of evidence for measures in the field of permit granting due to the relative novelty of the technology and the lack of concrete infrastructure projects at this stage, and the public debate on CCS is considered as not mature enough for measures to be put in place.

OPTION A.0: Business as usual - best practice and information exchange

Under this option, best-practice and information exchange to facilitate administrative permit granting procedures, including environmental assessments, and to improve transparency and public acceptance would be encouraged. The Commission would publish guidance documents and highlight best practices encountered in Member States. At European level, a communication campaign would be carried out, targeted at citizens to communicate better the costs and benefits of energy infrastructure and increase public awareness, which would complement activities at national level.

Effectiveness, subsidiarity and proportionality

This policy option is considered to be in line with the principles of subsidiarity and proportionality, as it would leave the implementation of measures to the Member States on a voluntary basis. The introduction of guidelines to enhance transparency in the process and improve communication with citizens has been clearly advocated by the majority of respondents in public and stakeholder consultations, particularly by Member States and civil society. As however the majority of respondents also favoured the introduction of a one-stop shop concept and time limits, the effectiveness of guidelines without stronger implementation measures is clearly considered as limited. Several attempts (e.g. Commission Recommendation to improve permit granting procedures for TEN-E projects[68], Commission guidance for environmental impact assessments for TEN-E projects[69]) were made to encourage Member States to shorten the duration of their permit granting processes, but the analyses conducted in the context of this impact assessment, and the various Council conclusions mentioned in Chapter 6 demonstrate that prevailing problems have not been solved sufficiently at national level, with exception of a few Member States. Therefore, the effectiveness of voluntary measures is considered as limited, which would justify the need for binding rules.

OPTION A.1: Establishment of a regime of common interest

Under this policy option, a PCI would be allocated priority status compared to other projects in the field of energy infrastructure. This would include that, with the adoption of the list of PCI by all stakeholders involved in the competent fora, the **necessity to implement a PCI would have to be**

[68] Commission Recommendation of 14 December 1998 concerning the improvement of authorisation procedures for trans-European energy networks,

[69] Commission staff working document - Accompanying document to the Communication from the Commission Trans-European Networks : Toward and integrated approach {COM(2007) 135 final}/ SEC/2007/0374

acknowledged by all parties involved in the permit granting process[70], such that it would not have to be demonstrated in dedicated tasks (such as written answers during public consultations) or procedures (such as the Déclaration d'Utilité Publique procedure in France). In essence, after a PCI has been allocated a label of "common interest", stakeholders would not have the opportunity to question the necessity of a project anymore, but would be able to focus efforts on the decision of the routing of the projects. This would be without prejudice to the need of adequate communication with the public about the costs and benefits of a given project. In Member States where certain fast-track or priority procedures have been implemented, the **highest priority level** possible would have to be applied, and authorities would have to give the **most preferential treatment** possible in terms of resources when processing PCI related files. Responding to the challenges identified with regard to environmental legislation, Article 6(4)[71] of the Habitats Directive and Article 4(7) of the Waterframework Directive would apply in that the least harmful route of a PCI could, despite negative implications for the site, be carried out for reasons of imperative public overriding interest. Prior to the allocation of this status, the conditions of the environmental legislation in place would have to be met: appropriate assessments would have been carried out, alternative solutions could not be identified, and all necessary compensatory measures would have to be taken. This rule would remove the responsible authorities' discretion to assess whether the project of imperative overriding public interest, as this would be decided by all stakeholders, including Member States, through the selection of the project in the context of the PCI identification process. A PCI could thus not be prohibited from being built due to negative impacts on the site, whilst the need to carry out appropriate assessments is fully acknowledged so as to minimise the impact on protected habitats. Complementary guidelines would have to be prepared by the Commission regarding the significance of effects and scope of assessment as well as compensatory measures.

Effectiveness, subsidiarity and proportionality

These measures are considered to be of positive effectiveness regarding the delivery of projects, as PCIs would benefit from a priority treatment in Member States. Responses in public and stakeholder consultations stated that PCI should benefit from the same political support in the Member States as national priorities. Some Member States formally or informally supported the allocation of the status of public overriding interest to PCI, although it was acknowledged that the question of compatibility with the EU acquis would have to be addressed. Other Member States as well as industry advocated at a more general level that the EU should take measures to solve conflicts between environmental and energy/climate change objectives and not leave it to the Member States' authorities, and the European Parliament called on the Commission to present a corresponding proposal.[72]NGOs reacted rather reserved on particularly this rule, but some NGOs signalled their willingness to support grid extension measures, provided that a coherent strategy with regard to the integration of renewables is followed. Under this option, the allocation of the status of "public overriding interest" would continue to be decided at national level, as the Member States are involved in the selection of projects and would have to approve the final list of PCIs.

In conclusion, these measures are considered to be effective, solving the difficulties of environmental nature where necessary, giving the Member States appropriate stake in the decisions to take, and limiting the need to change national permit granting frameworks. This option is thus considered in line with the principles of subsidiarity and proportionality.

OPTION A.2: Rules on the organisation and duration of the permit granting process

70 PCI defined as interconnection between points A and B, without prejudice to find the most suitable trajectory for this interconnection

71 According to Article 6(4) of the Habitats Directive, a project may be carried out for imperative reasons of overriding public interest in spite of a negative assessment of the implications for the site, in the absence of satisfactory alternative solutions.

72 European Parliament resolution of 5 July 2011 on energy infrastructure prirorities for 2020 and beyond (2011/2034(INI))

This option would establish concrete rules regarding the framework within which permit granting procedures are carried out. These rules would comprise two main elements: organisation of the permit granting process and duration of the permit granting process. For each of these elements, three suboptions have been identified.

Element A.2.1: Organisation of the permit granting process

<u>Suboption A.2.1.a:</u> Leading Authority without decision-making power at national level ("light one-stop shop")

MS would have to establish a single Leading Authority at national level, responsible for the overall coordination of the permit granting process of the PCIs located in their respective territory. The Leading Authority would serve as the main interface for the project promoter, and would involve and aim at achieving a common understanding between all other authorities and stakeholders concerned, with the objective that the most appropriate decision or decisions are taken within the stipulated time limit. Concrete responsibilities would include the set-up, implementation and monitoring of a permit granting schedule, scoping activities to identify the issues to be covered in the application documents, and the handling of consultation procedures, according to guidelines for early and effective public involvement as part of the legislative proposal. These would include requirements to elaborate a manual of procedures for increased transparency for all stakeholders, and to agree on a consultation concept to be elaborated by the project promoters (providing for an informal public consultation before submission of the application file). Cross-border cooperation would be ensured through regional fora, regular meetings between Leading Authorities and the elaboration of joint permit granting schedules.

<u>Suboption A.2.1.b:</u> Leading Authority with decision-making power at national level ("full one-stop shop")

MS would have to designate a single Leading Authority at national level, which would have the responsibilities as outlined under Suboption A.2.1.a. At the end of the process, the Leading Authority would have to issue one comprehensive administrative decision concerning the construction of the project.

With regard to the decision-making competence of the Leading Authority, Member States could choose between two schemes:

Under the **integrated scheme**, the comprehensive administrative decision issued by the Leading Authority would be the sole legally-binding decision resulting from the statutory permit granting procedure. Where other authorities are concerned, these could give their opinion as input to the procedure, which the Leading Authority would have to take into account when taking the decision. The integrated permit granting scheme does not correspond to the concept of "integrated environmental assessments", as different environmental authorities could give their opinion on different subject matters.

Under the **coordinated scheme**, the comprehensive administrative decision could encompass multiple individual legally-binding decisions issued by the Leading Authority and other authorities concerned. The Leading Authority would have to establish, on a case-by-case basis, a reasonable time limit within which the individual decisions have to be issued. Provided that the provisions required by EU and national legislation are respected, the Leading Authority could overrule an individual decision or take an individual decision on behalf of another authority concerned, if it is not delivered within the time limit and if the delay cannot be adequately justified, or if it is not considered appropriate by the Leading Authority.

<u>Suboption A.2.1.c:</u> Cross-border Leading Authority ("light one-stop shop") with European Authority of Last Resort and European permit granting procedure

MS would have to establish jointly a cross-border Leading Authority which would coordinate the procedures for each PCI and be responsible for the set-up, implementation and monitoring of the permit granting schedule. The national authorities involved in the process would retain their decision-making competences. In the event of an unjustified expiry of the final time limit for the final administrative decision, an Authority of Last Resort at European level would take the final decision. At this stage, the PCI legislation, and a European permit granting procedure would apply. It is the Authority of Last Resort to assess whether a delay is not justified.

Effectiveness, subsidiarity and proportionality

Consultations with stakeholders have shown that the majority of respondents favours the concept of a **one-stop shop** (79% of respondents of the public consultation on permit granting). With regard to the competences of the one-stop shop concept, the preferences of stakeholders were almost equally split between the options of a light one-stop shop versus an authority with substantial decision-making power (full one-stop shop). Industry was slightly in favour of the centralisation of decision-making power. Of the Member States responses submitted, including as reaction to the stakeholder workshops organised, seven explicitly supported the concept of the one-stop shop (with full decision-making power at national level: CZ, decision-making power at EU level: ES, LT, general support not specifying decision-making competence: CY, BE, FR, SE, no decision-making power: FI) whereas two opposed the idea (SL for fear of additional administrative burden, DK due to subsidiarity). In six Member States, such concept already exists and was explicitly advocated by most (UK, NL, IE, DE, IT, EL). Some of the latter advocated the need to introduce this concept (as well as other measures) across the EU, as in the case of cross-border projects delays in the neighbouring Member State significantly affect the domestic part of a project. It should also be noted at this point that the majority of respondents across stakeholder groups raised public opposition as a major obstacle in the permit granting process, and that remedies to involve citizens effectively and early in the process should be found.

Responding to the various concerns raised, and in light of the more detailed assessment of the suboptions in Annex 16, the introduction of a full one-stop shop with decision-making power has been identified as the most preferred suboption as it is considered to strike the best balance between effectiveness in terms of reduction of the duration of the permit granting process and the principles of proportionality and subsidiarity. This suboption takes into account the experience in Member States where the introduction of a one-stop shop approach has been successful in reducing delivery times of the permits, and where decision-making power of the one-stop shop has been crucial for the authority to effectively drive the management process forward. The issues at stake, in particular with regard to environmental challenges, would continue to be adequately addressed by this centralised approach, as under both the integrated and coordinated approach the authority in charge could continue to issue opinions/permits for its particular field of environmental competence. This has been proved in the Netherlands and in the UK. Cost-effectiveness would be given under this suboption as compliance costs would practically be the same for the designation of the Leading Authority under a light one-stop shop. However, the full one-stop shop would reduce the administrative costs spent on the handling of the procedures, as decisions could be taken more quickly.

This suboption also reflects the concerns raised with regard to issues of proportionality and subsidiarity, as decision-making remains with the Member States (no EU Authority of Last Resort), and it gives Member States the opportunity to choose one of two approaches (integrated vs coordinated scheme), therefore limiting the need for substantial reorganisation of the permit granting process. The one-stop shop is considered also as a crucial element in addressing the obstacles with regard to public resistance, as it would be responsible to issue transparency guidelines and enforce certain rules related to public involvement which would be part of the legislative act, e.g. with regard to the appropriateness of the consultation strategy of the project promoters, the enforcement of early public consultations and participation in communication activities. It is expected that an authority with responsibility for the final decision has an intrinsic interest in effectively managing the communication process, for which e.g. the UK and the Netherlands, which have a similar approach to the proposed measures, provide good examples.

Therefore, suboptions A.2.1.a, A2.1.c have been discarded at this stage.

Element A.2.2 Duration of the permit granting process

Suboption A.2.2.a: Requirement for Member States to establish time limits for each individual PCI

Under this suboption, the legislative act would require Member States to establish time limits for each individual PCI, which allows to account for the national specificities of the permit granting processes and the characteristics of individual projects. Upon establishment of the Union-wide list of PCIs, the Leading Authority would have to define an adequate time limit which it would communicate to the project promoter and other authorities concerned. In the event that a time limit is not respected, sanction mechanisms could apply in those Member States where these are foreseen by national legislation.

Suboption A.2.2.b: Legally-binding time limits for PCIs established by stakeholders in the framework of the regional initiatives

In the framework of the regional fora and in the context of the selection of PCI, MS, the national regulatory authority/ies, and possibly the Leading Authority/ies and other relevant stakeholders invited (such as NGOs and citizens' initiatives) would have to jointly agree on individual time limits for the permit granting process as well as the completion of the project of the respective PCI. The stakeholders would consequently have to sign an intergovernmental agreement, which would indicate the time limits agreed upon. This document would serve as the legal basis for possible sanction mechanisms to be initiated at EU level, if the time limit is not respected .

Suboption A.2.2.c: Legally-binding time limit for PCIs established by the EU legislative act

Under this suboption, the time between the start of the permit granting process and the final positive or negative administrative decision concerning the construction of the PCI could not exceed about **3-4 years**, which corresponds to today's EU27 average duration for the statutory procedure. The start of the permit granting process would be identified as the agreement on the notification of the project by the Leading Authority and the project promoter. This time frame would not include any judicial processes. In MS where parts of the procedures, including spatial planning, do not result in a legally-binding permit, Leading Authorities would be required to ensure that their duration is well-integrated in the overall time frame. The time between the acceptance of the submitted application documents by the Leading Authority and the final administrative decision should not exceed **1 year**.

No automatic approval or rejection of the project would be linked to the expiry of the time limit. To effectively enforce the timely delivery of the projects, sanction mechanisms could be applied at EU level if projects are subject to significant unjustified delays. The Commission would have discretionary margin to assess whether delays are unjustified and sanction mechanisms should be applied. These would include infringement procedures where MS fail to take appropriate action, complemented by reporting requirements.

Effectiveness, subsidiarity and proportionality

Regarding time limits, the majority of stakeholders who responded to the public consultation favoured their introduction (60%), particularly representatives from industry. Four Member States explicitly supported this measure (CZ, CY, (SCTL), BE, LT) whereas two opposed it (SE fears that time limits could lead to bad preparation of assessments and permits, DK due to subsidiarity). In some Member States, time limits already exist for the statutory procedure (e.g. UK, IE, NL). Particularly NGOs warned of the risks of introducing time limits, as these could jeopardise democratic principles and lower environmental standards if procedures cannot be carried out appropriately. A central issue raised was the consequence of the expiry of a deadline. Whereas it was mainly considered that time limits without appropriate implementing measures and legal consequences in case of their expiry would not have substantial effects, automatic approvals or rejections of the project were mainly considered as not viable options.

Taking into account the range of opinions conveyed, as well as one of the overall objectives of the proposal, i.e. the achievement of the 2020 targets, the prescription of time limits at EU level has been assessed as the most preferred suboption. As explained more in detail in Annex 16, the suboptions leaving more flexibility to Member States prove to be not practical in terms of their implementation, as the decision process on individual time limits would be too cumbersome, and as sanction mechanisms, which are considered as necessary for the enforcement of time limits, would only be applied in Member States where these sanctions exist (the option of automatic approval or rejection of projects has been assessed as not feasible in line with stakeholders' views). The legal grounds for the EU to act would be missing. However, taking into account concerns especially raised by Member States with regard to subsidiarity, the preferred suboption would leave flexibility to the Member States to define individual time limits, including for the various stages of the process, and to set more ambitious deadlines if considered appropriate. As the time limit envisaged is expected to accommodate well already existing time limits in some Member States, including for EIA procedures (average duration 1 year) and public consultations (average duration 4-8 weeks), no substantial change of procedural law should be necessary (for more explanations on the impacts see Chapter 9).

Therefore, suboptions A.2.2.a, A2.1.b have been discarded at this stage.

In conclusion, the preferred suboptions would set a framework within which Member States could carry out their procedures according to national specificities, and are considered as most appropriate with regard to the effectiveness of the prescribed measures as well as ambitions with respect to the principles of proportionality and subsidiarity.

OPTION A.3 Establishment of a regime of common European interest and rules on the organisation and duration of the permit granting process

This option would include both option A.1 on the establishment of a regime of European common interest and selected suboptions under A.2 on the organisation and duration of the permit granting process.

Effectiveness, subsidiarity and proportionality

See explanations above.

An overview establishing the link between the problems identified in Chapter 3 and the policy measures proposed in this Chapter is provided in Annex 17, highlighting, inter alia, the benefits of a centralised approach through the establishment of a one-stop shop, as this concept addresses most of the challenges described.

8.2. Regulation

OPTION B.0: Business as usual

Under this option, no legislative action would be taken on regulatory issues related to investment in new electricity and gas infrastructures. Third package guidelines already under preparation on capacity allocation and congestion management would be completed and applied, but no further attempts would be undertaken to establish cross-border cost allocation rules for new infrastructure and to provide specific incentives for certain types of projects.

Effectiveness, subsidiarity and proportionality

The business as usual option relies on the future full implementation and application of the third internal market rules by the Member States. As the Commission Communication of November 2010 showed, given the urgency of the 2020 objectives, the business as usual is not an option.

The public consultation of national regulatory authorities, the ENTSOs and its network operators and investors illustrated that national incentive schemes are not necessarily oriented towards the EU wide climate and energy objectives, e.g. the rate of return do not sufficiently reflect the risks faced by project promoters, and that the investment challenge is not sufficiently taken into account by national regulatory authorities.

The internal market framework is to provide for common cross-border rules on capacity allocation, tariffs and others, and is to give NRAs the competences to approve tariffs or methodologies. However, tariff structures and regulatory frameworks are likely to remain national in scope. The IEMP does not provide for a mechanism at EU level on how costs incurred in one country but for the benefit of another country should be recognized in the tariff systems. While today's tariffs are effective for national network expansion, they are not effective to advance energy infrastructure investments with a view to the implementation of the EU energy and climate objectives. There is no top-down approach on the identification of costs and benefits from an EU energy wide system perspective. There are no EU wide rules on sharing the costs of complex cross-border projects in particular where they are asymmetric (cost allocation) and deviating from 50-50 agreements between TSOs. In the light of the slow progress in past investments as outlined in the Annex Figures , without reinforced cooperation among all parties, including NRAs, networks operators, Member States and the Commission, the deployment of energy infrastructure will not be secured from the third internal market package alone.

OPTION B.1: Cost allocation

To solve the cost allocation problems outlined above, rules are necessary to properly allocate costs as a function of the benefits or positive externalities obtained and reflect this allocation accordingly in the network access tariffs paid by the beneficiaries.

Suboption B.1.a: EU transmission tariff

Under this option, a small percentage of national tariffs in each Member State would be collected to fund PCIs. Such an EU wide tariff would require substantial harmonisation of tariff structures, a separate regulatory asset base under EU regulation- This risks creating distortions by establishing a distinction between tariffs for PCIs and tariffs for other projects.

Effectiveness, subsidiarity and proportionality

While operators and academia consider an EU wide transmission tariff as an effective solution, its degree of harmonization seems to be not proportionate and is also likely to generate significant opposition from Member States and national regulators. Such harmonisation seems premature, given the limited benefit provided compared to the likely difficulty to implement it and the possible distortion effects. Depending on the design, it could be perceived as a new EU energy tax added to the final energy prices which raises not only subsidiarity concerns but ignores the differences with regard to the current level of development of grids in the various Member States, notably as a result of past investment efforts, and hence the fact that some countries will have to invest much more over the coming 10 years than others.

In the light of this, option B.1.a is therefore discarded and not assessed further**.**

Suboption B.1.b: *Ex-ante* cost allocation mechanism

Under this option, PCIs would also be funded by national tariffs. However, TSOs and NRAs of directly concerned Member States and immediate neighbours would have to agree in a coordinated approval process, *for each PCI*, on an ex-ante cost allocation solution, which would, based on a cost-benefit analysis[73], identify how benefits are allocated between these Member States and distribute investment costs for the project among national tariff schemes. To further accelerate the process, the time to agree on a common procedure and time schedule for the regulatory treatment of such cross-border PCIs would be limited and ACER be tasked to intervene in case of persistent disagreement.

NRAs as represented by CEER and within ACER taskforces contributed to the examination of the scope for cost allocation with dedicated working papers (see Annex list). NRAs underlined that the principle should be a three-step-approach: costs should be levied on the users, beneficiaries and only then on taxpayers. Within the North Sea Countries' Offshore Initiative a working group on regulatory issues concluded that cost allocation issues may arise with regard to advance capacity and the

[73] This cost-benefit analysis will serve as a harmonised tool at EU level to evaluate the global optimality of infrastructure projects, based on common input data, grid and market modelling and identify benefits overall benefits and costs, taking into account various social, economic, environmental and climate externalities, including climate proofing.

asymmetry of costs and benefits, in particular the benefits from RES support schemes. A procedure involving TSOs, NRAs and ACER was considered to suit the purpose. NRAs underlined that existing cost allocation principles (ITC mechanism, congestion rents) and regulatory practise (e.g. open seasons for gas) largely suffice. The overall conclusion was therefore that there is only a need for a general cost allocation principle along the three-step-approach and a framework for an agreement.

<u>Suboption B.1.c:</u> *Ex-ante* cost allocation mechanism with *ex-post* adjustment possibility

This option would be identical to the previous one, but each agreement would have to contain a revision clause outlining the rules for *ex post* adjustment. This would allow changes in the allocation of variable benefits and costs to be taken into account during the lifetime of a project.

NRAs suggested that some fixed cost element could be allocated ex-ante and that variable elements could be adjusted ex-post, depending on the regulatory framework and its approach on how such ex-post adjustments or risk sharing is done.

OPTION B.2: Investment incentives

<u>Suboption B.2.a:</u> Risk-related incentives for PCIs

In the workshops with NRAs it was repeatedly underlined that NRAs' independence needs to be respected to decide on the incentives and that any incentive mechanism needs to be based on the tariff system and limited only to PCIs commensurate to the risks of the project. These views were also supported by Member States. These concerns were taken on board as this option would oblige NRAs to provide PCIs, which have demonstrated higher risks than business-as-usual projects, adequate incentives for their implementation, in line with the principle of risk-adjusted return and the requirement to provide for long-term incentives via tariffs under the third package.

Eligible risks would be:

- Technology risks for new transmission technologies;
- Risks related to offshore transmission grid development;
- Specific risks related to operations and revenue streams, notably for projects with long-term benefits.

There would be no automaticity for these specific incentives, but TSOs would have to provide sufficient justification for the reasonableness of the chosen technology and proof for the extra risks claimed. This should also ensure that the incentive covers an action that can be controlled by the TSO.

Regulators would be able to choose from a set of options to trigger investments, including notably:

- Equity adders to match risks and regulated returns: The mark-up of such adders should be commensurate to the risk effectively incurred by the operator.
- Rules for anticipatory investment: These rules could involve capacity payments, regulated auctions, mandatory capacity obligations and other long-term incentives.
- Early recognition of efficiently incurred pre-operation costs not already covered under existing regulation.

Regulators would have to justify their choice. This decision-making at national level would also reflect the fact that financial incentives for TSOs differ across the EU depending on the regulatory framework, the unbundling regime, the ownership as well as shareholder structures. The appropriateness of a particular incentive scheme will therefore depend on the country, TSO and project in question.

<u>Effectiveness, subsidiarity and proportionality</u>

This option is considered to be the most effective option to provide the market participants with the incentives to make the necessary investments. In order to ensure proportionality of such incentive schemes and their compliance with state aid rules, the incentives should be only limited to the cases where PCIs are affected (limited number of EU added value projects) AND in relation to the risks incurred and set via tariff regulation. In line with the principle of subsidiarity, the NRAs are to decide on the choice of incentives on the basis of the justifications provided by operators in line with the country specific regulatory framework and network and industry structure. In line with the market-based approach and confirming NRA views, the possible use of public funding under the Connecting Europe Facility to address specific project risks, should only be envisaged once the market operators and regulatory measures have be exhausted.

Suboption B.2.b: Penalties and enforcement action for PCIs

As the alternative to incentive regulation under option B.2.a this option would build on 3rd IEMP legislation and aims giving NRAs and ACER the regulatory powers to enforce the implementation of all PCIs [74] In case of persistent non-delivery of a PCI by one or several TSOs, despite their inclusion in the TYNDP, NRAs would be enabled to impose penalties on the concerned TSOs, e.g. by reducing their regulated revenues, or ensure project implementation, e.g. through application of the measures under Article 22. In case NRAs cannot agree, ACER would ensure the mediation.Article 22 of Directive 2009/72/EC and 2009/73/EC gives NRAs the right, with regard to independent transmission operators (ITO), to ensure the implementation of all projects considered to be necessary in the short term according to the TYNDP. If an investment is not carried out by the TSO, the NRA can either force the TSO to execute it, organise a tender procedure open to any investor or oblige the TSO to accept a capital increase to finance the said investment and allow investors to participate in the capital. The 3rd IEMP strictly provides for such enforcement only for the ITO unbundling model and does not address the question of how cross-border projects would be jointly enforced.

Effectiveness, subsidiarity and proportionality

Such enforcement would be effective for the implementation of the PCIs, proportionate and fully respect the subsidiarity of the NRAs and in line with internal market rules. However, in practice NRAs may refrain from implementing such penalties, in particular the tender procedure or equity increase for other investors, due to the main characteristics of the TSO ownership structure with high state involvement.

OPTION B.3: Ex-ante cost allocation and risk-related incentives for PCIs

This option would combine option B.1.B for an *ex ante* cost allocation mechanism and option B.2.a introducing risk related incentives for projects of common interest.

8.3. Financing

OPTION C.0: Business as usual – continuation of the TEN-E with similar budget under the Connecting Europe Facility

Under this option, the financial support under the Connecting Europe Facility to energy infrastructures would be limited to mainly co-financing feasibility and project preparation (front-end engineering and design and similar) studies (continuation of the principles of the current TEN-E programme). No support would be available under the TEN-E budget for projects outside the EU, which would continue to benefit from various other EU programmes. Targeting EU support on major energy infrastructure in third countries that would contribute to improving the EU's security of supply, connecting renewables or increasing the EU's energy systems' flexibility will not be possible. Structural funds would provide very limited support to energy infrastructure projects in eligible Member States, without the possibility to channel funds to projects of the highest European relevance. The range of financial facilities available through the EIB would not evolve.

74 The Commission argues in its interpretative note on the roles of NRAs that the rule of Article 22 should not prevent NRAs from applying the mechanism to all TSOs independently from the unbundling option chosen.

OPTION C.1: Risk sharing instruments

Under this option, the EU financial support under the Connecting Europe Facility would be channelled to projects through financing instruments and facilities made available jointly with financial institutions, for example the EIB. The instruments proposed would be under the debt and equity platform principles proposed by the European Commission[75]. By accepting to share certain risks with financial institutions, the Commission would enable them to address more exhaustively the financing needs of energy projects. Projects could benefit from an improved access to bond and loan financing on favourable terms (extended duration, targeted guarantees, and increased debt financing volumes).

The risk sharing mechanism will require that the EU provides a financial institution with budgetary resources to provision for portions of statistically possible losses that operations under such instruments could generate. Normally, the risk taking would be compensated via a risk premium charged to the benefiting projects. The Union contribution would be capped at an agreed budgetary amount, thereby strictly limiting budgetary exposure and determining the size of such a facility.

The following instruments or facilities could be *inter alia* envisaged:

- project bond credit enhancement: This would be particularly suited for larger projects;
- lending enhancement (enabling a financial institution to provide e.g. loans with longer repayment period better aligned with the economic lifetime of energy assets; increased lending volumes; construction phase bridging loans): Such measures would suit projects of all sizes;
- enhancement facility (enabling a financial institution to issue guarantees[76] addressing individual project needs, including capacity utilisation guarantees[77]).

OPTION C.2: Risk capital instruments

Under this option, the EU financial support under the Connecting Europe Facility would take the form of an investment in specific projects of common interest or a special purpose vehicle developing projects with the two-fold objective of a) providing equity capital needed to attract investors and financiers, and/or b) kick-starting certain riskier projects. Support could take the form of:

- **Equity support:** The EU would provide capital to equity fund(s) (directly or via a financial institution) which actively invest in targeted projects. In order to make co-investment more attractive to third party investors and provide them with fair returns, the return target on the EU share could be subordinated vis-à-vis other investors even though the reward structure should reflect the risk taken as far as feasible. The EU participation in the funds would be in line with the main principles of the debt and equity platform proposed by the European Commission.
- **Seed capital:** In order to accelerate more complex, innovative or multi-stakeholder projects, EU financial aid would be used as seed capital to help moving a project from the "studied concept" to the project phase. Depending on the individual needs of each project, seed capital could also fund the preparation of design, legal assistance for necessary agreements, the setting-up of dedicated project development companies, or the process to obtain permits or launch procurement. In return for providing such seed capital, the EU would receive an equity share in the project, which could be bought back by other shareholders at a pre-determined future date (compulsory put option).

OPTION C.3: Grant support to project construction

Under this option, the EU would be able to support projects of common interest with the Connecting Europe Facility in the electricity (transmission, storage, smart grids) and gas sector (transmission, storage, LNG/CNG) for construction works (including procurement of construction material),

[75] European Commission, "A Budget for Europe 2020: the current system of funding, the challenges ahead, the results of stakeholders consultation and different options on the main horizontal and sectoral issues", Commission Staff Working Paper accompanying the Communication "A Budget for Europe 2020", SEC(2011) 868.

[76] Such a guarantee would be an on-budget instrument like LGTT and not imply any contingent liability for the EU budget.

[77] This would guarantee that, in case the downside scenario in capacity use materialises after project commissioning, the promoter will be able to benefit from a liquidity facility to cover the revenue shortfall and to serve its obligation towards debt providers. The mechanism would reflect the LGTT instrument already existing under TEN-T.

provided it has been demonstrated that the socio-economic cost-benefit analysis yields a positive result (also taking into account various externalities) and that the regulatory solutions proposed (notably cost allocation and risk-related incentives) alone are not sufficient to make project delivery possible. The EU could support up to 50% of the eligible cost of projects and in case of security of supply projects up to 80%. The optimal rate of support would be assessed individually for each project. This option builds on what is already now possible under the existing TEN-E scheme (with a contribution capped at 10% of a project's eligible costs) and the precedence set by the EEPR programme.

EU grants could also be made available on a repayable basis, to address the risk of advanced capacity provision. Such a grant would cover a portion of the project's eligible construction costs and be repayable if the actual use of the infrastructure exceeds the short-term expectations and therefore ensures commercial viability of the project. In exceptional cases, if there is no interest (or even opposition) by operators to develop a project clearly identified as being of common interest, an international tender could be launched where grant financing could be offered as an incentive to interested investors.In addition to construction support, the EU would continue to co-finance feasibility and preparatory studies at co-financing rates of up to 80%, as is already the case under TEN-E today. Such support would be available to both mature and less mature projects, which need further feasibility studies to assess their viability and common interest. Grants would be distributed via calls for project proposals.

OPTION C.4: Combination of grants, risk sharing and risk capital instruments

Under this option, all the above forms of EU support would be made available at EU level in the Connecting Europe Facility. The combination of market-based and direct financial support created this way would provide flexibility of providing the most cost-effective remedy to specific project risks and features at the various stages of development of the project. It should be noted that in case EU support is accompanied by national co-financing, or if Member States can decide upon the use of EU funding, the State aid rules (if applicable) must be respected, notably to ensure necessity and proportionality of the measure.

9. ANALYSIS OF IMPACTS

This chapter analyses the impacts of the various policy options and their suboptions. We will thereby insist on the most relevant impacts for each policy area. It should be noted that the evaluation of all business-as-usual options is done in chapter 4.

9.1. Permit granting, stakeholder involvement and compensation

In the following, we present an assessment of the economic, social and environmental impacts of the each of the short-listed suboptions[78].

OPTION A.1: Establishment of a regime of common European interest

In terms of **overall impact**, this option is expected to have intermediate positive effects as it would contribute to the timely delivery of significantly more projects than under BAU, provided appropriate measures on regulation and financing are in place. This result is based on the assumption that fast-track/priority procedures exist in 10 MS, but in only 5 MS this procedure is linked with a one-stop shop and/or time limit. In MS with fast-track/priority procedure alone the observed reduction in delays has been only of a few months[79]. This option would also address those PCIs not realised under BAU because of lack of recognition of their necessity or public overriding interest, as e.g. written objections during public consultations on this matter would not have to be formally answered and grounds for appeals would be more restricted.

[78] Regarding economic impacts, on costs, a distinction is made between compliance costs and administrative costs. Since the permit granting process as such is defined as an information obligation (according to IA Guidelines), all costs related to activities pursued within the permit granting process are classified as administrative costs. Compliance costs are classified as those costs related to the adaptation of national legislation and the establishment of the necessary structures by MS, as well as adaptation of processes established by promoters.

[79] Roland Berger, 2011b.

Concerning **social impacts**, citizens would be affected in that they would <u>not have the possibility to formally question the necessity of a project</u> in the context of the permit granting procedures, e.g. in the form of written objections or in litigation procedures in the form of appeals. However, this rule would be without prejudice to discussions related to the routing of a particular PCI, and potentially necessary explanations about costs and benefits of a project, such that citizens would not be deprived of their right to be adequately informed. Further, a number of citizens will be <u>affected by visual impacts of electricity overhead lines on their property and in their vicinity</u>. Regarding safety and health issues, thresholds for electro-magnetic fields implemented by MS have to be respected when constructing electricity overhead lines, which are often lower than the recommendations given by the EU[80].

The **impacts on the environment** <u>are not expected to increase greatly under the new regime</u> vis-à-vis the current one, given the assumption of earlier completion of projects rather than significantly increasing the overall volume. Impacts affect <u>the local flora and fauna</u>[81]. Some short-term disturbances to animals and destruction of plants and habitats may occur during construction work, and some permanent displacements of animals and destruction of plants might take place due to the existence of underground cables, gas pipelines and electricity pylons. Further, overhead electricity lines might make it necessary to keep open vegetation in corridors in wooden areas and cause habitat fragmentation to animal and plant species and disturbances to birds. These impacts will vary depending on the project, but are considered to be rather limited for electricity line projects, as, due to the size of electricity pylons only small areas are affected, and underground impacts of gas pipelines and cables are expected to be less important due to the limited existence of wildlife there. As regards specifically the impact of electricity lines on birds, there is only a minor risk of electric shocks of birds with high voltage lines[82]. However, collision risks for large bodied soaring bird species may be serious if no adequate mitigation measures are taken. A micro-level assessment of impacts on the environment cannot be carried out at this stage, as this is subject to the analysis to be carried out by project promoters under the relevant legislation in place.

As regards particularly the measure related to the allocation of the status of public overriding interest to PCIs in the context of the Habitats Directive, the impact on the local flora and fauna is expected to be relevant for only a subset of the 20 projects identified as possibly in conflict with Natura2000 areas, which are, however, crucial for the achievement of energy and climate policy objectives[83]. As explained in Chapter 4, a preliminary analysis has been conducted to identify projects which may need to make use of the Lex Specialis, by matching, at an aggregate level, the possible route of the cross-border projects taken up in the existing TYNDP with Natura2000 areas. Yet, the final list of PCIs is subject to a selection process, and the identification of possible conflicts with protected areas is subject to the environmental assessments to be carried out by project promoters. This means that the exact route of the PCI and the concrete alignment will be determined in the process comparing all alternatives and not before that. Therefore, a more detailed assessment of the impacts is not possible at this stage. With regard to legislation in the field of water policy, problems related to water issues have, in contrast to problems related to Natura2000 areas, not been stated as a major concern by stakeholders. Only limited use, if at all, is expected to be made of the Lex Specialis in the framework of the Waterframework Directive, such that the impacts on inland surface, transitional, coastal and groundwater are expected to be minor. However, if necessary, the legislative act would allow for the prioritisation of energy projects consistent with provisions on the Habitats legislation. A more detailed analysis cannot be provided at this stage for the same reasons valid for the assessments on flora and fauna, and since a comparison of aggregate data with the routing of relevant projects is not possible, as information on neither data nor the characteristics of the project (whether surface, underground etc.) is sufficiently available at this stage. Overall, due to the requirement to carry out appropriate assessments

80 Council Recommendation 1999/519/EC on the limitation of exposure of the general public to electromagnetic fields (0 Hz to 300 GHz).

81 Short-term disturbances to animals and destruction of plants and habitats during construction work, permanent displacements of animals and destruction of plants due to the existence of underground cables, gas pipelines and electricity pylons.

82 Haas, Dr. Dieter and Bernd Schürenberg, "Stromtod von Vögeln", p.16, January 2008.

83 Immediate and strong impacts would only be expected if PCIs were completely exempted from the obligation to carry out appropriate assessments. However, this is not considered as viable with regard to biodiversity objectives.

as established by environmental legislation, the obligation to choose the least harmful route, and the necessity to undertake adequate mitigation and compensation measures, it is expected that the above described limited negative impacts will be offset.

Where the urgent need of integrating renewables and preventing climate change make the balancing of environmental and climate change objectives necessary, this rule could set a precedent for non-PCI projects in the field of energy, in that Member States could choose to extend the scope of this provision. However, it is expected that no precedent is created for other sectors, as the energy sector faces particular urgency regarding the delivery of projects due to the 2020 objectives.

Strong positive effects with regard to climate policy objectives are expected – if the EU cannot meet its energy and climate objectives climate risks will further grow and deteriorate the environment. The construction of electricity lines enables the large-scale deployment of renewable energies, with its positive impacts in terms of reduction of CO2 emissions. Whilst it is difficult to quantify impacts and compare effects on the local environment with the contribution of energy infrastructure to the prevention of climate change, it is expected that the overall balance of impacts is positive. In addition, the fight of climate change has positive effects on the preservation of biodiversity, as global warming could extinct certain species not adapted to higher temperatures[84].

Regarding **economic impacts,** the assurance that the necessity of a project is acknowledged and that projects can be built despite potential conflicts with Natura2000 areas will increase investors' certainty and positively contribute to the projects' commercial viability. Minor impacts in terms of compliance costs are expected: In MSs where the necessity of a project or the application of any other priority scheme is established by law, resources would be needed on the authorities' side to adapt national legislation, such that PCIs are accounted for in these.

Regarding administrative costs, the reduction of resources needed for processing a given number of projects is estimated at about 3% on the promoters' side, and 12% on the authorities' side. As described in Annex 16, this results from the fact that less resources would be needed to handle objections related to the necessity of the project, and that existing fast-track procedures would be applied. Additional savings to be expected in the context of litigation procedures are not taken into account here, as these are not subject to the legislative act[85].

In terms of the **legal feasibility** of this option, some adaptation of national legislation would be necessary in those countries where priority or fast-track regimes and/or the acknowledgement of the necessity of a project are established by a legislative act (e.g. UK). In countries where the necessity of a project is established by a procedure on a case-by case basis (e.g. France), this procedure could serve to define the concrete routing of a PCI. In other countries, the EU legislative act would serve as legal basis. It is expected that the measure related to the Habitats and Waterframework Directives would not require an explicit amendment, but would rather constitute a Lex Specialis, which is not in contradiction with the rules established. However, the analysis of this measure has not been entirely concluded to date and will be subject to a more detailed legal analysis as part of the elaboration of the legislative act.

OPTION A.2: Rules on the organisation and duration of the permit granting process (suboptions A.2.1b "full one-stop shop" and A.2.2.c "legally-binding time limit established by legislative act")

The **overall impact** of this option is expected to be strong and positive, as it would allow a large majority of projects needed by 2020 to be delivered on time, provided appropriate measures on regulation and financing are in place. The number of projects realised on time would be higher than with option A.1, under which fast-tracking with one-stop shop and time limits would only be possible in those Member States where it is already established. Analysis has shown that the existence of a one-stop shop is positively correlated with the duration of the permit granting procedure[86] (see Annex 7). In countries where one-stop shops exist (EL, IE, IT, NL, UK), the entire permit granting process

[84] Some species adapted to higher temperatures could however be positively affected.
[85] See Annex 17 for more details on methodology and assumptions.
[86] Note that one-stop shops identified have different degrees of decision-making power.

including pre-application efforts has an average duration of 4-5 years[87]. Legally-binding time limits will reinforce the positive impact of the one-stop shop measure on durations, as they are crucial to incentivise promoters and authorities to complete the permit granting process in a timely fashion, and for sanction mechanisms to be taken at EU level if considered appropriate and justified. Regarding the two-step approach (2-3 years for pre-application efforts and 1 year for the statutory permitting procedure, experience in MS where one-stop shop concepts and time limits have been introduced has proven that this two-step approach is effective and feasible, and leaves ample time for promoters to complete assessments (for more details on the effectiveness of the one-stop shop and time limits, see Annex 16), which was also confirmed by a study carried out in the context of this Impact Assessment.[88]

In Member States where the current time frames are significantly longer than the four years proposed, it is expected that the measures foreseen under this policy option reduce the duration of the process, whilst legal requirements, particularly with regard to public consultations and environmental assessments, can continue to be respected. In essence, the time limit would incentivise authorities as well as project promoters to work against a given time line, which generally has positive effects on the delivery of projects.

The time limit can however not be considered as a stand-alone measure, but has to be assessed in combination with the full one-stop shop, which would hold the final responsibility of implementing a permit granting schedule, controlling the process and identifying intermediary milestones, and whose introduction would reduce the friction losses and delays occurring when a number of parties handles a project in an uncoordinated manner. Complementary measures regarding mandatory scoping activities (the identification of issues to be covered in the application) would further make it possible for promoters to have certainty regarding the issues to be assessed, including environmental impacts.

However, the time limit would force the relevant parties to limit the content of assessments to the necessary issues, based on realistic scenarios, without demanding assessments for improbable consequences as it is in some cases reported practice. Public consultations will under the proposed measures continue to be held according to national rules, but where opposition due to NIMBY phenomena delays projects outside the framework of formal public consultations and where responsible authorities avoid decisions due to e.g. upcoming elections, the time limits, together with the full one-stop shop and appropriate sanctions, would accelerate decision-taking. It should be noted that decisions can be either positive or negative. Concerns that, under the coordinated approach, local authorities defer their decision to the national level have proven to be not valid, as the local authorities try to keep the decisions at their level to retain the maximum influence possible, as has been shown in the Netherlands.

The measures foreseen would only be binding for electricity and gas projects, but could however have positive spill-over effects, as Member States could choose to apply these to other infrastructure projects. Particularly in the field of renewables energy integration, this could have even more positive implications for the delivery of the 2020 objectives.

However, it is expected that not all projects would be completed on time despite these measures. Some PCIs would not get the fast-track/priority treatment, while others would be stopped in cases where a public authority does not grant the status of overriding interest when it comes to the crossing of Natura2000 areas, or if long debates on necessity prevent the project before the start of the statutory process.

Concerning **social and governance impacts**, this option would significantly improve conditions for citizens to participate in the decision-making process regarding the routing of a PCI. The time limit introduced by the legislative act to be binding on the project promoters would not jeopardise

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[87] In the Netherlands for instance, the one-stop shop as main feature of the new permit granting regime has resulted in the reduction of the entire process from an average of 10-15 years to 6 years (including realisation of about 2 years), whereas in some other countries where only loose or no coordination mechanisms exist, the completion of procedures can take significantly longer. Acknowledging the difficulties related to a fragmented permit granting process, Germany has just adopted a law (NABEG) to shift permit granting competence from state to federal level.

[88] Roland Berger study on permitting (2011).

democratic principles and touch upon existing rights, as statutory public consultations have an average duration of between 4 and 8 weeks and project promoters will have to respect them.. These time frames can be well-integrated in the time frames foreseen under the legislative act, as has been proved in several Member States. The measures foreseen would rather be beneficial to citizens, as the Leading Authority and/or promoters would be responsible to give clear indications about intervention possibilities for citizens (e.g. manual of procedure, project website) and elaborate consultation concepts at the start of the permit granting process. Further, an early (informal) public consultation would be required also in Member States where such consultations are not already carried out, thereby enabling citizens to raise their concerns at an early stage of the process. Hence, the implementation of time limits would not prevent citizens from actively participating in the procedure, but instead, by "frontloading" the process through early information and consultation, give them more opportunity to participate when decisions about alternative routes can still be influenced.

Some authorities might face effects on their autonomy in areas for which they are competent[89]. This would be the case if a Member State chooses to implement an integrated approach (Alternative 1), as all authorities other than the Leading Authority would lose their responsibility of issuing a legally-binding permit. Yet, they would still give their opinion to the Leading Authority, which would have to take it into account to prevent litigation procedures.

But Member States could also implement a coordinated approach (Alternative 2), where authorities may retain their responsibilities and continue to issue their permits. In this case, only Leading Authorities at federal level would be affected in their autonomy, as well as authorities which are responsible to issue consolidated permits for a particular area of expertise. The Leading Authority would take over coordination tasks, but the responsible authorities could continue to issue technical permits. Other authorities involved in the procedure would only be affected if the Leading Authority had to step in because of unjustified time overruns. Evidence is only available to a limited extent, as, according to the analysis carried out, this approach has only been implemented in the Netherlands.

Table 4 gives an overview of the type of authorities typically involved in the permit granting process across Member States and the consequences of the new regime (under both alternatives) in terms of decision-making power for each of them.

Type of authority / Alternatives	**Alternative 1: integrated approach** (only leading authority issues permit)	**Alternative 2: coordinated approach** (individual authorities issue respective permits)
Leading Authority at national level - full national one-stop shop (e.g. NL, UK, IE, IT, EL, DE (taking into account new legislation (NABEG))	No impact	No impact
Leading Authorities at federal state level (AU, partially BE)	No competence under new regime	No competence under new regime
Authorities responsible to issue a consolidated permit for a particular area of expertise (**Responsible Authorities**) (e.g. FR, HU)	Input in form of opinion to the permit granting procedure, no consolidated permit	Input in form of technical permit possible, main coordination and consolidation tasks to be taken over by Leading Authority
Other technical, environmental, regional and local authorities giving input to the permit granting process or issuing individual permits (**Other**	Input in form of opinion to the permit granting procedure, no individual permit	No impact

89 The particular authorities involved vary across Member States. They generally include national ministries responsible for energy and for environment, regional technical and environmental authorities, municipalities and other local authorities, etc.

authorities involved) (all MS)		

Table 4: Consequences of new permit granting regime on authorities involved

Environmental impacts are not expected to considerably differ from the impacts described under policy option A.1. They would be slightly stronger from the perspective of impacts on local flora and fauna as well as on climate change, as more projects are expected to be completed under this policy option.

Concerns that environmental impact assessments are not adequately carried out and reviewed due to the introduction of time limits are considered as not valid. The time frame envisaged would well accommodate the time needed for the EIA procedure (a study estimated the average time needed from notification to decision as 1 year)[90] and further assessments required according to other environmental legislative acts, as proved in Member States where streamlined procedures have been introduced. Regardless whether an integrated or coordinated approach is chosen by the respective Member State, it would not be compulsory to harmonise environmental assessment procedures. Autonomous assessments may continue to be carried out, as individual permits or opinions could continue to be given by the authorities responsible for their particular field of competence.

With regard to **economic impacts**, compliance costs would be higher than under option A.1. MSs would have to adapt national legislation to accommodate (re)assignment of coordination and decision-making powers, and would have to set up the necessary administrative structures and to transfer staff from authorities previously responsible and/or recruit additional staff. As only a limited number of PCIs will be subject to the measures envisaged (about five per Member State), the number of additional staff needed is not expected to be significantly high. Under the coordinated approach, it is expected that one person can process two projects, such that about 2.5 FTE would be needed. Thus, compliance costs are considered to be limited under the assumption that Member States choose the coordinated approach under this policy option, where authorities retain most of their responsibilities, and that an existing authority will be designated as Leading Authority, such that no entirely new structures will have to be created.[91] Promoters will have to familiarise themselves with the new regime.

Positive impacts on administrative costs are also expected to be more significant under this policy option. As shown in Annex 18, it is estimated that under the new regime, 25% of administrative costs can be saved per project on the promoters' side, with a reduction from EUR 114.5 million in the time frame 2014-2020 to EUR 85.9 m, assuming a total of 150 electricity projects to be authorised. On the authorities' side, 34% of administrative costs could be saved, with a reduction from EUR 22.6 m under BAU to EUR 15 m. This accumulates to **total savings of 26% of administrative costs** from EUR 137.1 m to EUR 100 m for both authorities and promoters in the period 2014-2020.[92]

It should at this point be noted that the reduction of administrative costs and the alleviation of administrative burden on promoters is not the main objective of the legislative act subject to this impact assessment as it would constitute only a minor part of the overall construction costs. This proposal rather aims at ensuring the realisation of the infrastructure investments on time.

In terms of **legal feasibility,** the need to adapt national legislation depends on the one-stop shop approach selected by a Member State, being more extensive for the integrative approach than for the coordinated approach. Feasibility of this suboption has been proved in those Member States where full one-stops with different forms of decision-making power have been established. Respect of

90 GHK, "Collection of information and data to support the IA study of the review of the EIA Directive", 2009. Note that notification in this context means application for screening.

91 Austria with planning and permit granting competence at federal state level would be, according to the analysis conducted, an exception, such that a new authority would be responsible at national level.

92 Results are based on the relatively conservative assumption that two authorities are responsible for the permit granting process under BAU, which are coordinating other technical, regional and/or local authorities and stakeholders involved. However, this is only one type of permit granting regime existing in the different MS. Impacts would be greater if there were, as it is in many MS the case, more responsible authorities, or if the responsible authority was not or only partially coordinating other authorities and stakeholders involved. In the latter case, a shift of administrative costs (not more than 2%) from promoter to authority is expected.

requirements in place is inherent to the permit granting process as authorities have to ensure that permits can withstand administrative or judicial reviews. Regarding time limits, adaptation of national legislation is expected to be necessary in Member States where national rules foresee different time limits, but these adaptations are expected to be of limited extent. However, according to the analysis carried out, the time limits established by some of the Member States for the entire statutory permit granting procedure, which are generally shorter than one year, or for individual steps of the process can be well accommodated within the time limit, such that there would be no need for adaptation of national procedural law. Member States would not be prevented from setting more ambitious deadlines than the ones foreseen by the legislative act. The time limit established by the EU would only define the point in time when EU sanction mechanisms apply, but leave Member States the flexibility to set and enforce time limits according to their national practice (for more explanations see Annex 16). In conclusion and as stated in Chapter 8, it is considered that the measures foreseen are in line with the principle of proportionality, as the need to adapt national legislation is limited compared to the positive impacts described above, and as this policy option would set conditions for a general permit granting framework, within which Member States will be able to carry out their procedures according to national specificities.

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OPTION A.3 Establishment of a regime of common European interest and rules on the organisation and duration of the permit granting process

The **overall impact** of this policy option, which combines the impacts of options A.1 and A.2, is considered to be the <u>most positive of all options,</u> as it would lead to the on-time completion of almost all the needed projects by 2020, provided appropriate measures on regulation and financing are in place. It would make compulsory in all Member States those measures, which are crucial for the facilitation and acceleration of permit granting procedures, not only those where fast-track regimes and one-stop shop approaches have been implemented, and prevent projects from being stopped due to issues related to the necessity or public overriding interest of the project. **Environmental impacts**, **social impacts** on employment and **economic impacts** on GDP are expected to be stronger under this policy option as all projects would be completed. Regarding compliance and administrative costs, effects would accumulate, with a reduction of administrative costs of 28% on the promoters' side, and 46% at the authorities' side, equalling a reduction of 31% in total from EUR 137.1 m under BAU to EUR 95 m.

Table 5 illustrates the compatibility of the main measures envisaged with a typical permit granting process, particularly with regard to EU environmental requirements. The only deviation from existing practice would consist in the automatic allocation of the status of "public overriding interest" to the least harmful route of a PCI, in that the environmental authorities' discretion to allocate such status would be removed.

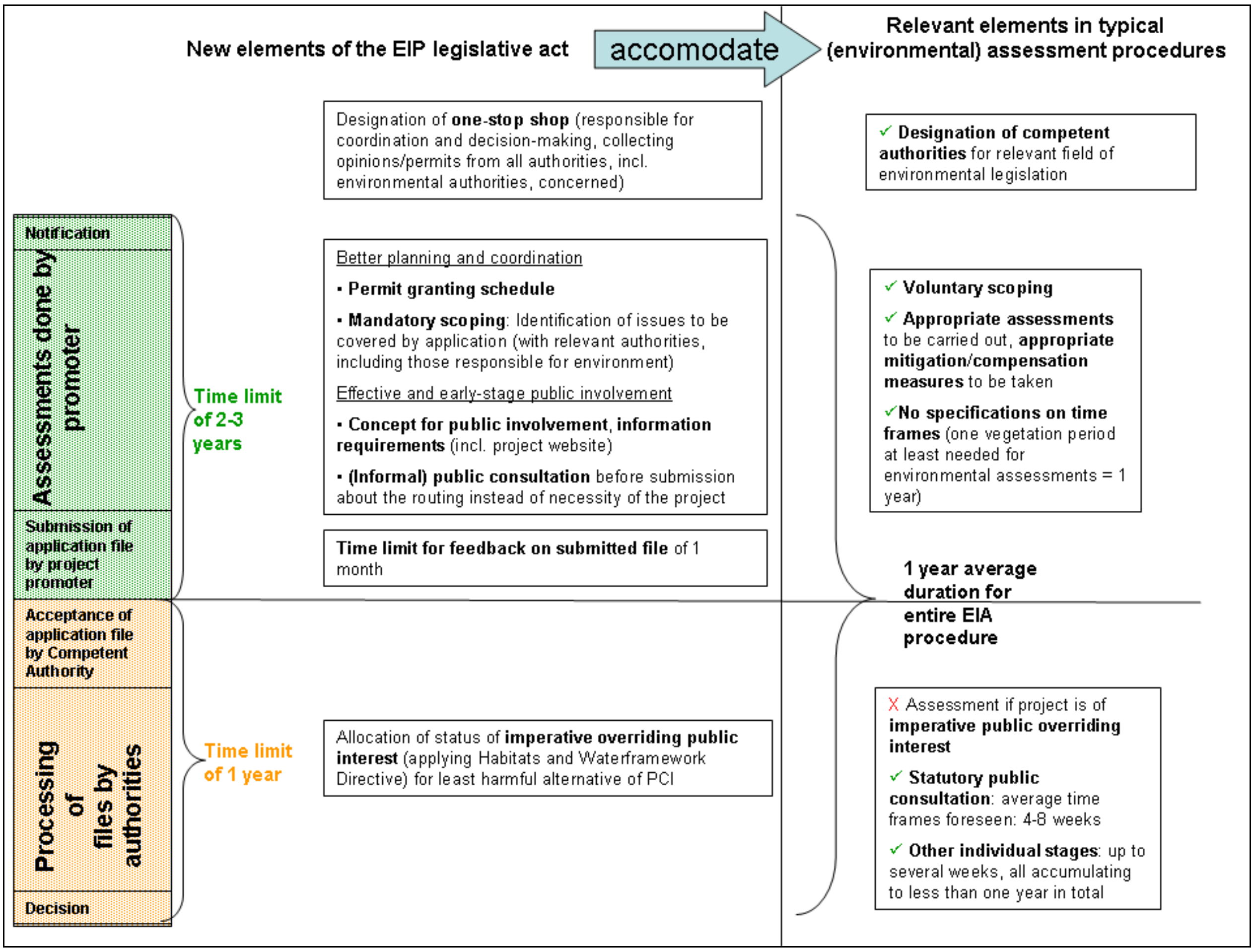

Table 5: Compatibility of measures under Policy Option A.3 with existing permit granting practice and EU environmental legislation

Resulting from this analysis, **policy option A.3 is the preferred option**, combining the measures necessary to achieve the 2020 target.

9.2. Regulation

OPTION B.1: Cost allocation

Suboption B.1.b: *Ex ante* cost allocation mechanism

The **economic impact** of such a measure would be significant, as it would make possible certain investments, for which no viable cost sharing would be possible under BAU. It would do so by changing the way, in which costs for cross-border investments are allocated. Costs would have to be allocated as a function of the expected benefits. In theory, this mechanism could potentially support up to 150 projects in electricity and up to 50 projects in gas[93]. It can however be expected that an effective cost allocation solution will be only found for a certain number of projects, leaving a significant volume of projects with too complex or uncertain benefits unsolved.

It is difficult to assess precisely the **distributional or social impacts** of this option, i.e. how the new mechanism would affect various market participants, but some of them will pay less than under the

93 This estimation is based on the assumption that in electricity, there would be about 100-120 cross-border projects between now and 2020 (the 2010 TYNDP contains 76) and an expected maximum of 30 internal line projects with significant cross-border impact. In gas, there would be about 30 interconnections (without final investment decision), a limited number of reverse flow projects and very few LNG and storage projects with significant cross-border impact. Note that these numbers could be significantly smaller in the case of project clustering.

current cost sharing scheme, while others will pay more. As a general rule, one can expect that TSOs from Member States with large amounts of new variable generation capacities and large consumption needs, notably from electricity imports, are likely to contribute more than before, as these will be the main beneficiaries from cross-border infrastructure development. Those building grids for the needs generated in other Member States are likely to contribute less. In any case, such cost allocation is likely to deliver a more equitable burden sharing among Member States. It should be noted that Member States would be free to compensate for the distributional or social impacts created on their territory, subject to compliance with existing EU legislation in this field.

This option would have a large positive **environmental impact** by delivering projects that are crucial for reaching the 20% share of renewables in 2020. Given the higher number of projects delivered, limited negative impacts, both temporary and permanent, can be expected from this measure on the immediate environment and neighbourhood of projects.

Ex ante cost allocation will have limited **administrative impacts**. NRAs will be required to get involved in the regulation of projects not situated on their territory and to cooperate more in groups with several other NRAs and TSOs from several different Member States. This could create additional needs for human and technical resources. Given its role in assisting NRAs and providing compromise solutions for cost allocation if necessary, it is estimated that ACER would have additional resource needs equivalent to about 1 full time position for every 15 cost allocation cases. Such additional costs would have to be covered under the budget allocated to energy infrastructures.

Concerning the **feasibility** of such a measure, implementing an *ex ante* cost allocation mechanism would require legislative action at EU level to establish the principle, according to which national tariffs might cover costs incurred outside of the territory of the concerned Member State. It is not expected that it would require any national transposition in Member States, but it might require regulatory adaptations in the way, in which NRAs approve investment costs. The establishment of a clear cost allocation principle and a procedure would ensure the framework for cross-border cost allocation negotiations which are done today on a case-by-case agreement with high potential for difficulties or resistance from national TSOs and NRAs to agree on a common cost allocation solution.

The overall effectiveness of this measure is considered to be positive, but insufficient to fully address the investment challenge.

Even assuming a smooth functioning of this new mechanism, *ex ante* allocation will prove impossible for certain projects, leaving a limited number of very complex projects without funding solution. Cost allocation would also not address the problem of insufficient market demand for security of supply projects, notably in gas.

<u>Suboption B.1.c:</u> *Ex ante* cost allocation mechanism with *ex post* adjustment possibility

The impacts of this suboption would be largely identical to the ones of the previous one. The *ex ante* cost allocation mechanism with *ex post* adjustment would however have slightly different **economic and distributional impacts**, as it would allow for changes in the allocation of costs over a given period of operation of the considered infrastructure. This would notably allow to take into account significant changes compared to initial assumptions on generation and load (e.g. if new capacities are added or existing ones withdrawn) or existing transmission capacities (e.g. if a new infrastructure is built in the immediate neighbourhood).

While such a possibility would increase the precision of the allocation mechanism, it would also create financial uncertainty for TSOs and external investors and lenders who will have to take on a downside revenue risk. While such a risk is considered to be acceptable for larger TSOs who fund their projects on a corporate finance basis, it could be unacceptably high for smaller TSOs and for projects funded a non recourse project finance basis. Such risks would in any case have to be covered by a dedicated mechanism.

Implementation of this suboption could also trigger additional **administrative costs**, as TSOs and NRAs could have to re-evaluate benefits and renegotiate cost allocation. . This sub-option may deter in particular other investors, such as third parties, as they may risk the guarantee for cost recovery if ex-post adjustments will take place.

Because of these shortcomings, **suboption B.1.b is the preferred suboption.**

OPTION B.2: Investment incentives

<u>Suboption B.2.a:</u> Risk-related incentives for PCIs

Incentives for PCIs with higher risks would link higher return to higher risks, thereby creating a positive **economic impact** for infrastructure delivery in line with general regulatory principles, while recognising the challenges posed by certain investments. It is expected that PCIs without these higher risks would be implemented would be implemented regardless of the existence of such a scheme and would therefore not be affected. Tailoring incentives for a limited number of projects would reduce the risk of general overinvestment that TSOs would have, in case incentives were offered for all PCIs.

The **financial impact** of such an adder on network tariffs would remain very limited, given that the expected volume of eligible investments is low. Assuming new annual investments of EUR 10 bn (an amount likely to be much larger than the value of new high-risk PCIs every year) and 30% of equity financing for these assets, Roland Berger has calculated that a premium of 2 percentage points would result in an EUR 60 m cost on an annual basis, or about 0.3% of overall transmission costs in Europe, which account for about 5-10% of final electricity and wholesale gas prices only (see Annex 18). The real impact would therefore most certainly be much smaller than EUR 60 m.

As these incentives will mainly benefit offshore grid development and innovative onshore long-distance transmission projects (because of the specific risks related to them), they would also provide significant positive **environmental impacts** in the medium to long term, as such infrastructure would enable deep GHG emission reductions and a much higher share of renewable energy.

Once established, the **administrative impact** for such measures would be limited, given the small number of eligible projects, especially if covered by national tariffs. If paid for by a dedicated fund filled with contributions from national tariffs or congestion rents in electricity, an entity at EU level would have to be tasked with collecting and managing these funds (e.g. ACER).

In terms of **feasibility**, this suboption would need EU legislative action establishing the precise conditions triggering the obligation for NRAs to offer such incentives and rules for the recovery of corresponding costs. In the case of equity adders, national regulators could have to adapt their investment remuneration rules to prevent any cumulative effects with mark-ups existing under national regulation. This could require additional measures, including the modification of national adders.

<u>Suboption B.2.b:</u> Penalties and enforcement action for PCIs

This suboption could in theory, by forcing TSOs to deliver agreed priority projects, increase **social welfare** on European level. The economic impact for the concerned TSOs however could be negative, either because of reduced revenues through the penalties in case of non delivery, or because of additional uncovered risks taken up in case of project delivery. This in turn could affect the capacity of the TSO to deliver on other projects.

Administrative impact of such a measure would be limited. Enforcement of investments would require significant additional work from NRAs and possibly also ACER, though such cases are likely to be very rare, if the penalty/enforcement scheme is designed in a sufficiently dissuasive way.

Concerning **feasibility**, such measures would require conferring new powers to NRAs, which some Member States might resist. They would also trigger strong opposition from TSOs. The added value of such a compulsory scheme compared to a scheme based on incentives seems therefore limited. However, if a future review of these incentive instruments concludes that they are not sufficiently successful in leading to project delivery, a solution based on penalties and enforcement could be studied in more detail.

As a result, suboption B.2.a is the preferred suboption.

OPTION B.3: Ex-ante cost allocation and risk-related incentives for PCIs

This option would be the preferred option, as it would combine the positive impacts of both preferred suboptions and allow covering the largest number of PCIs.

9.3. Financing

OPTION C.1: Risk sharing instruments

Concerning **economic and social impacts**, this option would improve access to capital, as project promoters would be able to use new sources of financing (e.g. bonds), financing on more adapted terms and risk mitigating measures (e.g. guarantees). It would improve the commercial viability of projects and lead to positive investment decisions. Furthermore, the introduction of such instruments will contribute to the extending capital market financing (bonds) to infrastructure and create opportunities in the energy sector for new classes of investors. This overall positive impact will however not apply to projects lacking commercial viability[94]. The decreased cost of financing made possible would also translate into a lower overall cost of PCIs, thereby having a positive impact on network tariffs.

The **financial impact** can only be measured once concrete PCI are identified and their individual characteristics are known. For PCIs with low market demand, risk sharing instruments will not help. Like risk capital instruments, such a form of support would come at a lower expense to the public budget than direct grants. The **multiplying effect** of EU funds used this way could be particularly high: it is estimated that EUR 1 from the EU budget could facilitate up to EUR 25 of overall investment. An assumed EUR 500 m allocated to such instruments could facilitate implementation of projects worth up to EUR 12.5 bn.

Introduction of risk sharing instruments can only be done in cooperation with financial institutions charged with the administration of these instruments. This would reduce the **administrative burden** of the Commission, but additional resources would be needed within the financial institutions for set-up and day-to-day management.

In terms of feasibility, this option should be relatively easy to implement, as it would not require particular legal acts at national level and it not expected to raise opposition from stakeholders[95]. Implementation would need to be in line with the Commission's debt and equity platform.

OPTION C.2: Risk capital instruments

The **economic and social impact** of such a measure would positive, as provision of equity would result in increasing financing capability of projects and additional stimulus for attracting investors and new investor groups. By assisting projects in their early phase, it would contribute to increase and substantially accelerate the pipeline of mature projects, especially if they are more complex, innovative and involve a large number of stakeholders, thereby contributing to delivery of projects of European relevance. However, such instruments are unlikely to help projects lacking commercial viability. They would also require ring-fenced, dedicated project structures, which remain the exception in energy infrastructures. It seems therefore likely that they would only be applicable to a small subset of the needed investments.

As for option C1, the **financial impact** can only be measured once concrete PCIs are identified and the individual characteristics of those projects known. For many PCIs, risk capital instruments will not be the adequate form of support. For suitable projects, a **high leverage** of the EU budget could be expected with a multiplying factor between 1 and 10[96]. Assuming EUR 500 m of dedicated EU budget, up to EUR 5 bn worth of projects could be delivered this way.

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[94] Risk sharing instruments might however help projects close to the point of viability: measures such as e.g. lower cost of financing may make these projects bankable.

[95] Some stakeholders have however argued that such instruments should be made available for all infrastructure projects, not only projects of common interest.

[96] Every euro from the EU would generate between EUR 1 and 10 of investment. The effect could be even higher in case of re-cycling of the budgetary resources during the budgetary period.

The **administrative impact** (for the Commission) will be substantial if equity investments were to be done directly, i.e. without an intermediary financial institution. In line with the equity platform proposal that the Commission is currently preparing, indirect investments (i.e. outsourced to a financial institution) are the more likely solution. This will create substantial resource needs within these financial institutions, equivalent to several full-time positions. Providing seed capital and accelerating project development would also require additional Commission resources, especially for bigger and more complex projects.

In terms of feasibility, implementing this option should not pose particular difficulties, as the Commission has previously implemented similar risk capital instruments both directly and indirectly (Marguerite Fund, Galaxy Fund). No substantial opposition from stakeholders is expected. The implementation would need to remain in line with and draw on the preparatory work done for the Commission's equity platform.

OPTION C.3: Grant support to project construction

The main **economic and social impact** of option would be its very positive contribution to delivering PCIs otherwise not developed by market forces alone as described in section 3.2.1. This would particularly apply to the project categories with high positive externalities but at risk as summarised in Annex 12. The economic impact would be particularly high as the grant intervention would only target the most relevant projects of European relevance, which, if not realised, would seriously hamper the achievement of the 2020 energy and climate policy objectives. Grants will also in particular help those MSs, which contribute most to building PCIs, while not necessarily benefiting most from them. As EU grants are normally excluded from the project value reflected in the Regulated Asset Base (RAB), they will contribute to keeping network tariffs lower than if costs were fully included in the RAB.

The **financial impact** will depend on the amount of projects seeking such support, but our analysis suggests that demand for funds will exceed the amounts that can realistically be made available. It will also depend on the co-financing rate applied to individual PCIs. The underlying principle would be to keep the rate of support at the absolute minimum needed to trigger investment in a PCI. Nevertheless, for some security of supply projects, up to 80% of support compared to eligible costs may be necessary, compared to only about 10% in the lowest cases, thereby reducing the leverage effect of EU funds. Assuming about EUR 8 bn of dedicated EU budget and an average co-financing rate of 30%, grants deliver about EUR 24 bn worth of projects. In addition, grant support would ensure implementation of projects having previously benefited from co-financing for studies, thereby delivering greater overall effectiveness of EU funds[97].

The **administrative impact** for the Commission will be directly correlated with the number of project and the budget available to support them. Such a grant programme would imply centralised management (potentially with the support of an executive agency) and hence require significant additional resources[98].

Finally, this option, as all previous financing options, would have a significant positive **environmental impact** by delivering projects that are crucial for reaching the 20% share of renewables in 2020 and preparing the infrastructure for the longer term EU energy and climate objectives including decarbonisation of energy supply, which could otherwise suffer from the environmental externality problem described above.

In terms of feasibility, implementation of this option should not pose problems. It directly builds on the experience with the implementation of TEN-E and EEPR. The modalities for such a grant instrument are already specified in the existing financial regulation and its implementing rules. Some limited adaptations would be nevertheless required in case of tendering and repayable grants.

OPTION C.4: Combination of grants, risk sharing and risk capital instruments

97 Under the current TEN-E framework, many projects receive co-financing for their studies, but are never realised afterwards, thereby creating substantial sunk costs.

98 For the management of the 44 projects selected under the EEPR, the Commission needs an average of 5 full-time equivalents over a period of 7 years.

As this option combines options C1, C2 and C3, its impacts derive from the **combination of the impacts of the individual options**. But providing a toolbox of market-based instruments (C1 and C2) and direct financial support (C3) will also lead to **synergies and efficiency gains, as it will be possible to flexibly provide the most cost-effective solution** for specific project risks and features. The implementation of some projects will be sufficiently stimulated by risk sharing and/or risk capital instruments, whereas for a limited number of PCIs, grants will be only solution. Consequently the **economic, social and environmental impact would be highest**, as all investments could be supported as necessary in view of implementing the defined infrastructure priorities by 2020, provided the overall amount of about EUR 9.1 bn available EU budget is confirmed. The **financial impact** of this toolbox could be optimised on a project-by-project basis[99].

In terms of **administrative impact**, the combination of various forms of EU level support would inevitably require additional resources within the Commission and for financial institutions. Nevertheless, economies of scale between the different instruments could be achieved through efficient coordination, thereby keeping the burden below the burden level reached if each option were implemented separately. Finally, this option, despite being the most comprehensive response to the identified challenges, would not be more difficult to implement than any of its individual components.

As a result, this option is the preferred one. It reflects the proposals concerning the future EU budget as made by the European Commission on 29 June 2011. It fully reflects the proposed Connecting Europe Facility.

10. COMPARISON OF POLICY OPTIONS

From the analysis in the previous chapter, the following options have been identified as preferred options:

- Concerning permit granting: establishment of a regime of common European interest, full one-stop shop and time limit for projects of common interest;
- Concerning regulation: *ex ante* cost allocation and risk-specific incentives for PCIs;
- Concerning financing: combination of grants, risk sharing and risk capital instruments.

While the establishment of a regime of common European interest is a pre-condition for accelerating the premit granting process, only a full one-stop shop with a unified time limit defined for all projects of common interest can ensure timely delivery of the needed infrastructure investments and thereby also reduce administrative burden.

Ex ante cost allocation and incentives targeted at the most risky projects would ensure delivery of a significant share of projects of common interest, which have assymmetric costs and benefits across borders, use innovative technologies or feature other kinds of specific risks. By keeping the *ex ante* allocation process rather simple, with responsibility for finding solutions first and foremost in the hands of TSOs and NRAs, and by not introducing a complicated *ex post* adjustment mechanism, it strikes the right balance between effectiveness and efficiency.

Finally, only the full combination of all market-based risk sharing and risk capital instruments together with EU grants will allow addressing in the most efficient way the individual needs of projects and theerefore delivering the highest number of projects of common interest, including commercially viable projects with specific risks that can be addressed by risk sharing facilities, complex project at early stage that need to be triggered by seed funding, and commercially non viable, but socio-economically beneficial projects that necessite direct support. The provision of significant amounts of EU grants will be vital to guarantee implementation of all projects at risk identified in chapter 4, as proposed by the European Commission in its Communication on the future budget for Europe.

From the previous analysis, it can be concluded that none of preferred measures in the different policy areas taken alone is capable of delivering the necessary investments, given the multiplicity

[99] The precise allocation of the total budget amount available to risk sharing instruments, risk capital instruments and grants cannot be specified at this stage, as it will require further analysis and be subject to the results of the proposed selection and evaluation process (including cost-benefit analysis) for PCIs.

of obstacles faced. This calls for policy action combining the preferred options identified in each policy area. Indeed, the preferred options can only provide their full benefits in conjunction with the preferred options in the other two policy areas. With more efficient and transparent permit granting, the project pipeline ready for cost allocation or financing will simply not be sufficient to meet the 2020 target. Without appropriate regulatory measures, there is a high risk of delays for cross-border coordination, even if permit granting goes smoothly. It may also imply an inefficient spending of EU funds, as grants could be provided to projects that might have simply required proper cost allocation, or seed capital involvement in projects who could have gone ahead with a regulatory incentive alone. Without appropriate financing instruments at EU level including direct grants, the projects providing large benefits to the EU as a whole without being commercially viable will not be built, leaving also the permit granting and regulatory measures applied before without final success.

Realising the needed investments between now and 2020 will have a significant impact on the cost of transmission, notably in electricity. According to ENTSO-E estimations, EUR 100 billion of new investment would represent on average about 1.5-2€ per MWh (0.15-0.2c€/kWh) of power consumption in Europe over the next 10 years or about 2% of the bulk power prices. This calculation does not take account of possible variations between Member States and the cumulative effect that these investments will have together with the costs for grid refurbishment necessary to replace old infrastructure. According to Commission estimations, total electricity infrastructure investments for the period 2011-2020 could amount to about one to two times the value of the TSOs' existing regulated asset base (RAB)[100]. But this average hides big variations, with certain Member States facing investments worth more than three times their current RAB. Network tariffs could double in certain Member States[101]. Even if the share of transmission costs in overall electricity and gas prices is limited, the impact of this RAB increase on final prices could be significant[102] and compounded by the expected increase of electricity prices due to the cost of national renewables support schemes and could become politically sensitive in different Member States in various parts of the EU. This underlines the benefit expected from providing EU grants to projects with high European but insufficient commercial value.

With the chosen package of preferred options, the negative impacts on the environment, individual citizens and tariffs will be largely outweighed by the benefits expected from the completion of the trans-European networks. This completion will allow achieving the energy and climate targets agreed at EU level, notably the 20% renewables share and the 20% GHG emission reduction by 2020. Adequate infrastructure will also facilitate the full integration of the internal energy market in electricity and gas, thereby creating new opportunities for system optimisation and efficiency, competition and choice for the final consumer and hence exerting a overall lowering effect on energy prices. But it will also make our energy supplies more secure, by providing diversification of sources, routes and counterparts and by increasing system stability, but also by improving the the security and climate resilience of our networks. All this will contribute to the significant positive overall effect on GDP and employment already identified in the 2010 impact assessment (+0.42% of growth and 410,000 additional jobs compared to the baseline scenario over the period 2011-2020). The preferred package of options is therefore considered proportional, effective and efficient with regard to the objectives pursued. Table 6 below summarises the impacts of all options and suboptions.

Options	**Economic and social impacts**	**Environmental impacts**	**Other impacts**
A.1 Regime of Common	+	=	Legal feasibility: -

[100] The RAB is a valuation concept to determine the value of assets detained by a TSO. The closing regulatory asset base at the end of a period is equal to the opening asset base at the start of that period plus any new capital expenditure less any depreciation that occur during the regulatory period. Several TSOs have confirmed that their RAB is set to double over the period 2010-2020.

[101] Commission calculation. While the relationship between an increase in investments and the corresponding increase in tariffs is complex, depends on many factors (evolution of electricity consumption, operational expenses, losses, system services and other costs) and differs from Member State to Member State, it is possible to make approximations with regard to the tariff impact.

[102] In a Member State where network costs make up for 10% of the total electricity bill, a 100% increase of these costs would increase electricity prices by 10%.

Options	**Economic and social impacts**	**Environmental impacts**	**Other impacts**
European Interest			
A.2 full one-stop shop and time limit of 4 years	++	+	Legal feasibility: -
A.3 Regime of Common European Interest, full one-stop shop and time limit of 4 years	+++	++	Legal feasibility: -
B.1 Ex-ante cost allocation	++	+	Administrative: -
B.2 Risk-related incentives for PCIs	++	+	Tariff impact: -
B.3 Ex-ante cost allocation and risk-related incentives for PCIs	+++	++	Administrative and tariff impact: -
C.1 Risk-sharing instruments	+++	+	
C.2 Risk capital instruments	++	+	Administrative: -
C.3 Grant support for project construction	+++	++	Administrative: -
C.4 Combination of grants, risk sharing and risk capital instruments	+++	++	Administrative: - Tariff: +
A3 & B3 & C4	+++	+++	Legal, administrative: - Tariff: +

Table 6: Summary of impacts (= equivalent to baseline; + to +++ improvement compared to baseline; - to - - - worsening compared to baseline)

11. MONITORING AND EVALUATION

In line with the measures proposed in the preceding IA, the following specific indicators would be used to monitor the evolution of the policy:

Concerning the general implementation, by 2020, of projects of common interest necessary to implement the trans-European energy infrastructure priority corridors as defined by the February 2011 European Council conclusions:

- The general progress achieved for each project of common interest selected under the defined priority corridors (number of projects planned, under construction or commissioned; installed capacity and, if applicable, length of lines): This will be monitored on the basis of regular reports from project promoters and national regulators.
- The interconnection level between Member States and the corresponding 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, price differentials between major European hubs could be used. Price monitoring is already being done by DG ENER's Energy Market Observatory;
- For electricity, the installed capacities for electricity generation from renewable sources, with a specific focus on offshore wind generation. This will be monitored through the biennial reports Member States must submit to the Commission under article 22 of the renewables directive;

- For gas, the share of each import source in overall imports (at national, regional and EU level) and the compliance with the N-1 and reverse flow. The latter two will be monitored under the Security of supply Regulation.

a) Concerning permit granting procedures and public involvement and acceptance:

  - the average and maximum total duration of authorisation procedures for projects of common interest in electricity and gas;
  - the duration of each step of the authorisation procedure for projects of common interest, compared to the timing foreseen by the initially agreed project milestones;
  - the level of opposition faced by projects of common interest (number of written objections during the public consultation process, number of legal recourse actions).

The data in this section will be monitored on the basis of regular reports from project promoters and Member States.

b) Concerning the regulatory treatment of projects of common interest:

  - The number of projects of common interest having reached a cost allocation agreement among TSOs and NRAs;
  - The average duration for reaching an cost allocation agreement;
  - The number and type of projects of common interest having received specific incentives and/or support by NRAs;

The data in this section will be monitored on the basis of regular reports from project promoters and national regulators.

c) Concerning market-based and direct EU financial support:

  - The total value of annual investments in electricity and gas transmission, storage and LNG/CNG, compared to total investments during the period 2007-2013;
  - The annual value of EU funds engaged compared to the total value of beneficiary projects of common interest, for each instrument and as a whole;
  - The timeliness of disbursing engaged EU funds, both for market-based instruments and EU grants, compared to initial project milestones and corresponding reasons.

The Commission would ensure monitoring and evaluation via an implementation report on a bi-annual basis, a mid-term evaluation in 2017 and a final evaluation. In addition, the Commission proposes to set up a transparency platform allowing the general public to follow the advancement of individual projects of common interest.

ANNEX 1
GLOSSARY

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
EBRD	European Bank for Reconstruction and Development
EIA	Environmental Impact Assessment
EEPR	European Energy Plan for Recovery
EIB	European Investment Bank
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
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIE	Gas Infrastructure Europe
GW	Giga Watt
IA	Impact Assessment
ICT	Information and Communication Technology
ITC	Inter-Transmission System Operator Compensation
LNG	Liquefied Natural Gas
MS	Member State
NRA	National Regulatory Authority
NSCOGI	North Sea Countries Offshore Grid Initiative
PCI	Project of Common Interest
RAB	Regulated Asset Base
RES	Renewable Energy Sources
TEN-E	Trans-European Networks for Energy
TFEU	Treaty on the Functioning of the European Union
3^{rd} IEMP	Third Internal Energy Market Package
TPA	Third Party Access
TSO	Transmission System Operators
TWh	Tera Watt hour
TYNDP	Ten-Year Network Development Plan
WACC	Weighted Average Cost of Capital

ANNEX 2
INPUT DOCUMENTS

The impact assessment builds on the results of the following studies, some of which have already been used for the 2010 impact assessment (marked by an asterisk):

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ANNEX 3

RESULTS FROM THE PUBLIC CONSULTATION ON PERMIT GRANTING

Executive summary

Adequate, integrated and reliable energy networks are a crucial prerequisite for EU energy policy goals and for the EU's economic strategy. The European Commission has therefore, in its Communication "Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network" put forward a strategy for a new European energy infrastructure policy. In autumn 2011, the Commission will table a legislative proposal, identifying the tools necessary for the implementation of this policy. As widely acknowledged, one of the main obstacles impeding and delaying energy infrastructure development are long and non-transparent permit granting processes, along with a lack of public acceptance. Therefore, the Commission has been assessing possible solutions to ensure effective and time-efficient planning and coordination, good administrative practice as well as a more transparent and inclusive decision-making and communication approach.

In this context, as part of the process of preparing the legislative proposal, a public consultation was launched, which was open from 1 March - 30 April 2011.[103] 81 replies were received – 13 from Member States, 57 from the industry and related organisations, 1 academic contribution and 10 from civil society, namely citizens and NGOs. Contributions from the industry were provided by system operators (transmission as well as distribution), producers, the renewable industry and chambers of commerce as well as other industry associations. This report summarises the contributions received.

Public consultation questions and summary of replies:

***Question 1** Measures to facilitate the administrative procedures: "one-stop shop", time limits, and rewards and incentives:*
The introduction of binding time limits and a "one-stop-shop" (of some form) were welcomed by an overwhelming majority of respondents (60 % and 79 % respectively[104]). Issues raised were national competence, the degree of decision-making power of the competent authority and the avoidance of additional administrative structures. 30% of respondents supported the provision of rewards and incentives to facilitate project development while 20 % opposed this measure.

***Question 2** Guidelines to increase the transparency and predictability of the permit granting process:*
Guidelines were mostly considered useful. The three issues that were raised most often were a better communication strategy for the economic and social benefits of infrastructure projects, the full and early provision of environmental information and thus an earlier involvement of the public in infrastructure planning (e.g. providing and explaining grid expansion plans). Member States stressed that especially in communicating with the public the subsidiary principle has to be respected.

[103] http://ec.europa.eu/energy/infrastructure/consultations/20110430_infrastructure_projects_en.htm
[104] with approximately 20 % not expressing a clear preference

Question 3 *Improving public acceptance of infrastructure projects:*
Overall responses indicated that the main responsibility for communication should be with the project developer, but that local, regional, national and European authorities should facilitate these measures (depending on the project) and provide political support. An early discussion of possible environmental and health risks, a better communication of the purpose of infrastructure projects by the TSOs and the inclusion of more stakeholders in the planning process were considered suitable measures by several respondents.

Question 4 *Compensation mechanisms to facilitate infrastructure projects:*
Roughly half of the respondents were opposed to the harmonisation or standards for compensation mechanisms across the EU and believed that the competence here should remain within the Member States. Other respondents, mainly from the industry, believed that some form of standardisation can be helpful, especially with respect to cross-border projects.

Question 5 *Experience with national best practices:*
Several best practices were reported that were successfully addressing different issues, e.g. longer pre-application procedures, a central coordination body within the ministry, a national grid development plan or non-monetary compensation measures for affected communities.

Detailed summary

Adequate, integrated and reliable energy networks are a crucial prerequisite for EU energy policy goals and for the EU's economic strategy. The European Commission has therefore, in its Communication "Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network" put forward a strategy for a new European energy infrastructure policy. In autumn 2011, the Commission will table a legislative proposal which will put forward the tools necessary for the implementation of this policy.

A long and uncertain permit granting process was indicated by many major stakeholders as one of the main reasons for delay of infrastructure projects. The time between the start of planning and final commissioning of a power line is frequently more than ten years, assumingly preventing up to 50% of commercially viable projects from being realised by 2020. Reasons are manifold: Non-transparent permit granting procedures, coupled with lack of political support as well as the opposition of affected citizens. Cross-border projects face additional opposition, as they are frequently perceived as mere "transit lines" without local benefits.

The Commission is therefore assessing how to improve the administrative procedures existing in the Member States, to ensure an efficient upfront planning of the permits, time-efficient coordination and good administrative practice. The permit granting process should also be made more transparent for all stakeholders and the general public, and communication with the affected population needs to be improved.

In this context, as part of the process of preparing the legislative proposal, a public consultation was launched, which was open from 1 March - 30 April 2011.[105] The public consultation was based on a questionnaire of five open questions addressing the following issues:

1. measures to improve **administrative procedures** ("one-stop shop", time limits, rewards and incentives)
2. introduction of guidelines to increase **transparency and predictability**
3. improving **communication with citizens** to ensure higher public acceptance
4. requirements for **compensation mechanisms** at individual and community level
5. existing **best-practices** at national level to facilitate the permit granting process.

81 replies were received –**13** from **Member States**, **57** from the **industry and related organisations**, **1 academic contribution** and **10** from **civil society**, namely **citizens and NGOs**. Contributions from the industry were provided by system operators (transmission as well as distribution), producers, the renewable industry and chambers of commerce as well as other industry associations. The individual contributions have been published on the public consultation's webpage.[106]

The broad spectrum of respondents offers an insight into a large range of stakeholder opinions.

Question 1: *As explained above [see consultation document], a complex and non-transparent procedural framework as well as poor administrative practice are major reasons for delays. There are different options which could help to facilitate administrative procedures. These include, as outlined in the Communication "Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network", the establishment of a national contact and coordination body ("one-stop shop") per cross-border project, the introduction of a time limit, and the provision of rewards and incentives to regions or Member States which facilitate the permit granting process. Would you consider these measures as useful? If so, under which conditions? Are there any additional measures you would propose to facilitate the administrative procedures?*

The proposed measures were generally welcomed as an attempt to tackle the existing problems and delays in administrative procedures. Whilst agreeing with certain suggested provisions, different stakeholders pointed out that such facilitation was necessary not only at European level but at national level as well. Projects of Common Interest should similarly enjoy the same political support in the Member States as national priorities.

"One-stop-shop"

The idea of a central contact and coordination body for the permit granting procedures received overwhelming support (79 % of respondents supported the measure while only 2 respondents (~ 2.5%) opposed it). The advantages of a single entry point for permit applications were pointed out across all different stakeholders. This would limit the number of required permissions significantly and enable a coordinated publication of environmental and

[105] http://ec.europa.eu/energy/infrastructure/consultations/20110430_infrastructure_projects_en.htm
[106] http://ec.europa.eu/energy/infrastructure/consultations/20110430_infrastructure_projects_en.htm

other information. The communication with the public would become smoother, which can benefit the acceptance of infrastructure projects among the population.

It was pointed out that projects at national level should clearly remain national competence and in this context half of the Member States opposed a standardisation of procedures as different approaches already exist in a number of countries. EU-coordination for cross-border projects exclusively received support.

Another question that was often addressed was the competence of the proposed "one-stop-shops". Here the preferences were almost equally split between a pure coordination centre and a body with significant decision-making power with industry responses slightly favouring more centralised decision-making power. Many proponents made clear though that either measure should not create additional administrative structures.

Time limits

Time limits were supported by a majority of respondents, with 60 % being in favour and 10 % opposing the idea. Particularly NGOs warned of the risks of introducing inappropriate time limits. Several supporters of time limits suggested maximum limits for each individual step of the application procedure or at least benchmarks to make the process more transparent.

A central issue that was also raised were the consequences if a deadline was not met by the authorities. Automatic acceptances could decrease public acceptance significantly, while automatic rejections shift the consequences back to the project developer. Other examples have a higher decision-making authority reviewing the files in case of a bureaucratic delay.

Some critics state that simply introducing time limits, though possibly beneficial, will not erase the root causes of slow administrative processing. It has to be ensured that the authorities' staff capacities are sufficient to guarantee smooth permit granting process.

Arguing along those lines, many of the opposing respondents called for appropriate time frames to guarantee a thorough and correct permit granting process and enough time for an adequate consultation process. Some Member States saw general maximum time limits as an obstacle when dealing with more complicated projects (e.g. new technologies). A diligent examination of the environmental impacts was also considered to be beneficial.

Rewards and incentives

Rewards and incentives as a means to encourage smoother administrative processes faced more opposition, particularly from Member States and NGOs. In contrast most industry responses expressed a positive attitude toward the measure.

The reasons for opposition stemmed mainly from 3 reasons:

- Stakeholders see a problem in defining objective criteria to assess the permitting agency's work. In this light rewards and incentives might be perceived as buying consent and be detrimental to public acceptance.
- The introduction of rewards and incentives cannot replace a diligent consultation and permit granting process and hence does not contribute to alleviating the root causes of administrative delays.
- Some responses queried the source of funding for this measure.

Instead of financially incentivising smooth processing respondents emphasized that administrative capacities of the authorities involved should be strengthened and best practices and benchmarks should be encouraged.

Additional issues

The already existing European coordinators for cross-border projects were mentioned positively. In this context, maintaining the possibility to resort to coordinators as political support for crucial cross-border connections was suggested by several stakeholders.

A discrepancy was noted between the existing European environmental, urban planning and industrial hazards laws and the objective to develop a European energy infrastructure. Therefore some Member States and individual industry responses called for a joint effort of the different Directorates-General to promote and facilitate the framework for energy infrastructure development. It was pointed out that a better coordination and clear priorities among the different objectives could shorten the permit granting process significantly.

Question 2: *To increase the transparency and predictability of the permit granting process for all parties involved, guidelines targeted at ministries, local and regional authorities, project developers and affected citizens could be developed. Would you consider them useful? Which issues should they address?*

The introduction of guidelines to foster transparency and predictability was considered useful by a clear majority of respondents, especially among Member States and stakeholders from civil society. Several Member States stressed that the subsidiary principle has to be respected, particularly when communicating with the public.

Many respondents emphasised that the wider economic and social benefits of infrastructure projects need to be better communicated. The significance of transmission lines in general and each specific project has to be highlighted in order to increase public acceptance and achieve better compromises. Environmental organisations highlighted that the purpose of the connection (e.g. integration of renewable energy sources) should be communicated to the wider public. The specific benefits of a connection (e.g. decarbonisation, security of supply) could also have favourable or in other cases negative effects on the public opinion.

The full and early provision of environmental and technical information was also considered an important measure to facilitate public acceptance. In this respect a minimum standard of communication – regarding the amount and the timing during the process – was suggested by several stakeholders. This approach enables earlier involvement of the different stakeholders in the process, which was widely favoured by respondents. Reconciling a more transparent process (with possibly more stakeholder involvement) with the need to speed up existing procedures was named as a major challenge for these measures.

To guarantee more transparency regarding network development, the requirement for a national development plan or a network strategy was proposed. Plans similar to ENTSO-E's TYNDP would make further network expansions more predictable and comprehensible. The UK's National Policy Statements (NPS) set a clear strategy for further network development and also explain the evaluation process of applications in more detail. Laying open all steps of the process and the evaluation criteria can foster trust in the permit granting process and thus support in projects.

Procedural reliability was valued as very important for all stakeholders. A clear prescription of responsibilities and tasks for each stakeholder at the different moments of the process was suggested in this respect. For cross-border projects a solid method for cost-allocation was called for, as well as a harmonisation of procedures to enable these projects further.

Question 3: *The lack of public acceptance poses a major hindrance for the implementation of energy infrastructure projects, and the associated achievement of energy and climate policy objectives. What should be done, apart from efforts to increase general transparency, to improve communication with citizens at an early stage of the project and to ensure that the environmental, security of supply, social and economic costs and benefits of a project are correctly understood? Who should be responsible for /involved in this communication?*

Next to a more transparent process (covered in question 2) respondents addressed 3 main areas:

A more proactive information policy regarding energy infrastructure development, particularly from the TSOs' side: A further explanation of their activities and the purpose of new projects were deemed highly important. The different stakeholders agreed that creating awareness for the necessity of grid expansion is going to be a key factor. The projects have to be better linked to the wider benefits, a sustainable energy future – connecting grid expansion to security of supply, the integration of the internal market and efforts to tackle climate change.

In this regard respondents were in favour of a more integrative planning procedure, also encompassing NGOs, academia and other stakeholders. Some environmental NGOs pointed out that in light of a coherent strategy they were willing to support grid extension measures and their promotion, which could prove crucial for public acceptance. Furthermore it was suggested that independent research institutes could play a role, examining the actual environmental and health risks of power lines and informing the public. Recognising and addressing the population's concerns seriously was also named as a measure to foster trust and a higher acceptance in the long run.

Respondents were very clear that the main responsibility of communication should be with the project developer but many stakeholders also advocated more direct political support for grid expansion to further stress the necessity of the measure. This was particularly mentioned for the European level, but also local and regional support for individual projects was considered helpful and relevant.

Question 4: *Requirements for compensation mechanisms: In your opinion, could minimum or harmonised requirements on compensation of affected populations, targeted at individual or community level, help to increase public acceptance? Which* *compensation schemes would you deem useful, and who should provide for the compensation?*

Compensation mechanisms were broadly seen as helpful or necessary, if fair and transparent. Industry responses stressed that the additional costs connected to compensation measures were to be included in higher tariffs and hence carried by the consumer. A question that arose is an acceptable method to calculate compensation for intangible negative effects (e.g. visual impediment).

Respondents believed that compensation should be exclusively a national decision and opposed any standardization due to diverging circumstances (e.g. land prices, public involvement, specific projects) in the Member States. This rejection was the clearest among Member States. It was also mentioned several times that compensation measures should remain exceptions and thus dealt with case by case in cooperation with local authorities. Individual industry responses on the other hand were favourable toward some form of minimum standards and guidelines.

Compensation targeted at individuals and communities were seen differently. Individual compensation measures for landowners were perceived as unavoidable in order to have the right to use one's property. If community compensation proved to be beneficial to public acceptance, it was seen as a fair and good approach to reimburse communities for negative impacts. A majority of respondents preferred a case by case approach – with local and regional authorities playing a major role in agreements – and were opposed to any automatism. Concerns of not creating some sort of business were also expressed.

The issue of adequate compensation for environmental impact, though addressed by environmental directives, was raised by several respondents.

Question 5: *Have you encountered any national best-practices which have helped to facilitate the permit granting process? Which measures were taken in view of administrative procedures, transparency and communication with citizens, and how has the public responded?*

A wide array of examples was named, pointing to approaches in different Member States that proved to be successful in alleviating challenges in the administrative procedures, transparency and communication. These examples included national "one-stop-shop" approaches as well as a transparent central planning strategy. They underlined beneficial results of introducing time-limits and other streamlining measures (e.g. a thorough pre-application process). Furthermore they also pointed to successful efforts to better communicate benefits to the public and better integrate their concerns via a transparent public debate. Examples showed that certain measures can improve public acceptance of infrastructure development. These best practices will be studied and taken into account.

Not completely accounting for every measure mentioned, a few of the submitted examples are briefly presented in the following:

- In the Netherlands the RCR ("Programma Rijkscoordinatieregeling") makes the Dutch Ministry of Economic Affairs, Agriculture and Innovation the central coordination body for projects of national interest. Permits are still granted by local and regional authorities but the ministry sets deadlines and publication dates. In certain cases, the ministry can grant the permit on behalf of the local or regional authorities. Besides coordinating the permit granting process it takes the decision on the spatial planning. This coordinated process allows for the publication of all information at the same time, enabling transparency and providing citizens the opportunity to engage at a central point of the process. One-stop-shop approaches in other countries were also praised for facilitating the permit granting process (e.g. Greece, Ireland and Austria).

- The National Policy Statements (NPS) in the United Kingdom are an example of an overarching infrastructure development strategy setting out the Government's energy policy. It explains the need for new energy infrastructure and contains further instruction on how to assess project applications and the impacts of energy infrastructure projects. The NPSs thus increase the transparency and predictability of the permit granting process by defining the main issues and objectives considered for granting the permit. Setting a clear and long-term oriented energy policy is also described as a facilitating measure in Slovakia.

- Organised public debates by a national commission gives the general public in France the opportunity to voice their opinion and influence major planning and construction projects in advance of any decision being taken. Although it prolongs the process up-front it can prove beneficial for public acceptance and help to avoid subsequent appeals and other hold-ups. The Swedish experience similarly shows that spending more time and attention in the pre-application phase – consulting with all stakeholders concerned by the project and making all documents relevant to the decision process public – can speed up the overall process.

- In Portugal a cooperation between environmental NGOs, the national conservation agency (ICNB) and power line construction companies agreed to include rules for mitigation of impacts on bird populations in their planning and construction guidelines.

- To change the fact that the broader population is often unaware of the TSOs activities and goals, the Belgian TSO, ELIA, launched several successful media campaigns. They inform the general public about its activities, policy goals and ongoing projects and explained the reasoning and benefits of further infrastructure development.

ANNEX 4
OUTCOME OF STAKEHOLDER CONSULTATION AMONG TRANSMISSION SYSTEM OPERATORS

1. ENTSO-E

ENTSO-E carried out a survey among 41 European TSOs in 34 countries. Six main barriers to investments are considered by TSOs: social acceptance, planning delays, few investment incentives (in particular for R&D and innovation), and the lack of stable return on investment as well as the uncertainty about future regulatory regime change. Cross-border projects require a reinforcement of the national grids. Public funding should be targeted to address specific project/country risks and with a competitive approach to the label and support.

More detailed responses were provided by:
- Amprion (Germany)
- Eirgrid (Ireland)
- Elia (Belgium)
- EMS (Serbia)
- 50 hertz (Germany)
- HTSO (Greece)
- MAVIR (Hungary)
- REE (Spain)
- RTE (France)
- Statnett (Norway)
- Swissgrid (Switzerland)
- Terna (Italy)
- Transelectrica (Romania)

Financing of infrastructure in the past

For past investment mainly corporate financing was used and projects were implemented together with adjacent TSOs, investment expenditure being covered in the CAPEX of the TSOs concerned. Next to debt and equity financing, auction revenues from cross-border capacity allocation are used to fully or partially finance interconnectors (only one TSO referred to this financing). Upfront pre-construction investments are mainly financed by 100% equity. Debt capital can hardly be attracted for this type of investment. Among the main constraints to investment, TSOs raised the following issues:
- Time-lag in the remuneration of invested capital during the construction phase (pre-financing and start-up losses, of particular importance when projects are delayed by permitting or acceptance problems)
- Transmission fees do not cover all costs linked to the internal reinforcement of the grid linked to connection of new RES generation (shallow transmission fees, 1 TSO),
- Lack of incentives for technology innovation and R&D or other risks,
- Projects that will face particular challenges relate to offshore developments or submarine cables and for some countries interconnector investments.

Recommendations for future financing and EU support

In the light of the new and urgent investment challenges, TSOs will need to attract equity and debt financing and new investors. Asked about the added value of EU support, TSOs recommend financial support to the construction phase. Some TSOs note that the most effective measure is to ensure sufficient rate of returns for all projects and rate of return markups for projects of major importance and to align the RORs to the risks faced by project owners.

2. ENTSO-G

The consultation of TSOs among ENTSO-G included detailed responses by:

- GAZ SYSTEM
- Gasunie
- National Grid
- Thyssengas
- GEOPLIN PLINOVODI
- RAG
- DESFA
- ENGAS
- GRTgaz
- OMV
- Wingas
- Fluxys
- FGSZ
- NET4GAS

Financing of infrastructure in the past

Past investments were financed on the basis of corporate financing within the structure of the parent company on the basis of equity and shareholder loans complemented by EU direct grants and EIB loans. Depending on the degree of ownership unbundling and international expansion, the experience with credit ratings, corporate bonds, project financing and direct exposure to capital markets differs widely. Project financing was mainly used for new LNG terminals and new interconnectors in Western Europe. Project bonds and project financing via special project vehicles are being examined for future investment by TSOs outside of the national network. The attractiveness of these bonds will largely depend on the costs.

Recommendations for future financing and EU support

ENTSOG Members underlined that new gas projects aiming to increase diversification, competition, market integration and security of supply, thus removing market Imperfections, will not come forward by relying on market (shippers) commitments alone. While volume risk is covered in regulated gas networks, fluctuating utilization, the short-term tariff setting and capacity allocation do not fit to the long-tem investment cycles.

Future EU support should minimize investment lead times and construction risks, reduce the administrative burden on project promoters, offer coordinated political support to decrease country risks in geopolitically difficult regions, enhance cross-border cooperation and the coordination of open seasons. The EU should support should be targeted to the entire investment cycle including feasibility and routing studies, environmental impact assessments (EIA), land and building permit design as well as the construction of projects.

Cost allocation should be enhanced by multilateral negotiations of investment projects at regional level between operators and regulators with strategic guidance by ACER and ENTSOG. In practical terms, TSOs in the respective Member States could book the capacities needed for security of supply and include these costs in their respective transmission tariffs. Other options include settlements through direct cash transfers between TSOs or through netting system using EU funds granted to the Member States concerned.

While ENTSOG members unanimously call for instruments to make projects bankable along the long term investment cycle, they consider various instruments depending on the particular needs of the TSOs. These range from credit enhancement, to public/private guarantees (for example through the

EIB), European public private investment funds, harmonized investment conditions and performance-related incentives as well as direct EU grants and a dedicated EU fund for infrastructure.

3. Gas Infrastructure Europe (GIE)

Investment in regulated and non-regulated infrastructure in the gas sector requires a long-term commitment either by regulators or users. Given the regulatory and market trends towards short-term capacity, GIE underlines that tariffs and investment regulation should give long-term signals for investment. New financing instruments should be beneficial to all projects. Costs of stranded assets remain with consumer in the case of regulated networks. Risk profiles change as gas TSOs are about to unbundle or restructure the ownership. Gas TSOs will need to invest in IT and human resources to handle the growing capacity and congestion management with short- and long-term products.
Among the measures suggested by GIE are the following:

- Cost-allocation mechanism is mentioned in cases, where the lack of user commitment could be substituted by cross-border compensation.
- Adequate risk/reward ratios and tariff to ensure long-term signal and not only short-term low rates of return
- Incentives for operators – performance-related rewards for implementation of network development measures, independent of and on top of the allowed revenues, including shortened amortization period in order to limit risks. GIE sees higher risks for cross-border projects due to inconsistent regulatory frameworks on two sides of the border and higher complexity.

ANNEX 5
ENERGY INFRASTRUCTURES PRIORITIES

The priorities for the period up to 2020 are the following:

a) In electricity:
   - Developing an offshore grid in the North Sea, the Irish Sea, the English Channel and the Baltic Sea and reinforcing and building new onshore North-South interconnections in Central Europe;
   - Developing interconnections in South-Western Europe;
   - Strengthening the electricity networks in Central Eastern Europe and South Eastern Europe in North-South and East-West electricity flow directions;
   - Developing interconnections between the Baltic Member States and their Union neighbours and reinforcing internal grid infrastructures accordingly;
   - Implementing the deployment of smart grid technologies across the Union;

b) In gas:
   - Developing the transmission of gas in the Southern gas corridor;
   - Developing interconnections between the Baltic Member States and their Union neighbours and by developing interconnections in Central Eastern and South Eastern Europe in North-South direction;
   - Increasing interconnection capacities for North-South gas flows in Western Europe;

c) In oil:
   - Reinforcing the interoperability of the oil pipeline network in Central Eastern Europe.

The two longer-term priorities are the development of electricity highways and CO2 transport networks.

ANNEX 6
TYPICAL PROJECT DEVELOPMENT PROCESS FOR AN ENERGY INFRASTRUCTURE PROJECT AND EXAMPLES OF PROJECTS HAVING FACED PERMIT GRANTING DELAYS

Figure 1: Typical project development process

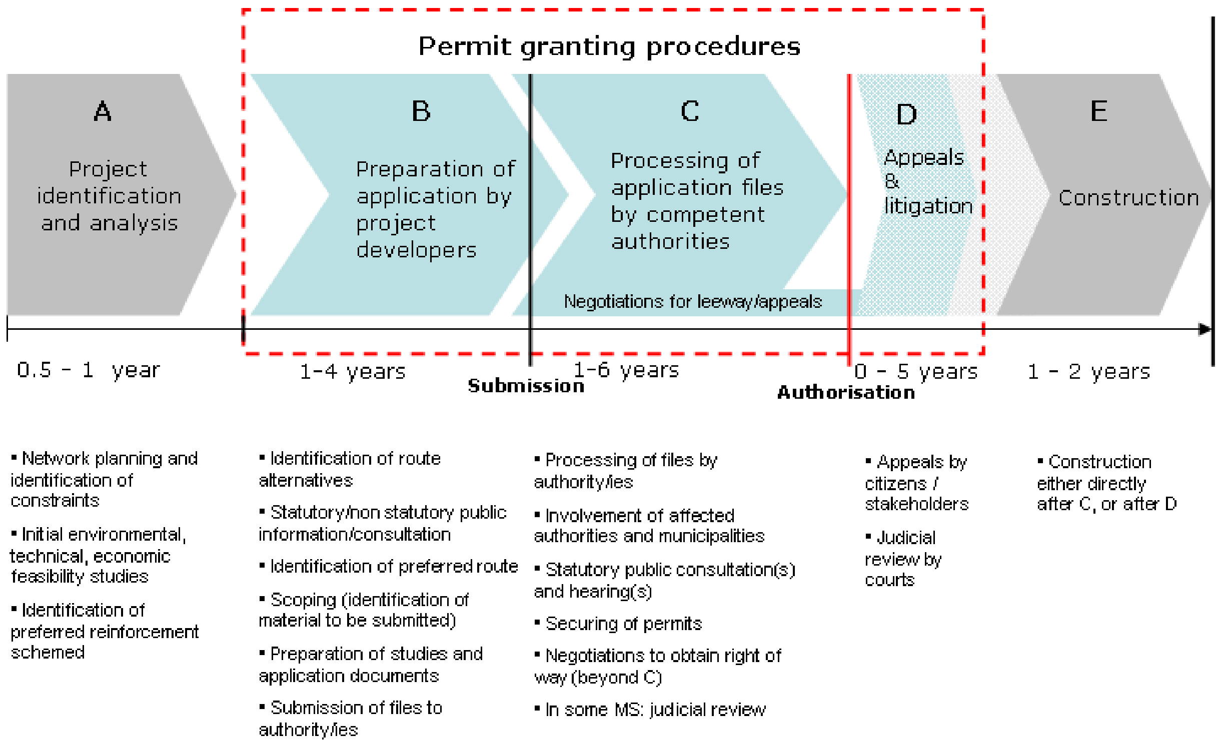


Table 7: Projects having faced permit granting problems

Member State	Project	Duration of the permitting procedure	Problems encountered
Austria	Steiermarkleitung, 380 kV electricity line	1982-2007*	Lengthy administrative procedures, public opposition
	Salzburgleitung, part St- Peter – Salzburg, 380 kV electricity line	1995-2010*	Introduction of EIA requirement throughout the procedure, delays in administrative and litigation procedures
Estonia – Finland	Ulvila, Kangasala, 400 kV electricity line	2003-2008	Public opposition and lengthy litigation procedures
	Estlink	2001-2006	n/a

Member State	Project	Duration of the permitting procedure	Problems encountered
France	Nantere – Nourottes, 225 kV electricity line	2001-2009	Lengthy administrative procedures
	France – Lyon – Chambery connection, 400 kV electricity line	1999-2006	Lengthy administrative procedures
France-Spain	French-Spanish interconnector, 380 kV electricity line	1970s-2014* (expected, including construction)	Lengthy administrative procedures for some parts of the project, strong public opposition
Germany	Interconnector Halle/Saale-Schweinfurt, 380 kV electricity line	2006-2013 (expected)	Public opposition, lengthy administrative procedures, environmental requirements
	Windcollectionline Mecklenburg Vorpommern – Schleswig Holstein, 380 kV electricity line	2005-2013 (expected)	Lengthy administrative proceedings with differences across federal state borders – one part of the project is constructed, the other part waiting for permission
Germany/ Netherlands	Niederrhein – Doetinchem, 380 kV electricity line	2009-2014+ (expected, including construction)	Delays due to cross-border issues in planning procedures (cross-border point not fixed in NL – necessary to start the procedure in DE)
Greece	High pressure gas pipeline to Aliveri	2006-2011 (expected)	Lengthy administrative procedures, environmental requirements, lack of resources
Hungary/Romania	Hungarian-Romanian 400 kV electricity line	2003-2009	Land acquisition issues, including administrative formalities
Hungary/Slovenia	Hungarian-Slovenian 400kV electricity line	2000-2012 (expected)	Lengthy procedures due to environmental requirements
Italy	Sorgente-Rizziconi, 380 kV electricity line	2004-2009	Public opposition due to environmental concerns

Member State	Project	Duration of the permitting procedure	Problems encountered
	Turbigo-Rho, 380 kV electricity line	1994-2004	Conflicts with regard to routing through densely populated and environmental protection areas
Spain	Martorell-Figueras high pressure gas pipeline	2006-2011	Lengthy procedures, particular complexity of the projects needing consents from several regions
Sweden	Stenkullen Lindome 400kV electricity line	2004-2010	Lengthy administrative procedures and high number of authorities involved
UK	Beauly-Denny, 400kV electricity line	2005-2010	Public opposition, environmental requirements
	Second Yorkshire Line Project, 400 kV electricity line	1991-1998	Lengthy administrative procedures, public opposition

*including planning and pre-application efforts. For all projects where these efforts are not included, an average of 2 years for pre-application has to be added.

ANNEX 7
KEY DATA ON PERMIT GRANTING PROCEDURES IN SELECTED MEMBER STATES

Country	AT	BE	BG	CZ	DE	DK	EE	EL	ES	FI	FR	HU
Duration and delays												
time limits for statutory process	Y	N	na	Y	partly	N	na	Y	partially	N	N	Y
real average duration	3 years*	4 years	na	4 years	8 years	10 years	na	5 years	3* years	6 years	5.5 years*	2 years*
Authorities and permits												
number of permits	>1	5	na	3	1	2-3	na	1	>3	3	3	3
responsible authorities	>1	na	na	na	>2	2-3	na	1	>10	8-10	1-2	3-10
Fast-track procedure existing	Y	N	na	N	Y	N	na	Y	Y	N	N	N

Country	IE	IT	LT	LV	NL	PL	PT	RO	SE	SK	Sl	UK
Duration and delays												
time limits for statutory process	Y	Y	N	partially	partially	partially	partially	N	N	N	N	Y
real average duration	4 years	5 years	4 years*	3 years*	1.5 years*	4 years*	1.5 years*	3.5 years	9.5 years	4 years*	7.5 years	4 years
Authorities and permits												
number of permits	1	1	3	3	1	>3	2	>4	2	4	4	1
responsible authorities	1	1	several	>5	1	>3	>1	25	>2	>2	4	1
Fast-track procedure existing	Y	Y	N	N	Y	Y	N	Y	N	N	N	Y

*pre-application efforts to be added (average 2 years)

SUMMARY:	Time limits (partially or entire procedure)	13 MS
	1 responsible authority at national level	5 MS
	Fast track schemes	10 MS

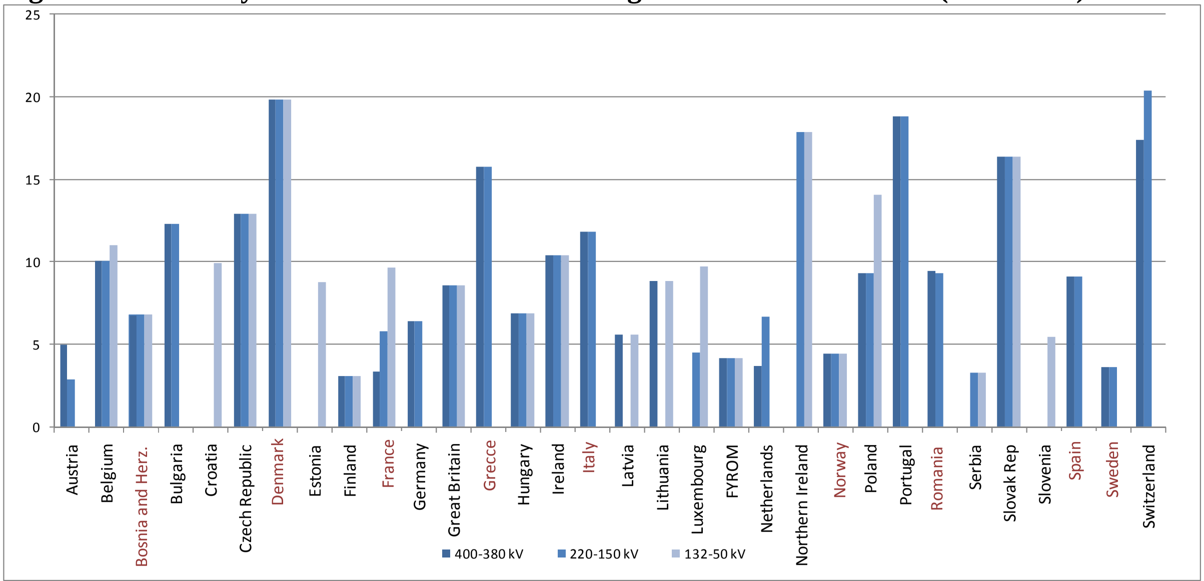
Sources: Consultation of TSOs, Roland Berger study on permitting, individual interviews

ANNEX 8
MAIN REASONS FOR PUBLIC OPPOSITION TO ENERGY INFRASTRUCTURE PROJECTS

- **Unclarity about the added value of a project**: The public generally questions the necessity of a project. Usually, it is up to the promoter to communicate the benefits and costs of a project, without support from authorities. The efforts needed to communicate and convince the public about the necessity and the benefits of a project can lead to major delays of up to one year.
- **Impacts on the environment and landscape, health and safety concerns:** Public opposition is particularly strong for electricity overhead lines, because of the (at times perceived) impact of power lines on the environment, and landscape (the notion of the "Not in my Backyard" (NIMBY) phenomenon has in the past been frequently quoted, where citizens agree to the general objective of a project but refuse its construction in their vicinity), as well as safety and health concerns, especially with regard to electro-magnetic fields. Additional resistance arises as cross-border projects are perceived as mere "transit lines" without local benefits. Gas installations are usually less affected by public resistance, but difficulties have occurred with some LNG and storage sites and gas pipelines.
- **Late and insufficient involvement of the public and stakeholders**: An effective dialogue with the public, i.e. landowners/citizens and stakeholder organisations, is essential to gain public acceptance. However, in many cases, the public is not consulted at the very beginning of the project and is hence not adequately involved in the decision-making process. The perception to be confronted with precooked decisions has in many cases provoked substantial opposition. Further, due to the complexity of the process it is often unclear for citizens at what stage and how they can intervene, particularly when public consultations are carried out repeatedly on the same issue but within different procedures.

ANNEX 9
NATIONAL ELECTRICITY AND GAS MARKET STATISTICS

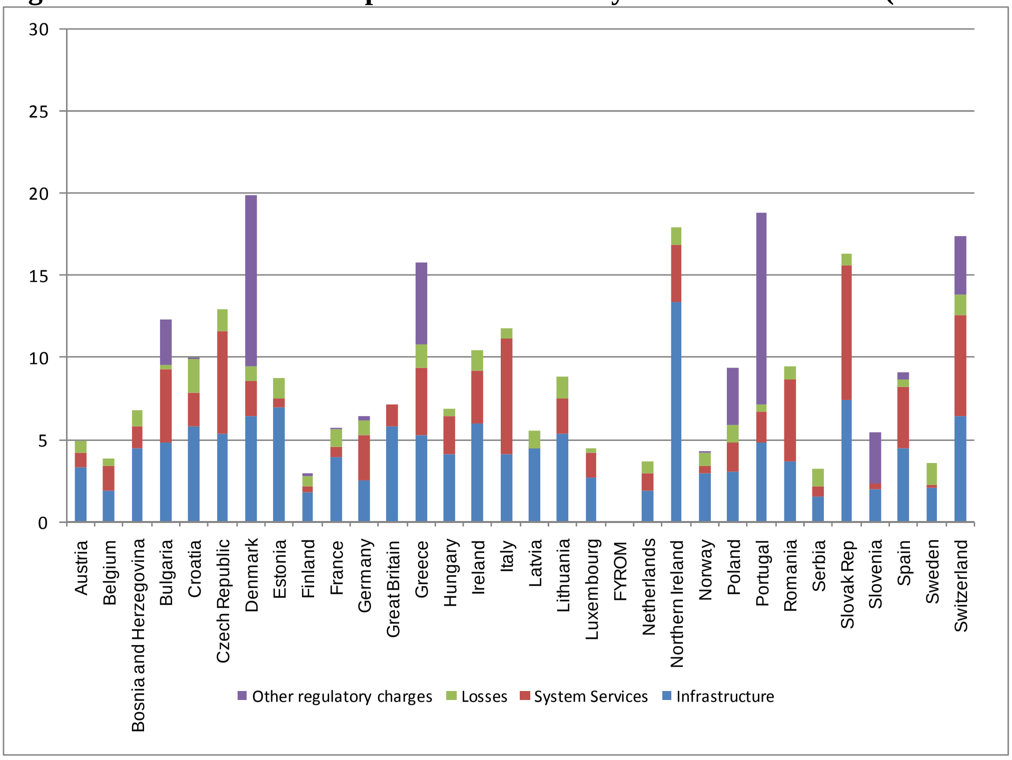
Figure 2: Electricity transmission tariffs – sum of generation and load fees (in €/MWh)



Source: ENTSO-E, 2011

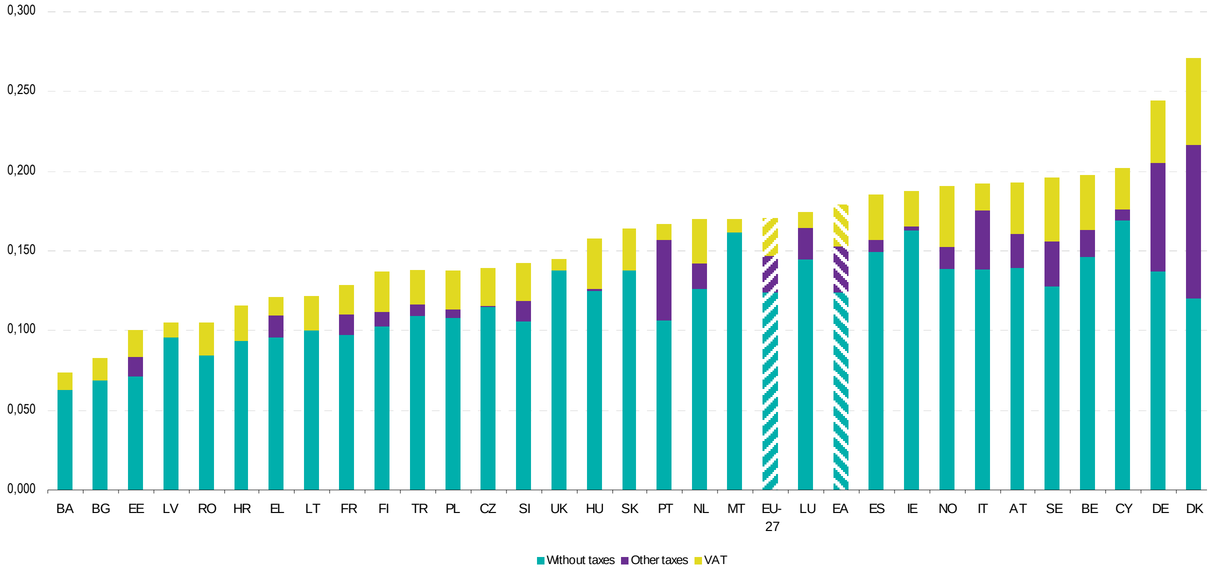
(Those countries, for which certain elements of the 2010 transmission tariffs are estimates are marked in red.)

Figure 3: Infrastructure components of electricity transmission tariffs (in €/MWh)



Source: ENTSO-E, 2011

Figure 4: Electricity prices for household customers, 2nd semester 2010 / 2010s2 (in €/kWh)

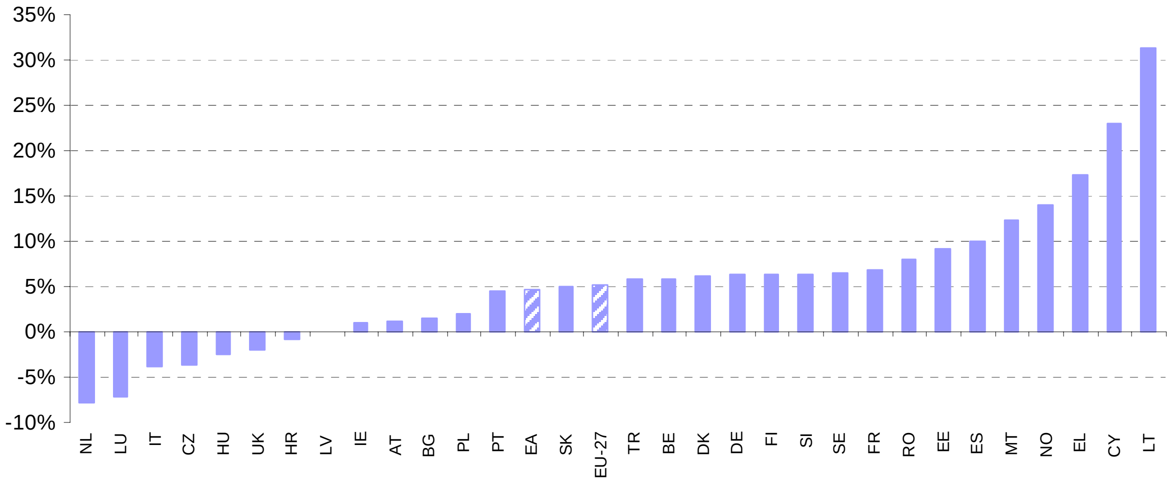


Source: Eurostat (data for Italy provisional). EA designates the euro area.

Figure 5: Electricity prices for household customers, 2010s2 (in PPP/kWh)

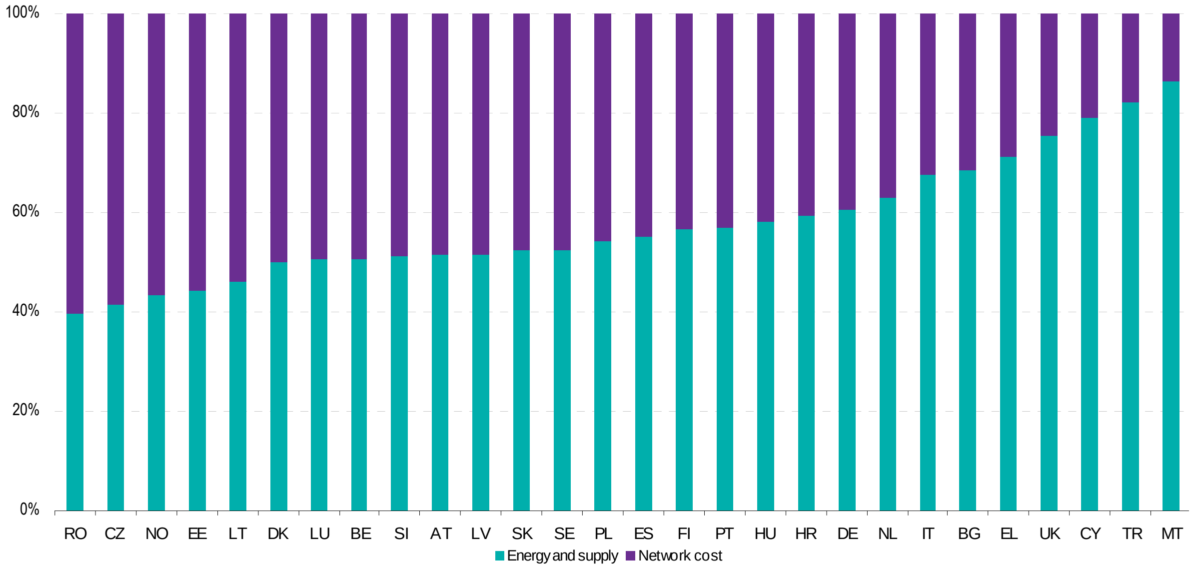
Source: Eurostat (not available for Bosnia and Herzegovina)

Figure 6: Percentage change in electricity prices for household consumers, 2010s2-2009s2



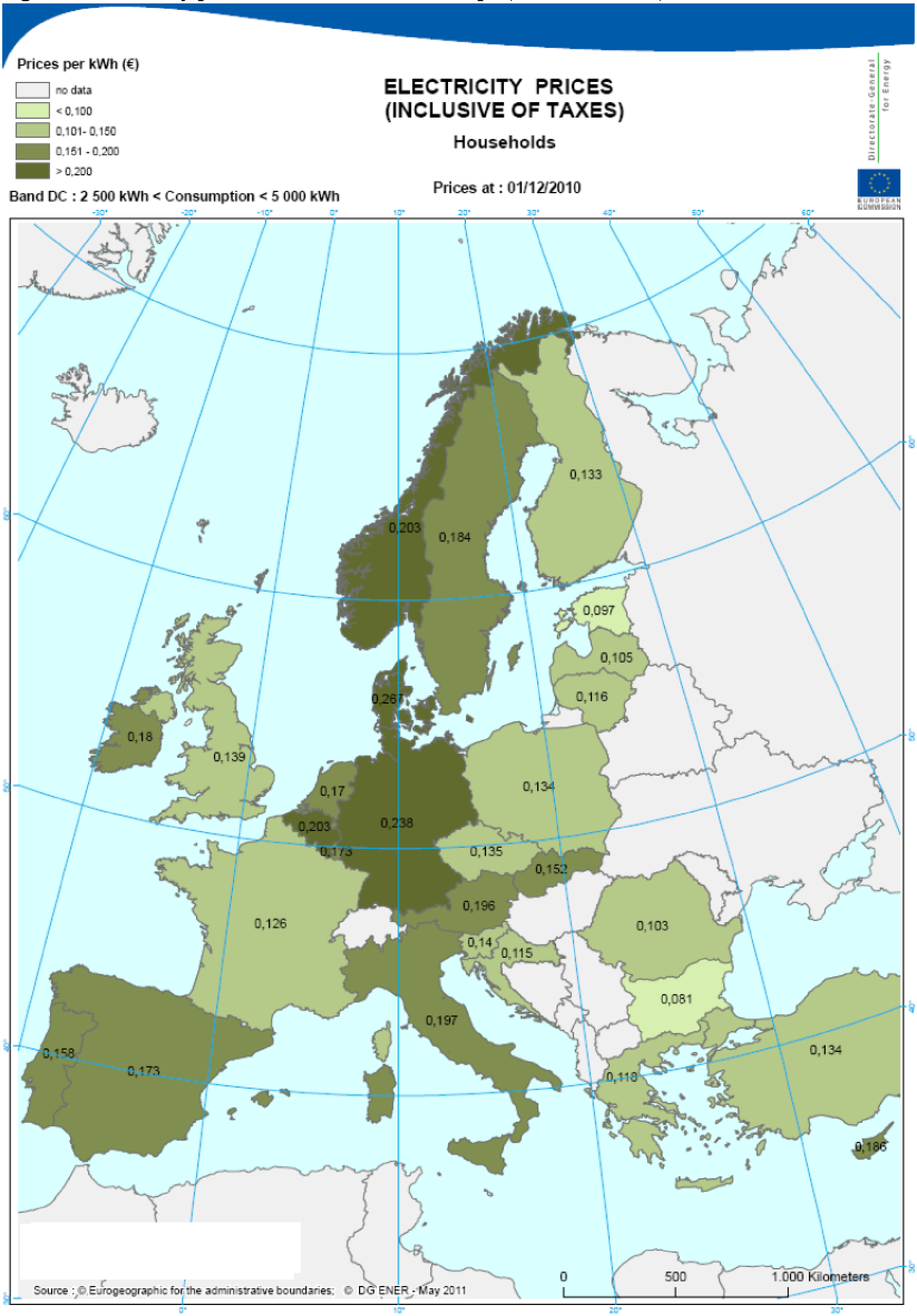
Source: Eurostat

Figure 7: Share of network costs in electricity price for household consumers, without taxes, 2010s2 (in %)



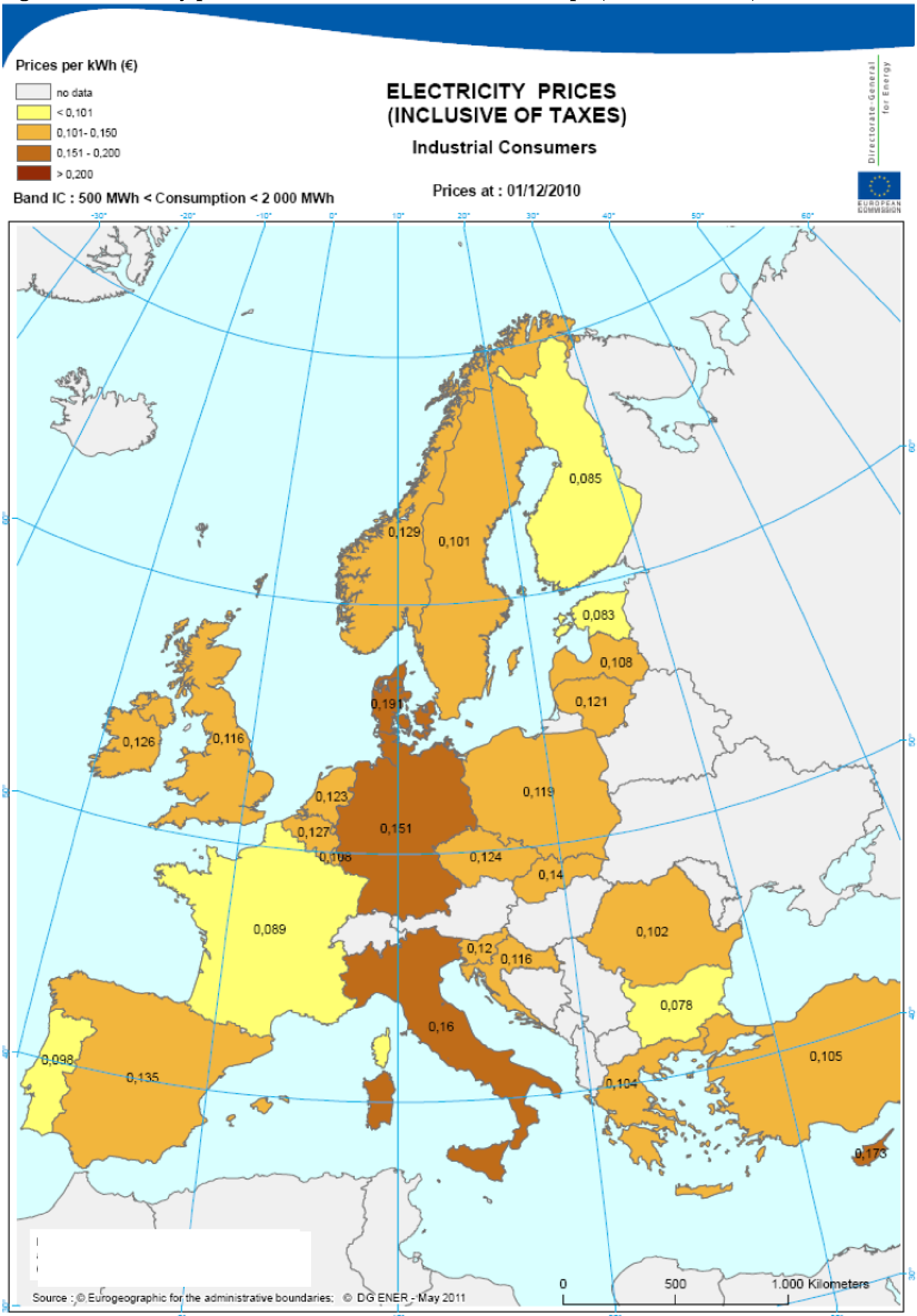
Source: Eurostat 2011 (data for Italy provisional, no disaggregated price data for Ireland, France and Bosnia and Herzegovina)

Figure 8: Electricity prices for households in Europe (December 2010)



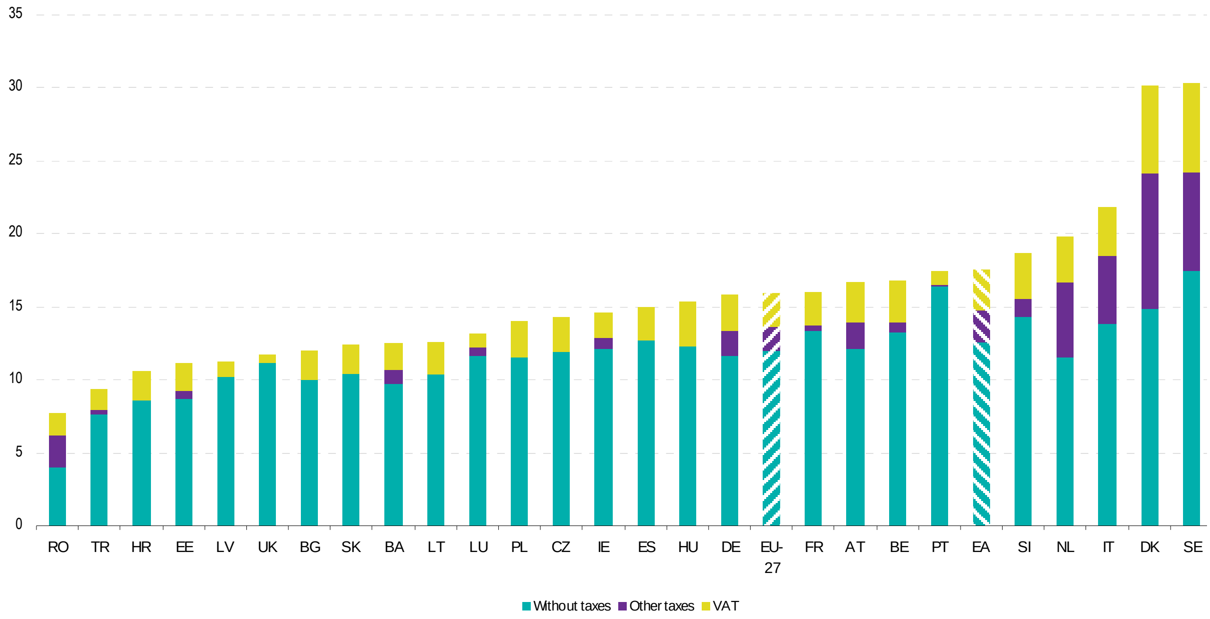
Source: DG Energy, Market Observatory, 2011

Figure 9: Electricity prices for industrial consumers in Europe (December 2010)



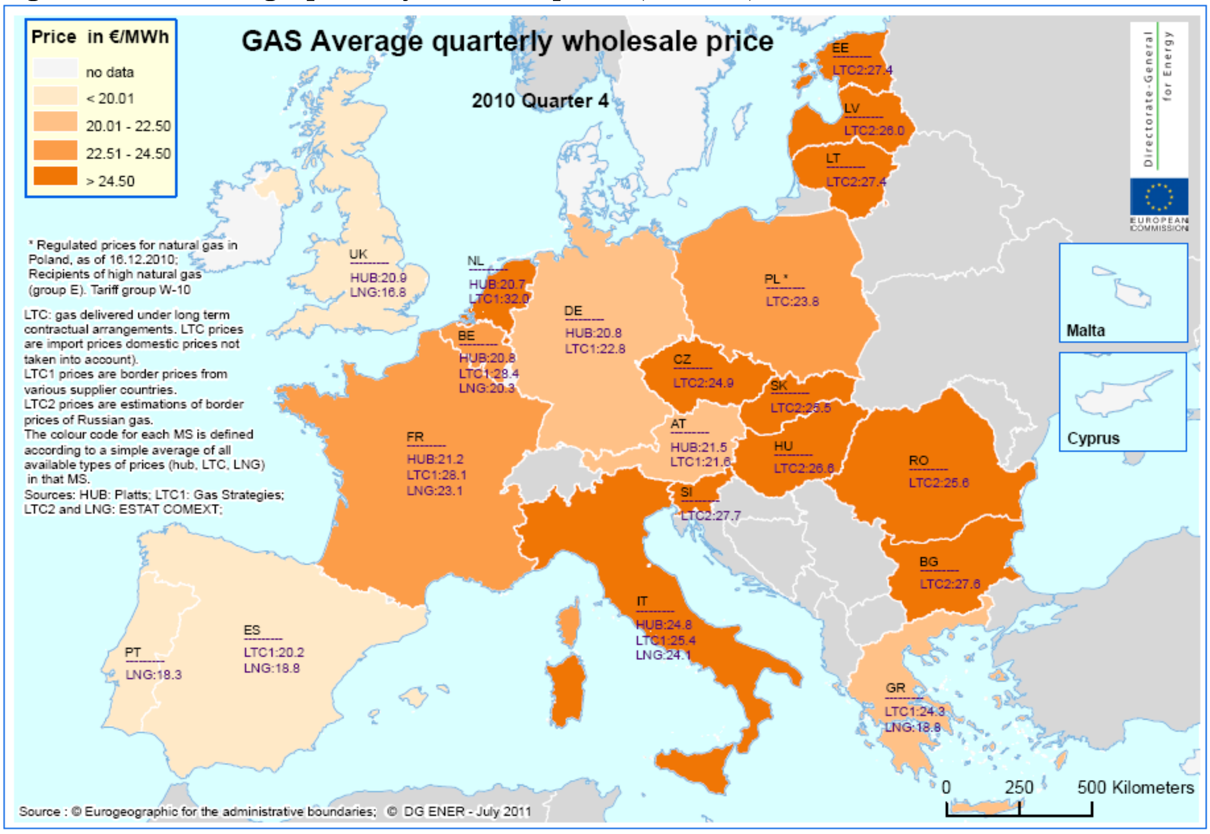
Source: DG Energy, Market Observatory, 2011

Figure 10: Natural gas prices for household consumers, 2010s2 (€/GJ)



Source: Eurostat (data for Italy provisional)

Figure 11: Gas average quarterly wholesale prices (Q4 2010)



Source: DG Energy, Market Observatory, 2011

ANNEX 10
ELEMENTS OF NATIONAL REGULATORY FRAMEWORKS FOR ELECTRICITY AND GAS INFRASTRUCTURE

Table 8: Remuneration of electricity infrastructure investments in selected Member States

Country	Type of remuneration	Calculation	Rate
Austria	WACC	pre-tax nominal	6.32%
Czech Republic	WACC	pre-tax nominal	7.65%
Germany	RoE (pre 2006) RoE (post 2006)	pre-tax real pre-tax nominal	9.29% 7.56%
Greece	WACC	pre-tax	8%
Spain	WACC	post-tax	7.6%
Finland	WACC (electricity)	pre-tax, status 2006	6.5%
France	WACC (electricity)	pre-tax	7.25%
Hungary	RoE		4.5%
Ireland	WACC	pre-tax	5.95%
Italy	WACC (electricity)	pre-tax	6.9%
Lithuania	WACC (electricity)	Pre-tax nominal	5%
Netherlands	WACC (electricity)	Pre-tax nominal Pre-tax real	6.9%-8.4% 5.3%-6.7%
Portugal	WACC (electricity)		7.8%
Great Britain	WACC	post tax cost of equity	5.05%

Source: Roland Berger, 2011

WACC: Weighted Average Cost of Capital
RoE: Return on Equity

Table 9: Overview on investment related aspects of the national regulatory frameworks for gas

Country	Type	Length of regulatory period	TOTEX approach	Investment allowances	CAPEX time shift gap	RAB based on replac-ement cost	RAB based on historic costs	RAB based on indexed historic costs
Austria	Rate-of-Return						x	
Belgium	Revenue cap	4 years				x	x	
Bulgaria	Rate-of-Return							
Czech Republic	Revenue cap	5 years						x
Denmark	Rate-of-Return							x
Estonia	Price cap							
Finland	Revenue cap	4 years					x	
France	Revenue cap	5 years		x	x			x
Germany	Revenue cap	5 years (as of 2013)	x	x	x	x	x	x *depending of the*

Country	Type	Length of regulatory period	TOTEX approach	Investment allowances	CAPEX time shift gap	RAB based on replac-ement cost	RAB based on historic costs	RAB based on indexed historic costs
								year of purchase
Great Britain	Revenue cap	5 years						x
Greece	Revenue cap							x
Hungary	Revenue cap	4 years				x		
Ireland	Revenue cap	4 years						x
Italy	Revenue cap	5 years					x	
Lithuania	Price cap	5 years					X *financial accounts*	
Luxemburg	Rate-of-Return							x
Netherlands	Price cap / yardstick	4 years	x	x	x			x
Portugal	Rate-of-return						x – *standard cost*	
Romania	Revenue cap	5 years						x
Slovakia	Price cap	3 years			x	*Tariffs based on price benchmarking*		
Slovenia	Price cap	1 year (3 years in the future)					x	
Spain	Price cap	4 years	x	x			x	

Source: KEMA study 2009.

Table 10: Remuneration of gas infrastructure investments in selected Member States

Country	Type of remuneration	Calculation	Percentage
Austria	WACC	post-tax (pre-tax	6.97% (8.3%)
Belgium	WACC	pre-tax real	6.21%
Czech Republic	WACC	(pre-tax nominal) post-tax nominal	(8.289%) 6.13%
Germany	RoE (pre 2006) RoE (post 2006)	pre-tax real pre-tax nominal	9.29% 7.56%
Finland	WACC	pre-tax nominal status 2006	9-10%
France	WACC	pre-tax real	7.25%
Greece	WACC	(pre-tax nominal) pre-tax real	(10.06%) 6.56%
Great Britain	WACC	pre-tax real	6.25%
Hungary	WACC	pre-tax real	6.9%
Ireland	WACC	pre-tax real	5.2%
Italy	WACC	pre-tax real	6.7%
Lithuania	WACC	pre-tax real	6.87%
Luxemburg	WACC	pre-tax nominal	8.5%
Netherlands	WACC	pre-tax real	5.5%
Portugal	WACC	pre-tax real	8.0%
Romania	WACC	pre-tax real	7.88%
Slovenia	WACC	pre-tax real	5.87%
Spain	WACC	post-tax nominal	5.48-5.68%

Source: KEMA study 2009

ANNEX 11
PROJECT CASE STUDIES CONCERNING REGULATORY AND FINANCING ISSUES

1. ELECTRICITY

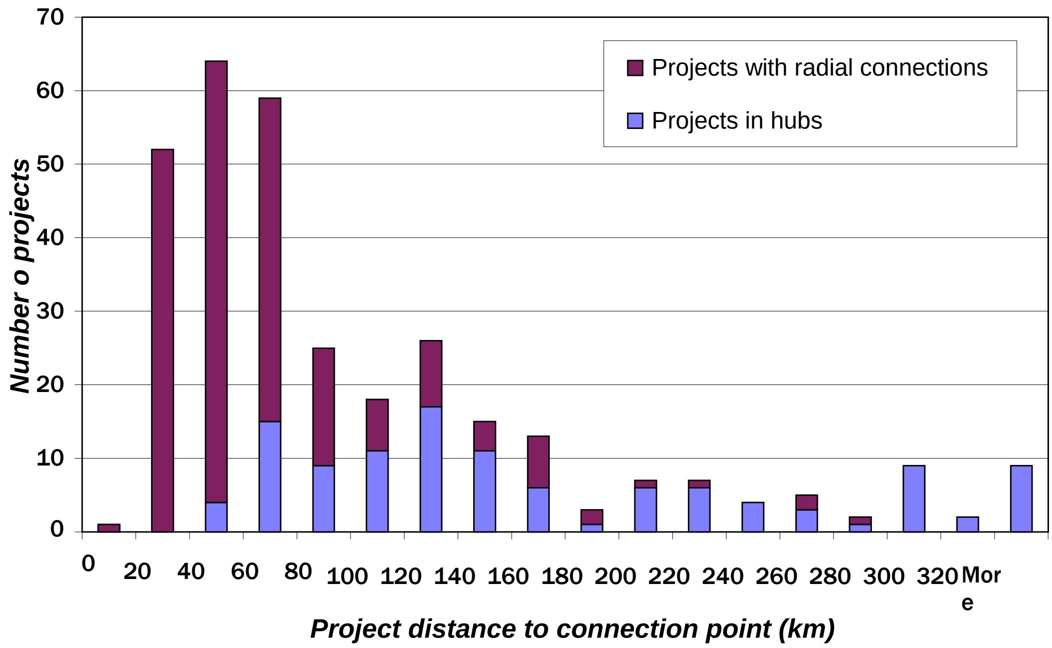
1.1. Offshore grid

The development of an **offshore grid** in the Northern Seas poses specific challenges by combining the connection of offshore wind (or other) energy sources and cross-border interconnection for electricity trade[107]. The benefits of such a grid can be measured e.g. according to installed wind generation capacity in each country or electricity flows to coastal countries, with both methodologies yielding very different results in terms of cost allocation. Existing national regulatory frameworks do not provide adequate rules for such allocation and realising synergies by combining connection projects or connection and interconnection projects. Nor do they regulate appropriately onshore connection, prioritisation between electricity in-feed and trade flows or the offshore grid's added value in ensuring onshore system security and ancillary services.

- According to the OffshoreGrid study, a total of about 320 offshore wind projects are forecasted to be online by 2030, totalling about 150 GW in Northern Europe. Based on its analysis of optimal connection solutions for offshore wind farms depending on their distance to shore, concentration and size, the OffshoreGrid study concludes that more than one third or almost 55 GW should be connected via hubs rather than radially as is the case today (cf. Figure 12), mostly in the North Sea and, to a lesser extent, the Baltic Sea[108]. Moreover, opportunities for T-connections of offshore wind parks to interconnectors have been identified for the following development areas:

– North and Irish Seas: BorWin, HelWin and SylWin (DE); Idunn and Sorlige Nordsjoen (NO); Irish Sea R9, Firth of Forth and Dogger Bank (UK) for a total of about 30 GW;
– Baltic Sea: Baltic 1 (DE); Kriegers Flak (DE, DK and SE); Blekinge Taggen and Södra Midsjöbanken (SE); several wind farms in Polish waters for a total of about 6 GW.

Figure 12: Projects connected radially and via hubs in 2030 ***(Source: OffshoreGrid study)***



[107] See Annex 4 of SEC(2010) 1395 for a more detailed description.
[108] While Germany would host by far the biggest number of these hubs (about 60), Member States benefiting from such a solution could include Belgium, Denmark, Finland, Netherlands, Poland, Sweden and the United Kingdom.

Already for the period up to 2020, the study has identified about 30 offshore wind projects in Germany and the Netherlands, but also Finland – totalling about 9 GW –, for which a hub connection would be the optimal socio-economic solution. These numbers can be compared with those of national regulators of the North Seas Countries Offshore Grid Initiative who foresee installed offshore wind generation capacity to increase from about 4 GW to 40 GW by 2020, of which about 22GW should be further out to sea. As regards offshore interconnectors – most of which are or would be regulated –, new projects to be implemented by 2020 total 15 GW, compared to current total interconnection capacities of about 7 GW in the region[109].

As stated by the NSCOGI working group on regulatory and market aspects: "Typically, at present, new interconnectors or shared lines are developed on a 50:50 shared cost basis between the connected TSOs. While this traditional approach works at present while lines are between two countries, it may be more challenging to develop appropriate and fair cost allocation rules when lines begin to connect more than two countries or are connected to offshore generation. This issue is not specific to offshore grid development, but will arise more generally as more cross-border infrastructure is built on land across Europe."

The **Kriegers Flak project** is an excellent example of the concrete difficulties encountered when trying to develop offshore transmission infrastructure in an integrated manner. It initially envisioned the development of three wind farms within German, Swedish and Danish waters, linked by a combined offshore grid connection, which would also serve as an interconnection between the three countries. The three-country solution has in the meantime been abandoned with Sweden's withdrawal, and the development of the project has been delayed because of regulatory challenges, despite EUR 150 million of EU funding received in the context of the European Energy Program for Recovery.

Three different TSOs were involved (Vattenfall, Energinet.dk and Svenska Kraftnätt), as well as two market systems and two synchronous zones, posing a huge challenge regarding regulation on cross-border infrastructure. The feasibility study, published in a joint report of the three TSOs, concluded that the combined solution would generate positive net benefits compared to the separate solution (reduced price differentials between markets, spot market development, security of supply), but also imply higher upfront costs (EUR 1.36 bn compared to EUR 1.29 bn for a smaller solution) and more risks and require close coordination between the transmission companies in the area. The current regulatory framework does not incentivise this, as it is mainly national in scope and targeting the improvement of internal services and cost savings instead of promoting a regional approach. Additionally, there are other regulations that might also distort the incentives to cooperate, such as different rules for renewables connection, balancing or renewables support in the three countries[110].

1.2. Lithuania-Poland interconnection (LitPol link)

The planned 150 km DC interconnection between Lithuania and Poland aims at connecting the Baltic States to the EU continental system with a capacity of 2x500 MW. Total investment costs are estimated at EUR 237 m. 100 km of this DC line will run through Polish territory while 50 km will be on Lithuanian territory. The participating TSOs have set up a special purpose vehicle, LitPol Link.

The interconnection will considerably enhance the security of supply of the Baltic States and end the isolation of the entire region. The link is essential for the integration of the Baltic States to the EU electricity market.

Major obstacles for the LitPol link are related to the difficult discussions with land owners on the Polish side, where on average 50 to 80 owners are involved per km on average, and to the potential environmental impacts of an overhead line. The business case of the project is also closely linked to the Polish participation in the NPP project in Lithuania.

[109] NSCOGI Working group 2, "Report to the Steering Committee", June 2011.
[110] Meeus et al., 2010

1.3. Smart grids

For the deployment of smart grid technologies, distribution system operators could in many Member States bear the major part of costs for a the corresponding investments, while not necessarily being the only or even main beneficiaries. Smart metering has developed most in those Member States, where the benefits arising from two-way communication are clear and go directly to the party bearing the investment cost[111]. The deployment of smart networks on a larger scale however has proven to be difficult, as the benefits they provide are spread among multiple actors of the system. According to analysis of demand response schemes in the United States, about 80% of the value created by such schemes go the savings in generation capacity costs, 10% to savings in energy costs and 10% to the reduction of transmission and distribution costs (through e.g. the delayed need for new investments)[112]. This translates cost-benefit asymmetries among the actors concerned by smart grid developments. Eurelectric estimates that distribution system operators who will pay for the vast majority of investments needed, might only reap around 60% of the benefits. As long as no cost allocation solution can be found, which includes other beneficiaries such as final consumers or generators, rapid deployment of smart grids will be seriously impaired.

2. GAS

2.1. MidCat Pipeline – North-South Gas corridor in Western Europe

MidCat is a 800 km natural gas interconnector linking the French and Spanish gas markets from Barbaira (France) to Catalonia (Spain) including bi-directional flow (ES-FR 7.2 bcm/y and FR-ES 5.6 bcm/y). MidCat promoters TIGF (France) and Enagas (Spain) decided to build a fully regulated interconnector on a corporate financing basis involving a total investment volume of 1,550 million Euros. The connection consists of a 600 km pipeline in France and 200 km in Spain which results in an investment volume for TIGF of 1,300 million Euros and 250 million Euros for Enagas.

The project development and investment decision were conditioned by two main factors: the open season process and the agreement between the Spanish and French regulator on the cost/benefit allocation. The economic test via an open season procedure caused delays in the process as well as the lengthy regulatory negotiations. The France-Spain 2015 open season, involving four operators from 2 countries on 6 interconnection points, showed a lack of interest by shippers to commit to long-term capacity. The cost allocation process faced a number of difficulties linked to the cost allocation, including differences in the accreditation, recovery and valuation of costs and the tariff setting.

The open season failed to reflect the wider socio-economic benefits of the MidCat pipeline for the development of the North-South Gas Corridor in Western Europe. The benefits of market integration, increased competition in Southern France, the optimised use of developed Iberian LNG infrastructure and pipelines from North-Africa as well as greater security of supply for the continent were not taken into account by the market participants.

MidCat was also supported by co-financing totalling 175 765 000 million Euros from the European Energy Programme for Recovery.

2.2. Slovakia-Hungary Interconnector – North South Gas Corridor in Eastern Europe

The 115 km natural gas interconnector between Slovakia and Hungary is to connect Velké Zlievce (Slovakia) and Vecsés (Hungary) with an annual capacity of 5 bcm/y. The project promoters Eustream and FGSZ decided for a fully regulated interconnector with a total investment volume of 192 million

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111 Italy's ENEL Distribuzione successfully introduced smart meters to reduce unpaid electricity consumption.

112 Ahmad Faruqui et al., 2009

Euros. The interconnector consists of a 21 km pipeline in Slovakia and 94 km pipeline in Hungary with bi-directional capacity.

Two open seasons were organised without yielding sufficient market demand through long-term capacity commitments. The first open season did not reach the threshold of 10mcm/d, but only 5mcm/d (while total capacity is 14mcm/d). The open season indicated only limited capacity booking for short-term contracts (1/3 of capacities for the first 5 years) despite the interest from the Slovakian side.

Key difficulties for the project relate to the cost allocation (based on the length of the pipeline in each of the country) which is not sufficiently taking into account the wider benefits. The interconnector brings significant EU wide benefits for market integration in Central Eastern Europe on the North-South axis, but also benefits to the Hungarian gas market thanks to bringing in new sources of gas. The project enhances security of supply of Slovakia by providing access to Hungarian gas storages in case of emergency.

The project received support from the European Energy Programme for Recovery totalling 30 million Euros.

ANNEX 12
EXTERNALITIES FACED BY ENERGY INFRASTRUCTURE PROJECTS

- Regional or Union-wide **integration of shared electricity or gas resources**, like large-scale renewables or gas from new sources or an integrated offshore electricity grid: The benefits provided have a global public good character, which is not sufficiently reflected in the revenues individual operators can earn from the corresponding investments.
- Use of **innovative technologies:** Projects can involve technological and operational challenges and other "first of their kind" and first-mover risks and uncertainties. While the investment costs incurred fall upon the project promoter in the short term, the benefits provided in terms of technological and operational progress as well as the system benefits and future cost savings for a region or the EU as a whole only materialise in the medium to long term[113]. Examples include high voltage direct current (HVDC) electricity lines, both on- and offshore, or smart grid developments, but also innovative large-scale electricity storage. Such projects are currently not covered under the public funding available for research, development and deployment, notably at EU level (cf. the 7th Framework Programme and the Strategic Energy Technologies Plan). Being industrial-scale applications; they are supposed to be paid for by tariffs. In the current regulatory environment, such innovative projects might be shelved and replaced by suboptimal standard solutions, for which the risks and revenues are better known.
- Regional or Union-wide **security of supply** provided e.g. through increased capacity of the electricity or gas transmission network towards isolated or semi-isolated systems. Project examples include the Poland-Lithuania electricity interconnectors, the Estonia-Finland gas pipeline or the projected common LNG terminal in the Baltic region aiming at ending their isolation, but also many gas storage and reverse flow projects in Central Eastern Europe. Such projects can be difficult to realise, as regulators are reluctant to take on costs for a security of supply benefit, which might only realise very rarely if at all – as is the case for the Hungarian-Slovakia interconnector.
- **Reduction of electricity loop flows** through transit countries by reinforcing networks in the transit countries or increasing transfer capacities on the direct route between a generator and a consumer: As these flows are physical, not commercial, there is not necessarily a natural incentive for investments in form of achieving increased cross-border trading capacity. This would typically be the case for new transmission lines in Germany to transport wind energy generated in the North towards the South of the country and reducing flows through the electricity networks of Poland, the Czech Republic, Slovakia, Hungary or Austria to the East or the Netherlands, Belgium and France to the West. Loop flows occur also in other regions such as Slovenia following commercial flows from France to Italy.
- **Increased market competition** provided by adding new or additional electricity or gas interconnection capacities and thereby creating the possibility for potential new entrants to access markets, lowering market concentration and possibly contributing to price convergence: Market incumbents often resist the implementation of such projects, which makes them difficult to realise.
- **Long-term optimal capacity (or "advanced capacity")** provided by "oversizing" gas pipelines or offshore electricity hubs and other shared network components compared to the short-term demand they cover: Infrastructure in place creates new opportunities, stimulates demand and enables increased competition. According to Rious et al. (2010), proactive behaviour of a TSO that anticipates connection of new generators with short construction durations compared to the time needed to reinforce the network is the socially optimal solution. However, due to the risk of sunk costs in case the generator never realises its investment in electricity or the supplier never

[113] Cf. "new wave projects" as defined by Glachant and Kalfallah, 2011

offers the quantities anticipated in gas, the costs for such advanced capacity provision are generally not accepted by national regulators, making such projects impossible to realise.

- Internalisation of **environmental externalities:** The 2006 Stern Review on the Economics of Climate Change[114] report has described climate change as biggest market failure or externality currently existing, mainly due to its supra-regional nature and its long time horizon. Energy-related emissions constitute around 80% of total EU GHG emissions. New or improved energy infrastructures are necessary to enable the widespread provision of low carbon energy supplies, for which demand and supply and costs and benefits will be unevenly distributed across EU Member States[115]. In addition, by enhancing the climate resilience of infrastructures of common interest, possible external costs of power outages or network disruptions can be reduced[116].

114 http://webarchive.nationalarchives.gov.uk/+/http://www.hm-treasury.gov.uk/sternreview_index.htm

115 A first assessment of possible impacts from decarbonisation of the electricity sector by 2050 on the European electricity network and in particular interconnectors and net transfer capacities between Member States will be published in the Impact Assessment for the Energy Roadmap 2050.

116 External costs of transmission system disruptions can exceed several times the impacts to the transmission system itself. As investments in reducing the risk of transmission reduction are only made commensurate to the expected damage costs incurred by the system's operator, the investment level can be (socially) sub-optimal.

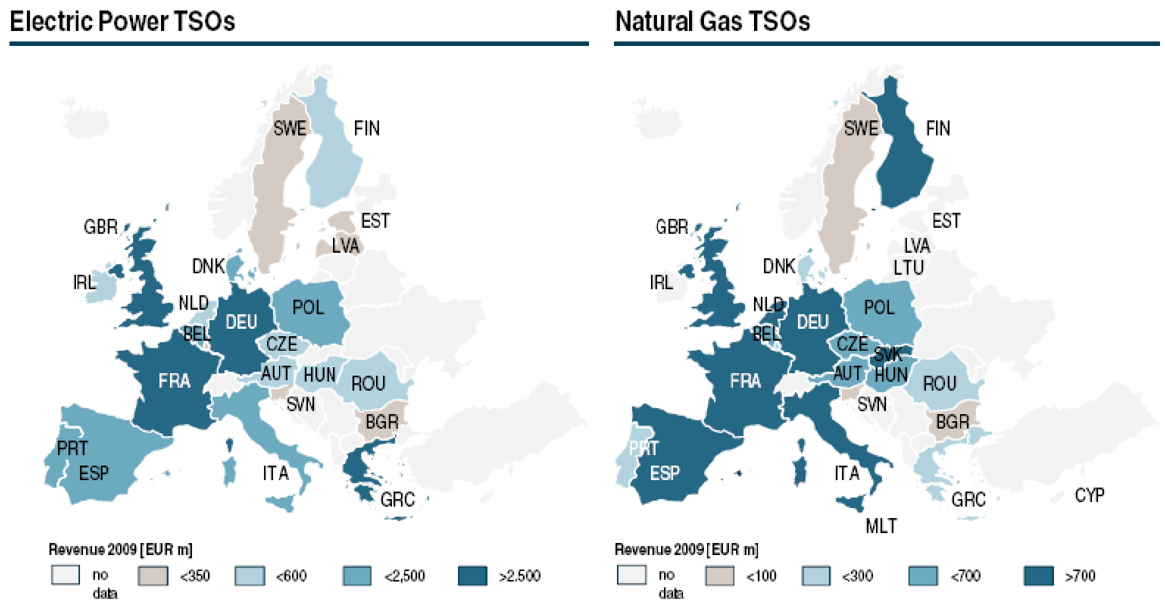
ANNEX 13
FINANCING CONTEXT FOR GAS AND ELECTRICITY INFRASTRUCTURE

Table 11: Corporate versus project finance in energy infrastructures

	Corporate Finance	Project Finance
Approach	• **Financing on the group level** of the TSO for a portfolio of projects, not on an individual project basis • **Projects are taken on the balance sheet** of the TSO	• **Financing on a project-specific level** • **Projects are not directly on the balance sheet of specific TSOs** but in a separate project company
Financing costs	• **Advantageous company specific conditions** on the group level can be passed on to specific projects	• **Higher financing costs** as risk for investors/lenders is higher on a project-specific level than for a whole project portfolio. This is especially the case during the preparation and construction phase of a project.
Application	• **All domestic projects and a large share of interconnectors are corporate financed** based on the interviews	• **Project Finance is applied for specific projects** – Merchant interconnectors that are run and structured on a commercial basis (usually high return expectations from congestion rents that match the higher risks) – Specific regulated interconnectors that are set-up in a joint venture company of related TSOs – Specific natural gas storage/LNG projects

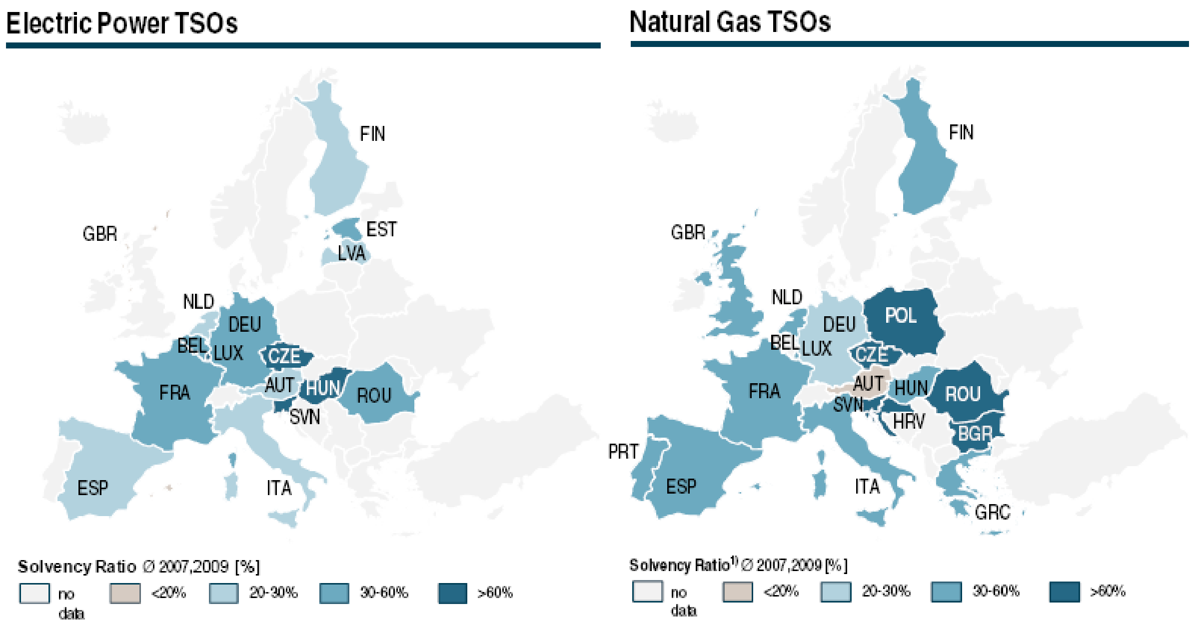
Source: Roland Berger

Figure 13: Revenue and size of EU TSOs (based on 2009 revenues in EUR m)



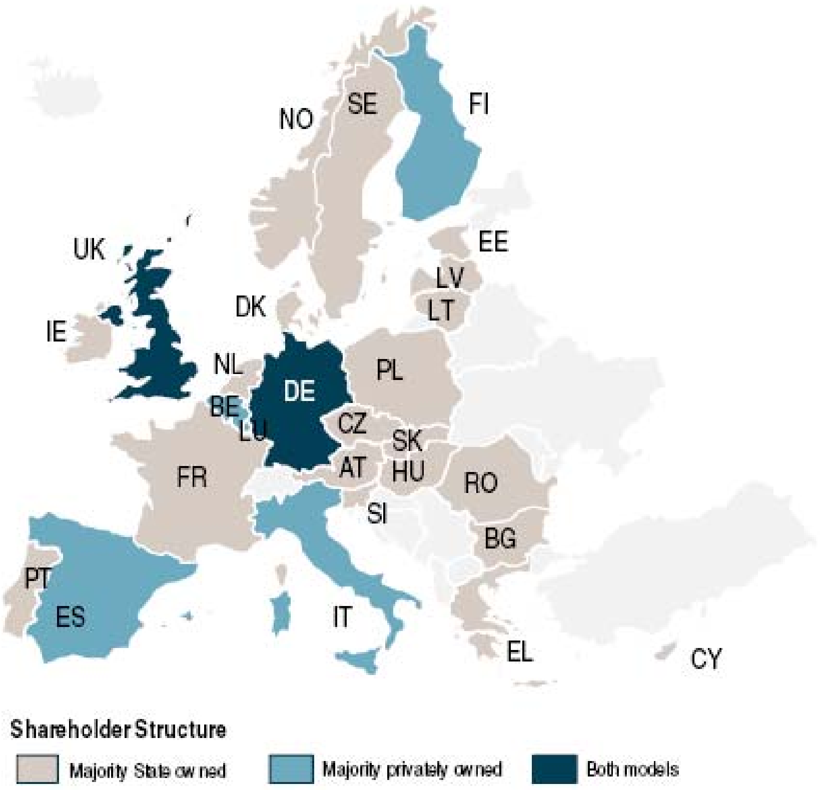
Source: Roland Berger

Figure 14: Financial standing of EU TSOs (solvency ratio in %, 2007/2009 average)



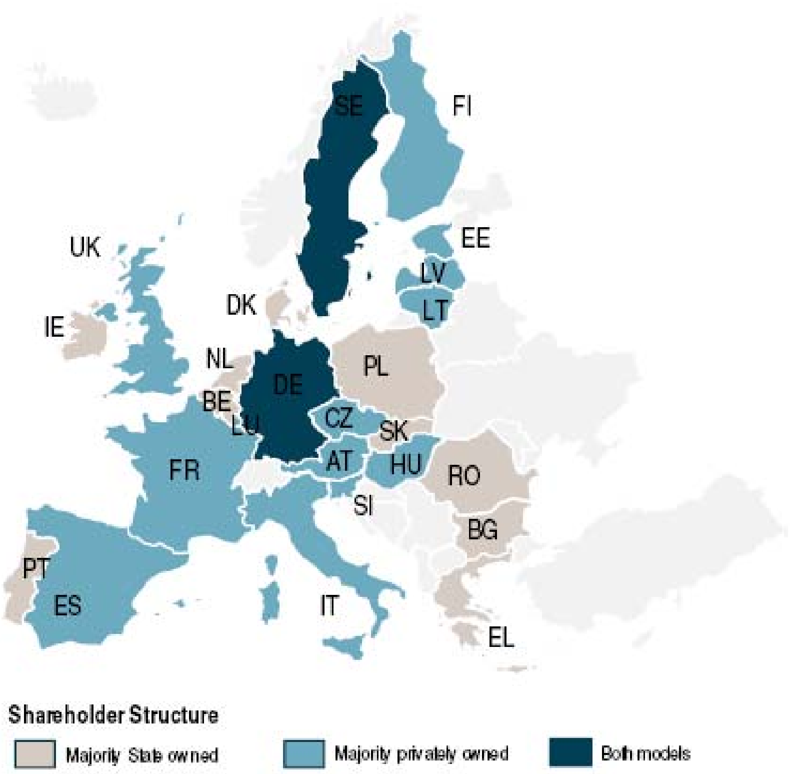
Source: Roland Berger

Figure 15: Ownership structure for EU TSOs in electricity



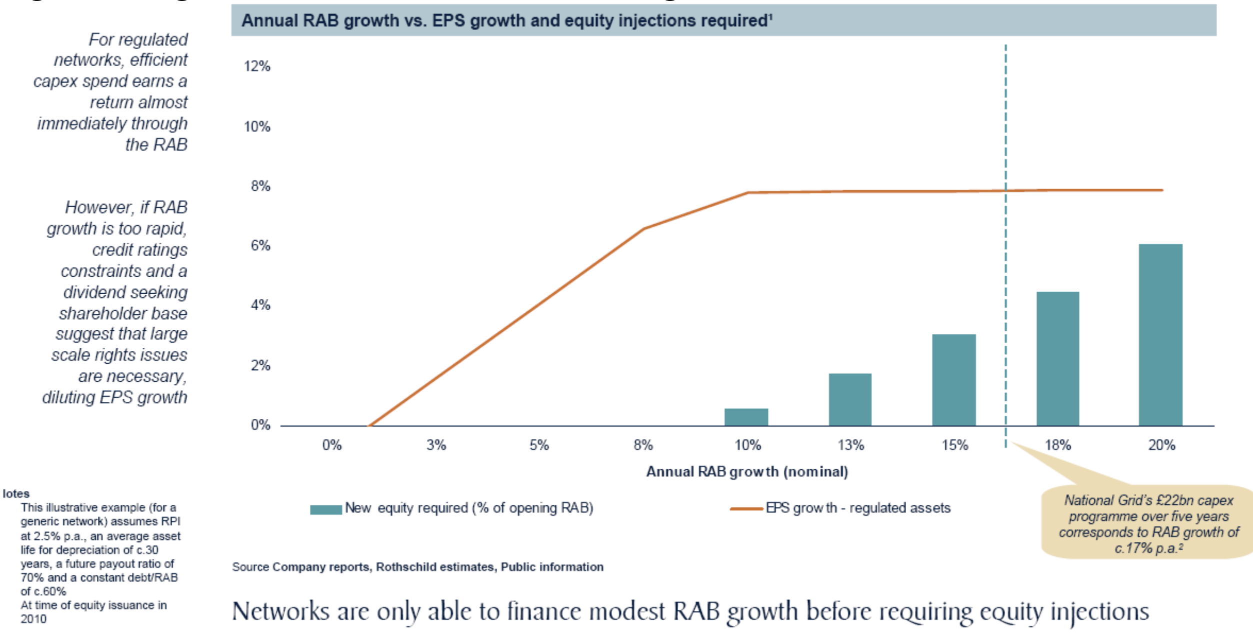
Source: Roland Berger

Figure 16: Ownership structure for EU TSOs in gas



Source: Roland Berger

Figure 17: Regulated Asset Base increase and funding constraints for EU TSOs



Source: Rothschild, Presentation "Financing issues for European energy infrastructure", 10 May 2011

ANNEX 14
THE CURRENT REGULATORY FRAMEWORK FOR INFRASTRUCTURE DELIVERY

The 2010 impact assessment already presented the new regulatory framework of the Third Internal Energy Market Package (3rd IEMP)[117], applicable as of 3 March 2011, and the regulation on security of gas supply[118] in terms of infrastructure development across borders, which will facilitate the implementation of grid investments in electricity and gas. Measures provided for by this framework would be implemented under the baseline scenario.

1. The third internal energy market package

The 3rd IEMP places the obligation on TSOs to operate, maintain and develop secure, reliable and efficient transmission. The unbundling rules will provide further incentives for TSOs to operate their networks efficiently and to expand them as necessary. As described in the 2010 impact assessment, it has become clear that the ten-year network development plans to be developed under this framework will not, in the short to medium term, be able to clearly prioritise among their projects to select those, which provide the highest European added value in view of implementing the infrastructure priorities endorsed by the European Council.

Internal market legislation also provides a legal basis for implementing network tariffs, which ensure the secure and efficient operation of the network. NRAs have the obligation to provide for a tariff framework, which allows for investment to take place to maintain adequate network operation. Article 37(8) of Directive 2009/72/EC and Article 41(8) of Directive 2009/73/EC in particular stipulate that NRAs *"in fixing (…) tariffs (…) shall ensure that transmission and distribution system operators are granted appropriate incentive, over the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities".*

The 3rd IEMP more specifically obliges TSOs to build sufficient cross-border capacity to integrate the European transmission infrastructure. Article 16 of Regulation 714/2009 provides that revenues, which TSOs collect from marketing scarce cross-border capacities, i.e. congestion revenues, shall be primarily used for either guaranteeing the availability of the allocated capacity or investing in new interconnectors before serving for reducing network tariffs. The table below shows past electricity congestion revenues earned by ENTSO-E members in the period 2006-2010.

Table 12: Electricity congestion revenues 2006-2009 (in EUR m)

TSO	Country		2006	2007	2008	2009	2010	Variation first data year to 2010 (%)
APG	Austria	AT	26,25	44,46	63,20	49,45	32,54	24%
Elia	Belgium	BE	58,13	40,33	29,24	28,61	23,73	-59%
NOS BiH	Bosnia Herzegovina	BA	N/A	N/A	0,38	0,20	0,78	105%
ESO	Bulgaria	BG	0,00	2,32	23,60	19,13	19,55	742%
HEP-OPS	Croatia	HR	N/A	N/A	5,86	4,91	12,87	120%
CEPS	Czech Republic	CZ	101,96	59,78	34,62	26,18	18,52	-82%
Energinet	Denmark	DK	79,46	95,15	129,89	58,25	90,78	14%
Elering OU	Estonia	EE	0,00	0,00	0,00	0,00	0,22	N/A
Fingrid	Finland	FI	11,87	22,60	23,20	4,86	9,05	-24%

[117] Including Directives 2009/72 for electricity and 73 for gas and Regulations 713/2009 on ACER, 714 electricity and 715 gas

[118] Regulation No 994/2010.

TSO	Country		2006	2007	2008	2009	2010	Variation first data year to 2010 (%)
RTE	France	FR	342,00	376,50	380,60	256,98	260,37	-24%
TSO of EnBW+Amprion+50 Hertz+Tennet+TIWAG Netz+VKW Netz	Germany	DE	316,30	220,56	222,46	167,90	141,00	-55%
National Grid	Great Britain	GB	N/A	N/A	106,00	66,10	61,60	-42%
HTSO	Greece	GR	22,00	5,06	31,32	35,47	29,29	33%
Mavir	Hungary	HU	29,44	47,09	76,44	48,98	15,38	-48%
EirGrid	Ireland	IE	6,20	13,14	0,00	0,00	0,00	-100%
Terna	Italia	IT	89,82	333,82	294,61	187,83	211,65	136%
AS Augstsprieguma tikls	Latvia	LV	0,00	0,00	0,00	0,00	0,22	N/A
MEPSO	FYROM	MK	N/A	N/A	1,16	6,71	4,40	279%
AD Prenos	Montenegro	ME	N/A	N/A	1,77	3,67	4,32	144%
Tennet	Netherlands	NL	107,63	53,96	105,90	59,00	34,00	-68%
Statnett	Norway	NO	17,96	31,90	112,90	45,60	112,70	527%
PSE Operator	Poland	PL	70,16	40,92	28,08	13,43	6,43	-91%
REN	Portugal	PT	0,00	23,22	32,30	5,52	6,07	#DIV/0!
Transelectrica	Romania	RO	10,68	17,69	36,66	22,09	6,92	-35%
EMS	Serbia	RS	N/A	N/A	29,04	18,85	17,22	-41%
SEPS	Slovak Republic	SK	22,48	44,39	36,17	27,90	5,10	-77%
ELES	Slovenia	SI	3,12	25,91	32,55	32,95	28,51	814%
REE	Spain	ES	25,79	61,78	77,95	41,58	33,28	29%
Svenska Krafnät	Sweden	SE	35,40	67,83	85,30	28,17	54,98	55%
Swissgrid	Switzerland	CH	35,29	40,05	78,10	59,37	62,02	76%
		Total	**1.411,93**	**1.668,47**	**2.079,31**	**1.319,71**	**1.303,49**	**-8%**

Note: Countries with no congestion rents are not represented.

Source: data from national TSOs collated by ENTSO-E, Commission analysis (last column), 2011

2. The exemption regime

In cases where "the level of risk attached to the investment [is] such that the investment would not take place unless an exemption was granted", EU internal market legislation foresees the possibility for new cross-border infrastructure projects to be exempted by NRAs from third party access (the owner of a grid is obliged to allow any suppliers non-discriminatory access to its grid to supply customers), regulated tariffs, unbundling rules and (for electricity) rules on the use of congestion rents[119]. In cases where the NRAs concerned cannot agree on a decision within a given period of time ACER is obliged to take their place and issue a decision. The procedures also foresee that the Commission can ask the NRAs or ACER to amend or withdraw the exemption granted.

Such exemptions have e.g. been granted to large pan-European gas import pipelines or LNG infrastructures and have comforted investors whose projects are either very capital intensive and/or carry exceptional risks, which could not be accommodated within the standard regulatory framework.

However, exemptions should only be granted in cases where the risks related to the investment are such that it is not viable without an exemption and when the new infrastructure will enhance competition. As demonstrated in Pelkmans and Kapff (2010), while contributing to cross-border

[119] Article 36 Directive 2009/73/EC (gas) and Article 17 Regulation (EC) No 714/2009: The exemption regime applies to all direct current electricity lines and certain alternating current lines and to major new gas infrastructure, i.e. interconnectors, LNG and storage facilities.

network development, exempted (merchant) interconnector investments financed through congestion rents alone yield suboptimal results in terms of socially desirable levels of interconnection capacity. In addition, broad exemptions from the regulated regime without additional conditions may weaken competition, hinder reinvestment of profits in grid reinforcements and undermine the application of a harmonized regulatory framework across the EU. To this end, the Commission has regularly asked for substantial amendments of national exemption decisions with the view to alleviate potential competition concerns and support network investment.

Under the baseline scenario, the Commission would therefore continue to push national regulators to establish appropriate incentives through regulated tariffs and to grant exemptions only where justified and with regulatory conditions that ensure third party access and support the development of infrastructures. Such an approach is likely to deliver the types of projects targeted under the third package, i.e. gas and electricity projects enhancing competition and security of supply. The exemption regime does not specifically address electricity projects aiming at the integration of renewables or greater system reliability. Nor does it solve the problem faced by projects with asymmetric cost and benefit allocation, as any exemption is subject to a national regulatory authority assessing the request made by an operator. It can hence be concluded that the exemption regime would allow certain riskier investments to be delivered, without addressing the underlying problems related to cost allocation and broader investment incentives.

3. The target model

The Commission has worked over the last few years with regulators, TSOs and all other stakeholders to develop an electricity target model based on market coupling for linking electricity markets. For gas a target model is currently being developed. The process of implementing the 3rd IEMP by developing guidelines, framework guidelines and network codes to reach the necessary level of harmonisation has already been started. Currently these guidelines, framework guidelines and network codes are being prepared for electricity and gas to achieve common and coordinated congestion management[120] and capacity allocation procedures on all interconnectors. For the years 2012 and onwards, the priorities for gas will notably include framework guidelines or guidelines on tariffs. The Commission could also propose additional guidelines on investment incentives to TSOs in electricity. All these new rules shall be in place by 2014.

Aligning procedures for trading on interconnectors will help to align national markets and provide more harmonised signals across the EU for investment in new interconnection capacity. These regulatory efforts will considerably improve investment signals, including for cross-border infrastructure, once they are fully operational.

4. The regulation on security of gas supply

The regulation on security of gas supply for the first time proposes two clear and binding infrastructure standards:

- Member States[121] shall ensure that gas demand can be met even at the loss of their largest infrastructure (N-1 criterium). They have until 2014 to comply with this rule. Preliminary calculations of compliance with the n-1 standard with and without projects to be financed under the EEPR can be found in the figure and the table below;
- TSOs have to install physical reverse flows at all cross-border interconnections between Member States by end 2013, where they are beneficial for security of supply[122].

[120] It should be noted that the measures proposed by the Commission on congestion management for gas only address contractual congestion at interconnection points and not physical congestion; nor do they address problems faced in the absence of interconnections (see draft impact assessment accompanying the Commission guidelines on congestion management procedures and replacing existing guidelines annexed to Regulation (EC) 715/2009).

[121] Except Luxemburg, Slovenia, and Sweden.

[122] Exemptions are possible and Member States can opt for a regional approach to fulfill these standards.

Figure 18: Compliance with the N-1 standard (2009)

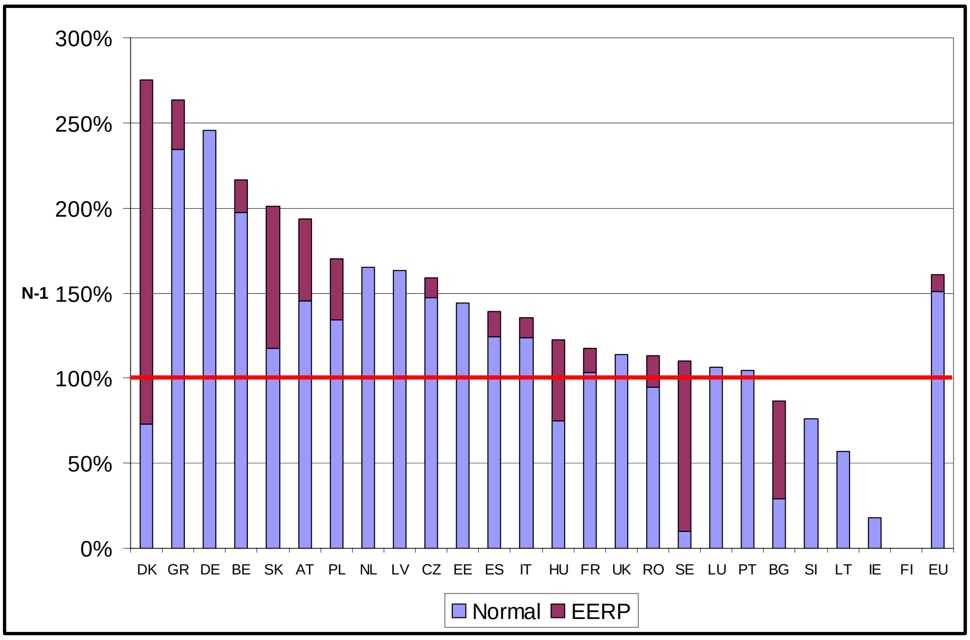


Table 7: Compliance with the N-1 standard (2009)

Mcm/day	Production withdrawal capacity	Maximal Consumption*	Storage Withdrawal capacity	LNG send-out capacity	Incoming Pipeline Capacity	Single Largest Infrastructure	N-1
AT	12,16	49,41	48,00	0,00	137,52	125,94	145%
BE	0,00	139,20	22,80	24,70	321,61	94,43	197%
BG	0,30	15,60	4,20	0,00	72,00	72,00	**29%**
CY	0,00	0,00	0,00	0,00	0,00	0,00	-
CZ	0,30	67,60	55,01	0,00	185,98	141,94	147%
DE	45,00	400,00	463,32	0,00	579,44	105,96	245%
DK	29,90	25,70	18,80	0,00	0,00	29,90	**73%**
EE	0,00	4,30	0,00	0,00	22,99	16,80	144%
ES	0,00	160,20	10,54	160,90	67,01	39,70	124%
FI	0,00	1,00	0,00	0,00	20,68	20,68	**0%**
FR	2,40	370,00	231,00	42,44	156,28	50,00	103%
GR	0,00	14,00	0,00	13,69	38,36	19,20	235%
HU	9,00	92,50	47,50	0,00	58,04	39,80	**81%**
IE	1,00	20,30	2,60	0,00	30,00	30,00	**18%**
IT	24,00	425,00	295,85	35,00	284,80	114,60	124%
LT	0,00	16,00	0,00	0,00	39,11	30,00	**57%**
LU	0,00	5,98	0,00	0,00	11,30	4,93	107%
LV	0,00	9,00	14,69	0,00	24,64	24,64	163%
MT	0,00	0,00	0,00	0,00	0,00	0,00	-
NL	440,00	235,00	153,02	0,00	95,62	300,00	165%
PL	6,48	59,71	34,20	0,00	147,56	108,00	134%
PT	0,00	19,30	7,00	14,20	13,21	14,20	105%
RO	34,30	75,00	25,80	0,00	113,00	102,00	**95%**
SE	0,00	6,00	0,60	0,00	8,49	8,49	**10%**
SI	0,00	5,80	0,00	0,00	14,53	10,13	**76%**
SK	0,30	29,90	34,87	0,00	301,00	301,00	118%
UK	231,00	536,00	126,57	84,56	241,34	73,70	114%

(1-in-20 winter case)

Source: SEC(2009)979; IHS and Gas Coordination Group

According to Regulation 994/2010 and the Commission preliminary analysis (Annex X), Bulgaria, Lithuania, Ireland, Finland, Hungary, Denmark, Romania, Sweden and Slovenia did not fulfill the N-1 rule in 2009. Over the last years, the EEPR programme accelerated a number of gas infrastructure projects that will help those countries to meet the N-1 standard by the deadline. However, it is expected that further measures will be needed for Bulgaria, Lithuania, Finland, and Ireland. The Regulation allows Sweden, Slovenia and Luxembourg to have a longer timeframe to meet N-1. The Regulation allows the Member States flexibility in meeting the N-1 rule - through demand-side measures or regional N-1 rule. While the N-1 standard ensures the security of gas supply mainly at national and partially at regional level, it does not automatically ensure the infrastructure needed to enhance market integration or competition in a wider European gas market.[123]

5. Other regulatory measures

Furthermore, tariff setting would remain the exclusive competence of NRAs. Investments in cross-border infrastructure would continue to be subject to the same rules, which also govern domestic infrastructure investments. This framework will ensure that cross-border investments go ahead, with TSOs sharing costs according to individual agreements (usually covering all investment cost in their own service area) with congestion revenues often split on a 50:50 basis, although other ratios have been seen as well[124].

Projects with asymmetric benefits and costs across border however will continue to suffer from the absence of a transparent cost-benefit analysis[125] and an effective cost allocation mechanism covering all investments beyond those covered under the security of gas supply regulation with regard to benefits oriented cost allocation[126]. Even if multilateral cost sharing agreements could be developed, which would be burdensome and on a case-by-case basis only, this would significantly hamper the development of infrastructures of common interest.

In gas, the open season procedure to assess market demand would continue to be used, although, when designed along national rules, it will tend to shield incumbents against competition and fail to deliver in regions which lack a competitive gas market structure. Today, open seasons are governed by voluntary CEER guidelines on best practices, which are currently under revision. The CEER public consultation carried out in 2010 concluded that the open season procedures lack transparency and do not provide for sufficient efficiency in getting binding commitments[127].

In electricity, the inter-transmission system operator compensation (ITC) mechanism, which compensates TSOs for the cost of hosting transit flows caused by other Member States, would continue to be the only existing pan-European cost allocation mechanism[128]. Several limitations to this mechanism have however been identified by operators and regulators. First, the ITC is not designed for incentivising new large scale investments in the transmission network, which are needed to meet the infrastructure needs identified. Second, the corresponding fund is capped at 100 million euros, constraining its ability for significant redistribution[129]. Third, the ITC only serves to transfer funds from import or export countries to transit countries, not for more complex constellations.

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123 It will become fully clear how many Member States require additional investment to fulfill N-1 in December 2011 when the risk assessments under Article 9 of the Regulation are presented by the Competent Authorities.

124 The Ireland-UK electricity interconnector will be fully paid by the Irish TSO Eirgrid. France and Luxemburg have also agreed on an asymmetric allocation of costs for new gas interconnection capacities at their border.

125 See Proost et al., 2010, on the merits of cost-benefit analysis for projects of European relevance in the transport sector.

126 Article 6(8) of the security of gas supply regulation already allows for cost-benefit allocations in case of reverse flow investments.

127 CEER position paper on cost allocation: CEER consulted in 2009 on the revision of the ERGEG GGP on Open Season procedures (GGPOS). The ERGEG Guidelines for Good Practice on Open Season Procedures (GGPOS), 21 May 2007.

128 Regulation 714/2009, article 13 and Commission Regulation 838/2010

129 Based on load data for 2009 and costs of losses for 2011, the main contributors to this fund are Italy, Norway, Great Britain, France and the Czech Republic, while the main beneficiaries are Germany, Switzerland, Sweden and Austria (Source: ENTSO-E).

6. Permit granting framework

Permit granting for energy infrastructure projects is a Member State competence, with varying rules and practices across the EU. Only a few countries have so far passed legislation to address problems related to administrative permit granting procedures and resulting delays. Reforms to introduce "one-stop shops" and time limits were recently passed in Ireland, the Netherlands and the United Kingdom, resulting in significant reductions in the duration of the process[130]. In July 2011, the German government passed a law for the acceleration of network expansion, which also foresees the creation of a "one-stop shop" for planning and permit granting of important electricity infrastructures, to be managed by the national regulatory authority. The latter would also be in charge of fixing time limits for each project submitted to the one-stop shop. As of today, time limits for the entire statutory process of granting permits exist in 5 Member States (Austria, Czech Republic, Greece, Ireland, Italy), while 10 Member States (Austria, Germany, Greece, Ireland, Italy, the Netherlands, Poland, Romania, Spain and the United Kingdom) have fast-track schemes for certain types of infrastructure (see details in Annex 7).

It is expected that such legislation will deliver improvements in the Member States where it is implemented, though leaving untouched problems faced in the remaining Member States.

[130] Results from a consultation carried out amongst members of ENTSO-E in March 2011.

ANNEX 15
PAST AND FUTURE INFRASTRUCTURE DEVELOPMENT IN THE EU

Table 13: New EU cross-border electricity projects realised between 2000 and 2011

Project	Sub-section / routing / specification	Estimated total cost (M€)	Indicative start of operations	EU grants 1995-2010 (M€, TEN-E, if not otherwise stated)
Vigy (FR) - Uchtelfangen (DE) line		N/A	2002	0,23
Western Pyrenean interconnection FR - ES	Cantegrit - Mougerre (220kV) - (Arkale, ES)	N/A	2002	
Kardia (GR) – Elbasan (AL) line		N/A	2002	
New connections for the Mediterranean Electricity Ring	Ipiros (GR) - Puglia (IT)	N/A	2002	
North-East PT - North-West ES line	Lindoso II (PT) - Cartelle (ES)	N/A	2004	
Sines (PT) - Alqueva (PT) - Balboa (ES) line		39	2004	0,68
IT - CH line	San Fiorano (IT) - Robbia (CH)	77	2005	0,25
Avelin (FR) - Avelgem (BE) line		21,5	2005	1,01
Reinforcement of the connections DK - SE		35	2006	
Submarine cable to link FI and EE	Estlink cable	110	2006	0,67
Meliti (GR) - Bitola (Former Yugoslav Republic Of Macedonia) line		5 (for the GR side)	2007	0,13
Eemshaven (NL) - Feda (NO) link	NorNed cable	565	2008	8,72
Békéscsaba (HU) - Oradea (RO)	Békéscsaba (HU) - Nadab (RO) - Arad (HU)	18,5	2008	2,02
Philippi (GR) - Hamidabad (TR) line		70	2008	0,55
Dürnrohr (AT) - Slavetice (CZ) line		9	2008	
New connections between GR, AL, BG and FYROM	Stip (FYROM) – C. Mogila (BG)	50	2009	
New connections for the Mediterranean Electricity Ring		55	2009	
Pécs (HU) - Ernestinovo (HR)		43,6	2010	2,24
New connection mid SE - mid NO		66	2010	0,06
Moulaine (FR) - Aubange (BE) line		11 (FR)	2010	0,50

South PT - South-West ES	Portimão (PT) - Tavira (PT) - P. Gusman (ES) - Guillena (ES) line and Tavira facilities	90,9	2011	50 (EEPR)
Connection between IE and Northern Ireland (UK)	400 kV North South Interconnector (Tyrone – Cavan)	N/A	2011	0,60
Valdigem (PT) - Douro Internacional (PT) - Aldeadavila (ES) line and facilities	400 kV Douro interconnection Aldeadávila (ES) - Lagoaça (PT)	88	2011	51,808 (of which 50 EEPR)
Submarine cable South-Eastern UK - central NL	BritNed cable (Isle of Grain in Kent (UK) - Maasvlakte (NL))	600	2011	12,75
Connection north of the Gulf of Bothnia (FI) - SE	Fennoscan cable	300	2011	0,75

Source: ENTSO-E, European Commission DG Energy, 2011

Table 14: Planned transboundary electricity projects (new lines and upgrades) in the 2010 TYNDP for the period 2011-2025

Important disclaimer: This list is a compilation of projects as provided by ENTSO-E members and provided for information purposes only. It does not prejudge any future selection of projects of common interest.

Border	Project characteristics	Connection type	Length of Infrastructure line [km]
AL-ME	New 400kV line Tirana (AL)-Podgorica (ME) with length 157km (128.5km on Albanian side, 76km of which with double circuit and 28.5km on the Montenegrin side).	new lines	157
AL-RS	New 238km 400kV OHL; on 78km the circuit will be installed on the same towers as the Tirana-Podgorica OHL currently in construction (see project 233); the rest will be built as single circuit line.	new lines	238
AT-HU	Installation of the 2nd circuit on the existing interconnection from Wien SO (AT, APG) to the border (both circuits have already been installed on the Hungarian side, one is connected to Györ and the 2nd circuit to Szombathely). Line length: 63km.	new lines	63
AT-IT	New double circuit 400kV interconnection through the pilot tunnel of the planned Brenner Base Tunnel. Total line length: 65km.	new lines	65
AT-IT	The project foresees the reconstruction of the existing 220kV-interconnection line as 380kV-line on an optimized route to minimize the environmental impact.Total length should be in the range of 100-150km.	upgrade of existing lines	125
AT-IT	New 380/220kV substation in AT directly located near the border ; erection of a 24km single circuit 220kV-connection via OHL and underground cable till Graun (IT) and upgrade of the existing line Graun (IT) – Glorenza (IT).	upgrade of existing lines	24
AT-IT	Upgrade of the existing 44km Prati di Vizze (IT) – Steinach (AT) single circuit 110/132kV OHL, currently operated at medium voltage and installing a 110kV/132kV PST in Steinach (AT).	upgrade of existing lines	44
BA-HR	New 400kV interconnection line between existing stations.	new lines	50*
BA-HR	Connection of new generator on existing line 220kV Mraclin (HR) - Prijedor (BA) via a new double circuit OHL. Line length: 12km.	new lines	12
BA-HR	Re-establishment of previously existing 220kV double circuit interconnection Trebinje(BA)-Plat(HR); Total length 10km.	upgrade of existing lines	10
BA-ME	New 400kV transmission line between existing stations. Line length: 70km.	new lines	70
BG-GR	New interconnection line BG-GR by a 130km single circuit 400kV OHL.	new lines	130
BG-RO	New 400kV double circuit OHL to accommodate RES generation. Line	new lines	10

Border	Project characteristics	Connection type	Length of Infrastructure line [km]
	length: 2x10km.		
CH-IT	New 400kV tie line between Italy and Switzerland.	new lines	70*
CZ-AT	Possible increase of interconnection capacity between CEPS and 50Hertz Transmission is under consideration: either a new 400kV tie-line (OHL on new route) or a reinforcement of the existing 400kV tie-line Hradec (CEPS) – Röhrsdorf (50Hertz Transmission).	upgrade of existing lines	120*
CZ-DE	New 400kV single circuit tie-line between new (CZ) substation and existing (DE) substation. Length: 70km.	new lines	70
DE-AT	New 400kV double circuit OHL Isar - St. Peter including new 400kV switchgears Altheim, Simbach and St. Peter and one new 400/230kV transformer in substation Altheim. Line length: 90km.	new lines	90
DE-AT-CH	Construction of new lines, extension of existing ones and erection of 400/220/110kV-substation.	upgrade of existing lines	100*
DE-BE	Connection between Germany and Belgium including new 100km underground cable and extension of existing 380kV-substations.	new lines	100
DE-FR	Change of conductors on the German part of this single circuit 225kV line (9km) and installation of a phase-shifter in Ensdorf (DE) 225kV substation.	upgrade of existing lines	9
DE-NL	New 400kV line double circuit DE-NL interconnection linew. Length: 60km.	new lines	60
DE-PL	This project is the 3rd 400kV double circuit OHL interconnection between Poland (Plewiska) and Germany (Eisenhüttenstadt) with reinforcement of the Polish internal grid. Total length is 252km, 242km of which being in Poland.	new lines	252
DE-PL	This project is the conversion of existing 220kV double circuit line Krajnik (PSE Operator) - Vierraden (50Hertz Transmission) into a 400kV line together with installation of phase shifting transformers in Krajnik (PSE Operator) and Mikułowa (PSE Operator).	upgrade of existing lines	600*
DK-DE	The Kriegers Flak project is the new subsea cable multiterminal connection between Denmark, Sweden and Germany used for both grid connection of offshore wind farms Kriegers Flak and interconnection. Technical features still have to be determined.	new lines	160*
DK-DE	Installation of two PSTs. This project is in the framework of step 2 in the Danish-German agreement to upgrade the Jutland-DE transfer capacity; This step includes also planed strengthening of existing 380kV lines in the grid of TPS and Energinet.dk .	upgrade of existing lines	40*
DK-DE	Step 3 in the Danish-German agreement to upgrade the Jutland-DE transfer capacity. It consists of partially an upgrade of existing 400kV line and partially a new 400kV route in Denmark. In Germany new 400kV line mainly in the trace of a existing 220kV line. The total length of this OHL is 114km.	upgrade of existing lines	114
DK-NL	COBRA: New single circuit HVDC connection between Jutland and the Netherlands via 350km subsea cable; the DC voltage will be up to 450kVand the capacity 600-700MW.	new lines	350
DK-NO	Skagerak 4: 4th HVDC connection between Southern Norway and Western Danmark, built in parallel with the existing 3 HVDC cables; new 700MW including 230km 500kV DC subsea cable.	new lines	230
EE-FI	A new HVDC (450kV) connection will be built between Estonia and Finland. On the Finnish side, a 14km DC overhead line will be built to a new substation Anttila where the converter station will be placed. On the Estonian side, a 11km DC cable line will be built to a existing substation Püssi where the converter station will be placed. Length of marine cable is 140km. Expected capacity: 650MW.	new lines	165
EE-LT	Latvian-Estonian third interconnection will consist of OHL Harku-Sindi-Lihula in Estonian part, OHL Imanta-Tume-Dundaga-Ventspils in Latvian part, and sea cable between cross-border DC ar AC cable. Final interconnection type and final interconnection and transmission line route will be selected in middle of 2010. At present three alternative route variants researched. Final interconnection length, DC voltage and transmission capacity will be selected in feasibility and technical study in the middle of 2010. The connection would be as a new single circuit line mixed (OHL+subsea cable) up to 500kV.	new lines	380*

Border	Project characteristics	Connection type	Length of Infrastructure line [km]
ES-FR	New HVDC (VSC) bipolar interconnection in the Eastern part of the border, via +/- 320kV DC underground cable using existing infrastructures corridors and converters in both ending points. The thermal capacity is expected in the range 2x825-2x1000MW. Total line length: 60km.	new lines	60
ES-FR	New cross-border line - not in the French department "Pyrenees Orientales" nor in the Spanish region of Cataluña.	new lines	60*
ES-PT	New Duero Interconnection 400kVNew 400kV OHL interconnection line Aldeadávila (ES) - Lagoaça (PT) , including new Lagoaça substation (PT). Also associated, the lines Lagoaça-Armamar-Recarei 400kV in PT and the Armamar (PT) 400/220kV substation.On a first phase (2009) a new 400/220kV substation (Lagoaça - PT) will be created with only 220kV level installed, and there will be some rearrangements and reinforcements on the local 220kV network structure. On river crossing a new 220kV double line with separated circuits, firstly Aldeadavila (ES) - Lagoaça (PT) 1 & 2 and changing later to Aldeadavila (ES) - Pocinho (PT) 1 & 2, will substitute the existing two 220kV lines Aldeadavila (ES) – Bemposta (PT) and Aldeadavila (ES)-Pocinho (PT). Total length: 1km (ES)+105km (PT).	new lines	106
ES-PT	New Southern Interconnection New 400kV OHL double-circuit line between Guillena (ES)-Puebla de Guzman (ES) - Tavira (PT) - Portimão (PT), including new Tavira (PT) and P.Guzman (ES) 400kV substations. On the interconnection section P.Guzmán (ES) –Tavira(PT), initially only one circuit will be placed. Total length: 153km (ES)+110km(PT).	new lines	263
ES-PT	New double circuit 400kV OHL between O Boboras (ES) -O Covelo (ES) - Vila Fria (PT) - Vila do Conde (PT) - Recarei (PT), including new 400kV subestations O Covelo (ES), Boboras (ES), Vila Fria (PT) and Vila do Conde (PT). On the section O Covelo (ES) – Vila do Conde (PT), only one circuit will be placed. Total length: 43km (ES)+112km (PT).	new lines	155
FI-SE	A new 500kV HVDC connection will be built in parallel with the existing one between Finland and Sweden. On the Swedish side, a 70km direct current overhead line will be built to a new substation Finnböle where the converter station will be placed. Total length of line: 300km and capacity: 800MW.	new lines	300
FI-SE	Third single circuit 400kV AC OHL between Sweden and Finland. Expected capacity: 1850 MVA.	new lines	100*
FR-BE	to be determined.	new lines	50
FR-BE	Installation of a second circuit on the existing 225kV cross-border OHL.	upgrade of existing lines	30*
FR-CH	Reinforcement of the interconnection in the area of Geneva's lake.	upgrade of existing lines	60*
FR-IT	"Savoie - Piémont" Project : New 190km HVDC (VSC) interconnection FR-IT via underground cable and converter stations at both ends (two poles, each of them with 500MW capacity). The cables will be laid in the security gallery of the Frejus motorway tunnel and possibly also along the existing motorways' right-of-way.	new lines	190
FR-IT	Replacement of conductors (by ACCS) on Albertville (FR) - Montagny (FR) - Cornier (FR) and Albertville (FR) - La Coche (FR) - La Praz (FR) single circuit 400kV OHLs. Overcoming of constraints of Villarodin (FR) - Venaus (IT) - Piossasco (IT) single circuit 400kV OHLs. In addition, change of conductors and operation at 400kV of an existing single circuit OHL between Grande Ile and Albertville (FR) currently operated at lower voltage, and associated works in Albertville (FR) 400kV substation. (Total length of lines: 257km : French side 66+95+41 Italian side 55).	upgrade of existing lines	459
FR-LU	Connection of SOTEL (industrial grid in LU) to RTE network by mixed (underground cable & OHL) single circuit 225kV line. Parts of the new line use existing ones.	new lines	30*
FR-UK	New subsea DC link, between GB and FR, possibly with a capacity of 1000MW (still to be determined).	new lines	90*
GR-IT	Second 500MW HVDC link between Greece and Italy via 316km 400kVDC	new lines	316

Border	Project characteristics	Connection type	Length of Infrastructure line [km]
	subsea cable and converters stations at both ends.		
IE-UK	A new 260km HVDC (380kV DC) underground and subsea connection between Ireland and Britain with 500MW capacity. On the Irish side, a 45km direct current underground cable will be built to the Woodland substation where the VSC converter station will be placed. The link will consist of two identical circuits.	new lines	260
IE-UK	A new 80km single circuit 400kV 1500MVA OHL from a new Moyhill 400/220kV substation in Ireland to a new Turleenan 400/275kV substation in Northern Ireland. This project is an integral part of the new interconnection project Moyhill- Wooodland between Ireland and Northern Ireland.	new lines	80
IE-UK	Strengthening of EHV networks (partial uprate and new) into Donegal and West of Northern Ireland and enhanced links between the two systems.	upgrade of existing lines	50*
IT-AL	500MW single pole HVDC Merchant Line between Italy and Albania via 290km 400kV DC subsea cable and converter staitons at both ends. On the Italian side, the new line will be connected to the existing substation of Brindisi South.	new lines	290
IT-HR	New 1000MW HVDC interconnection line between Italy and Croatia via 280km 500kVDC subsea cable and converters stations at both ending points.	new lines	280
IT-ME	New 1000MW HVDC interconnection line between Italy and Montenegro via 375km 500kV DC subsea cable and converter stations at both ending points.	new lines	375
LT-LV	Upgrade single circuit OHL (943 MVA, 50km).	upgrade of existing lines	50
LT-SE	(NordBalt) A new 300kV HVDC VSC partly subsea and partly undergroud cable between Lithuania and Sweden. (440km).	new lines	440
LU-BE	New interconnection between Creos grid in LU and ELIA grid in BE via a 16km double circuit 225kV underground cable with a capacity of 1000 MVA.	new lines	16
MK-AL	New 200km cross-border single circuit 400kV OHL between existing substations.	new lines	200
n.a.	Installation of an additional transformer + replacement of an existing one (400/110kV and 220/110kV) and shunt reactors in substations, upgrading and decommissioning of substations.	substation ugrade	1
NO-DE	Nord.Link: A new HVDC connection between Southern Norway and Northern Germany. Estimated subsea cable length: 520 - 600km. Capacity: 700 - 1400MW.	new lines	560
NO-FI	New single circuit 400kV OHL (500km, 1850 MVA).	new lines	500
NO-NL	NorNed 2: a 2nd HVDC connection between Norway and The Netherlands via 570km 450kV DC subsea cable with 700 - 1400MW capacity.	new lines	570
NO-SE	"South West link" consisting of three main parts: 1) New 400kV line between Hallsberg and Barkeryd 2) New double HVDC VSC underground cable line between Barkeryd and Hurva 3) New HVDC VSC line between Barkeryd and Tveiten/Norway. The project also include new substations and converter stations in the connection points line double circuit new OHL Hallsberg - Barkeryd 170km, underground VSC Barkeryd - Hurva 250km and VSC Barkeryd - Tveiten with 103km on the Norwegian side. Expected capacity: 1200MW.	new lines	523
NO-SE	A joint Stattnett & Svenska Kraftnat study north - south reinforcement (AC or VSC), expected length: 400 - 500km under study.	upgrade of existing lines	450
NO-UK	A new 1400MW HVDC bipolar installation connecting Western Norway and the UK via 800km subsea cable; DC voltage is to be determined.	new lines	800
PL-LT	Construction of a new 400kV OHL Ełk to PL-LT border. (2x1870 MVA, 108km).	new lines	108
PL-LT	Construction of Back-to-Back convertor station near Alytus 330kV substation. Construction of double circuit 400kV OHL between Alytus and PL-LT border. Construction of 330kV AC line Alytus-Kruonis. Length of	new lines	46

Border	Project characteristics	Connection type	Length of Infrastructure line [km]
	line: 46km.		
PL-UA	Establish existing 750kV interconnection between Poland and Ukraine. Mode of operation on border lines (synchronous/asynchronous) depends on results of future study concerning possibility of synchronous connection of Ukraine and Moldova to continental part of ENTSO-E and bilateral Polish - Ukrainian agreement.	upgrade of existing lines	430*
RO-MO	New 400kV transmission line between existing station in Romania and new substation in Moldavia. Line length: 145km.	new lines	145
RO-TR	New DC link (subsea cable) between existing stations in RO and TR. Line length: 400km.	new lines	400
RS-MK	New 220km 400kV single circuit overhead interconnection between Serbia and FYROM. A new 400/110 substation will be built in Serbia between connection nodes.	new lines	220
RS-MK	A new 400kV OHL releavant to planning investment of 2000MW of TPP in the area of Kosovo and Metohija. Line length: 85km.	new lines	85
RS-RO	New 150km double circuit (single wired at the beginning) 400kV OHL between existing substations.	new lines	150
SI-HU-HR	The existing substation of Cirkovce (SI) will be connected to one circuit of the existing Heviz (HU) -Zerjavinec (HR) double circuit 400kV OHL by erecting a new 80km double circuit 400kV OHL in Slovenia. The project will result in two new cross-border circuits: Heviz (HU) - Cirkovce (SI) and Cirkovce (SI) - Žerjavenec (HR).	new lines	80
SI-IT	New 120km double-circuit 400kV OHL with installation of a PST in Okroglo. The thermal rating will be 1500 MVA per circuit.	new lines	120
SK-AT-HU	SEPS and MAVIR consider a new interconnection between SK and HU (starting from Gabčíkovo substation - SK) and a connection to the existing 400kV tie-line Györ/Szombathely (HU) - Vienna/Sarasdorf (AT) on Hungarian side.	new lines	30*
TU-IT	New 350km 500MW HVDC line between Tunisia and Italy via Sicily with 400kV DC subsea cable and converters stations at both ends.	new lines	350
UK-BE	Nemo project: new DC sea link including 135km of 250kV DC subsea cable with 1000MW capacity.	new lines	135
UK-NL	New 1290MW HVDC bipolar installation including 260km of 450kV DC subsea cable.	new lines	260

* Commission estimation of length

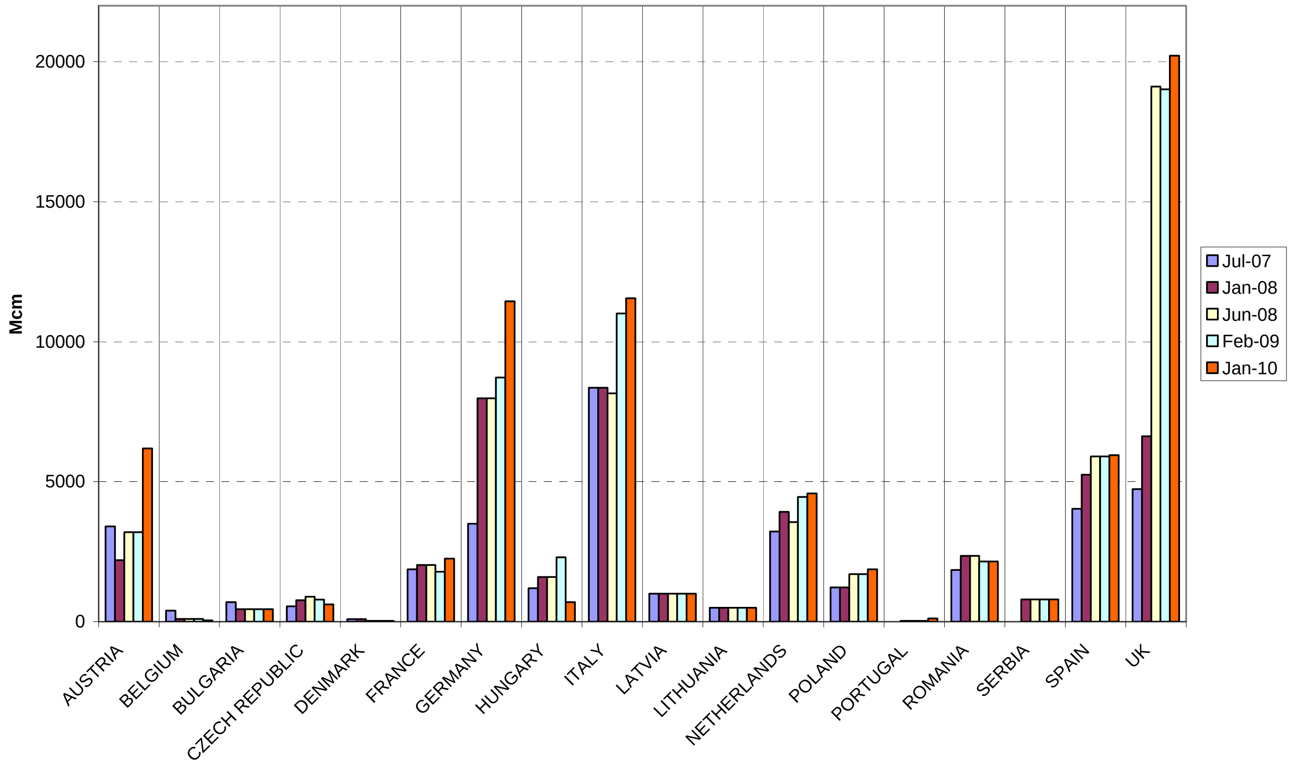
Table 15: New gas infrastructure realised between 2000 and 2011

Inauguration / start of operations	New interconnectors	TEN-E / EEPR support (in Million Euro)
2006	BBL (UK-BE)*	-
2011	OPAL DE-CZ*	-
2011	PL-CZ	14
2010	HU-HR	20
2010	RO-HU	16.6
	New LNG Terminals	
2009	Dragon LNG Terminal*	-
2010	South Hook LNG Terminal*	-
2009	North Adriatic LNG Terminal (Rovigo)*	-
2011	Gate LNG Terminal Rotterdam*	-
2005	Grain LNG Terminal NCG*	-
2010	Fos-Cavau	-
2003	Sines	0.9
2003	Bilbao	-
2006	Sagunto	-
2007	Mugardos	-
	New import pipelines	
March 2011	Medgaz (Algeria-Spain)	2
2011	Nord Stream (Russia-Germany)	-
2006	Langeled (Norway-UK)	-
2005	Greenstream (Libya-Italy)	-
	Storages developed since 2008	*TEN-E support not specified as country approach*
January 2007	AT	
June 2008	AT, DK, FR, DE, IT, ES	
February 2009	AT, DK, FR, DE, IT, ES, UK	
January 2010	AT, BE, CZ, DK, FR, DE, HU, IT, ES, UK	

* Exemption obtained

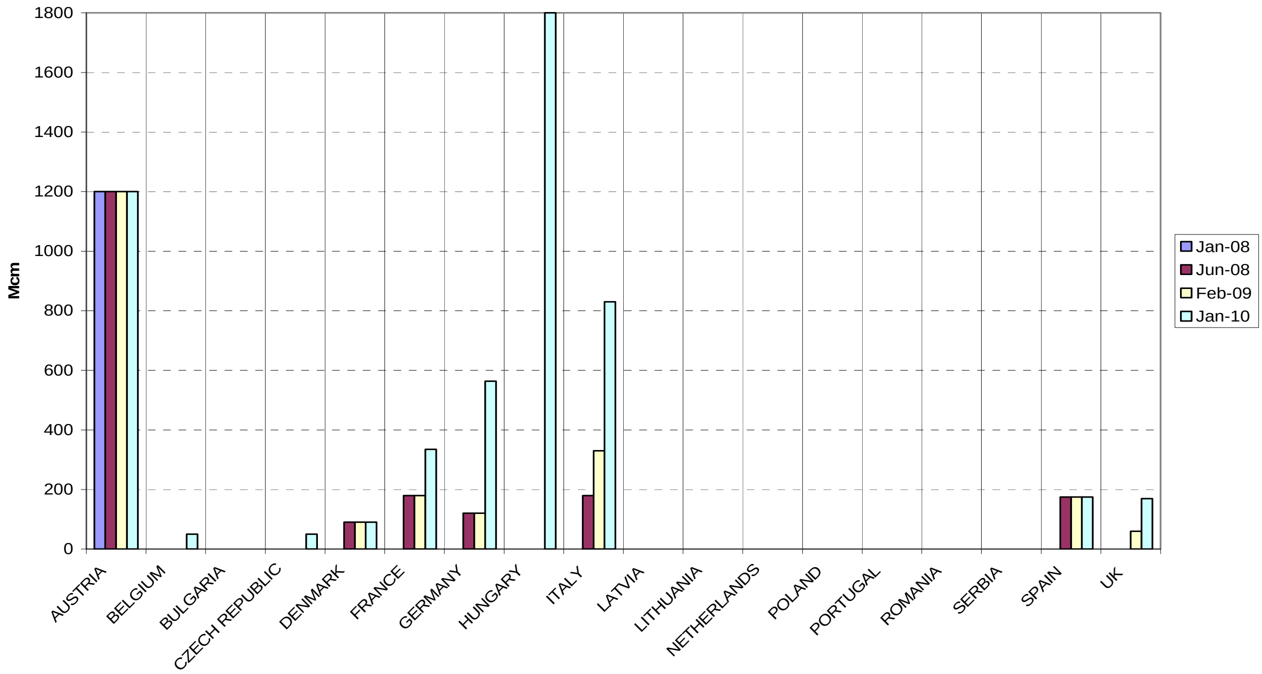
Source: GLE Investment database 2010; GSE Investment database 2008-2010; ENTSOG TYNDP 2011; European Commission DG Energy, 2011.

Figure 19: Gas storage investments in selected Member States between 2007 and 2010



Source: GSE

Figure 20: Gas storages developed in selected Member States since 2008



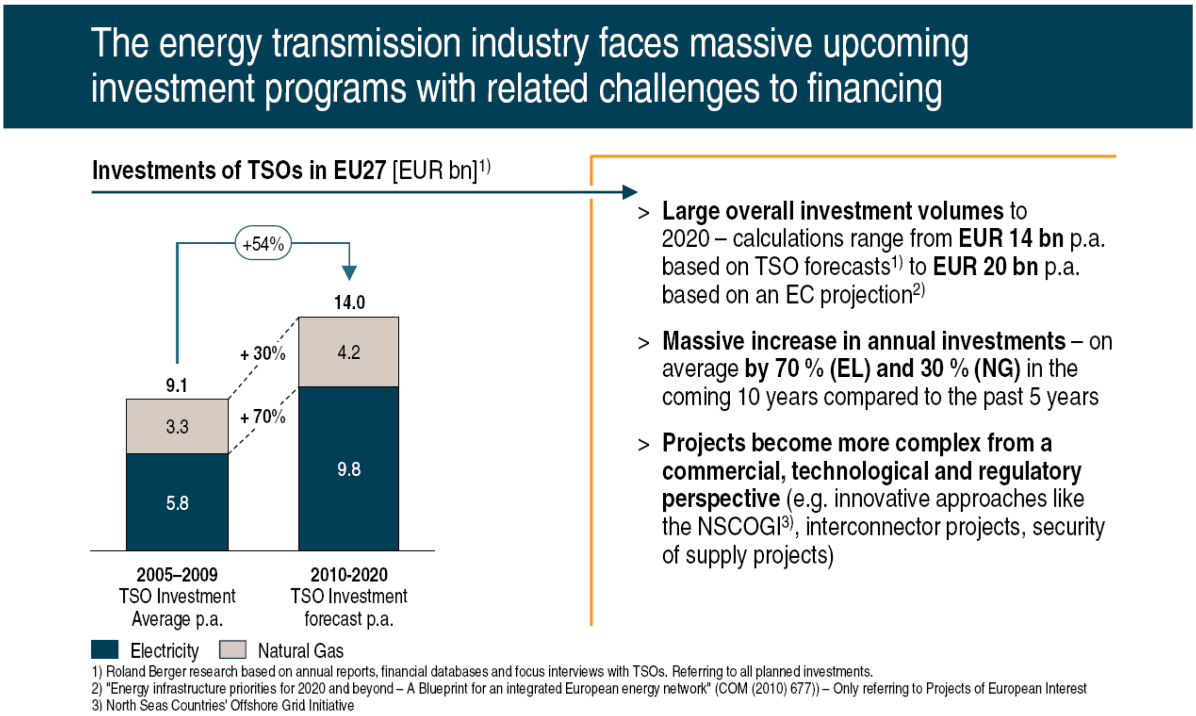
Source: GSE

Table 16: Aggregates of cost estimates for gas TYNDP 2011-2020

Infrastructure type	Number of projects	Aggregate Cost Estimate for infrastructure investment (in €10^6)	Remarks
Transmission projects – FID	62	13,711	
Storage projects – FID	26	4,260	Some projects missing from the estimate, see below for more detailed information
LNG projects – FID	11	3,570	
Transmission projects – Non-FID	97	58,556	
Storage projects – Non-FID	22	2,593	Some projects missing from the estimate, see below for more detailed information
LNG projects – Non-FID	20	6,614	Some projects missing from the estimate, see below for more detailed information
Subtotal FID projects	99	21,514	
Subtotal Non-FID projects	139	67,763	
TOTAL	238	89,304	

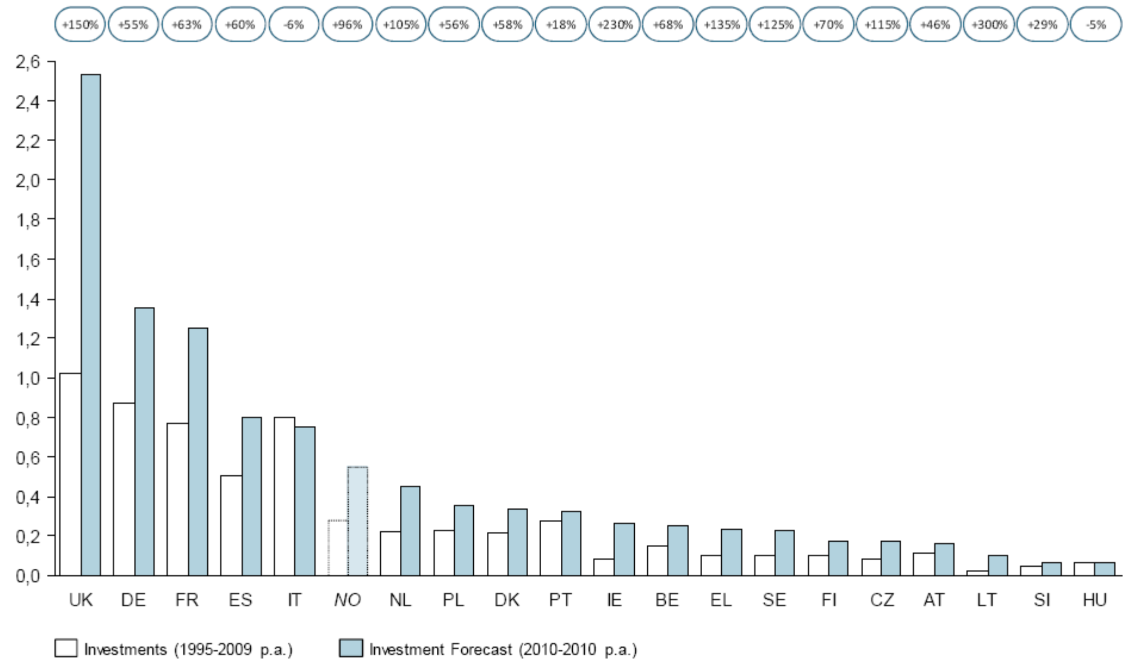
Source: ENTSOG TYNDP 2011

Figure 21: Past (2005-2009) and planned future (2010-2020) TSO investments: operators' perspective



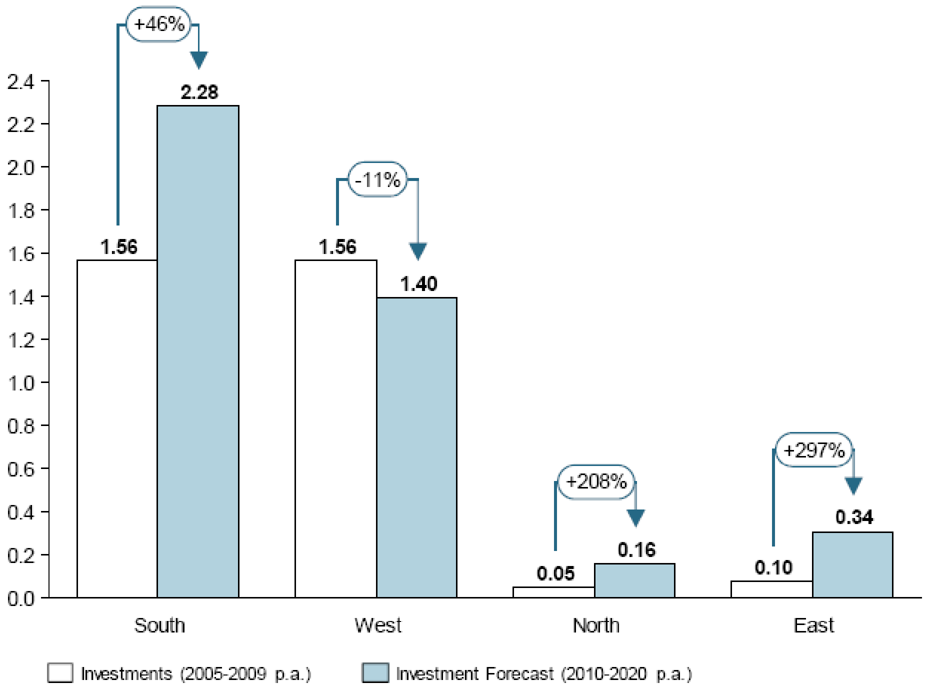
Source: Roland Berger, 2011

Figure 22: Past (1995-2009) and planned future (2010-2020) investments for selected electricity TSOs in Europe (EUR bn per year)



Source: Roland Berger, 2011

Figure 23: Past (2005-2009) and planned future (2010-2020) investments for natural gas TSOs in Europe by region (EUR bn per year)



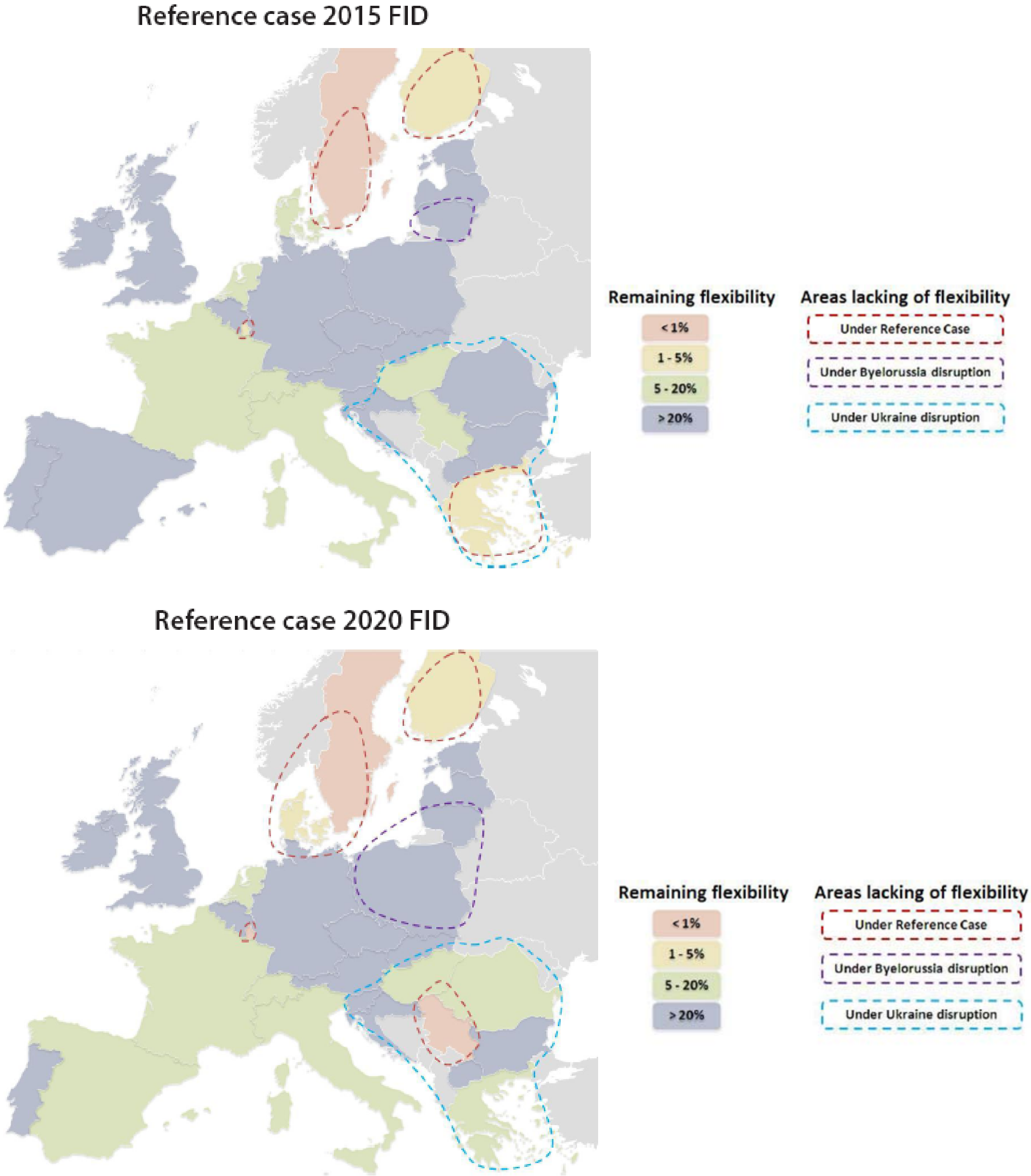
Source: Roland Berger

Figure 24: ENTSO-E analysis of main electricity transmission bottlenecks up to 2020

Source: ENTSO-E 2011 (preliminary analysis)

NB.: Arrows do not represent any projects, but only show the direction of main power flows.

Figure 25: Main gas transmission capacity reinforcement needs for 2015 and 2020 as identified by ENTSOG (scenario analysis "security of supply")



Source: ENTSO-G, TYNDP 2011

ANNEX 16
EVALUATION OF SUBOPTIONS WITH REGARD TO PERMIT GRANTING AND PUBLIC CONSULTATION

Element A.2.1 Organisation of the permit granting process

Suboption A.2.1.a: **Leading Authority without decision-making power at national level ("light one-stop shop")**

Assessment of effectiveness
Since the Leading Authority is not entitled to take the final administrative decision it is expected that the lack of managerial authority and final responsibility will not allow the Leading Authority to drive the entire process significantly forward. Effectiveness is expected to be limited as multiple procedures and permits implying double work and friction losses would continue to exist. In some countries with federal structures, such as Germany and Austria, the Leading Authority would constitute an additional layer, as coordination (and decision-making) competence would remain with multiple institutions at federal state level.

Assessment of feasibility – legal implications in MS
A slight adaptation of national legislation may be necessary in MS where a "one-stop shop"-approach is not in place, as coordination tasks may have to be (re)assigned. However, the overall permitting framework would not need to be modified and the competences of other authorities concerned would not be affected by these measures.

Assessment of proportionality
This suboption is considered to be in line with the principle of proportionality as planning and decision-making competence would be entirely left to the MS concerned, and MS would not be obliged to adapt their existing permitting framework.

Suboption A.2.1.b: Leading Authority with decision-making power at national level ("full one-stop shop")

Assessment of effectiveness
Effectiveness is expected to be significant if a full one-stop shop with decision-making power is established at national level in each MS. The Leading Authority would through its responsibility to take the final decision have the managerial power to effectively streamline and reduce the complexity of the process. The number of interfaces would be reduced for the project promoter and concentrated within one authority, such that information losses and double work can be prevented. Since the Leading Authority has been involved in the operational handling of the procedure it would be able to take an informed decision if required, if needed with support of external expertise. This is expected to have positive effects on the duration of the overall permitting process. In the Netherlands for instance, the one-stop shop as main feature of the new permitting regime has resulted in the reduction of the entire process from an average of 10-15 years to 6 years (including realisation of about 2 years), whereas in some other countries where loose coordination mechanisms such as under suboption A.2.1.b exist, procedures take on average more than 8 years. Table 17 shows that in countries where a full one-stop shop exists, the duration of the permitting process tends to be shorter. In terms of compliance and administrative costs, this suboption is expected to be more cost-effective than suboption A.2.1.a, if a coordinated approach is chosen. The administrative structures and thus the need for adaptation of national legislation, i.e. compliance costs, would be similar under both suboptions, in that responsibility would have to be allocated to the Leading Authority. However, under this suboption, the Leading Authority could take a final decision, avoid delays, and thereby reduce administrative costs spent on handling the procedures. It would not only have an impact on administrative costs, but also reduce the foregone losses due to the missing infrastructure. In general, it

should be noted that the costs related to the introduction of these measures are minor compared to the costs imposed on society as a whole if the infrastructure is not built on time.

Assessment of feasibility – legal implications in MS

Adaptation of national legislation may be extensive for this suboption if full responsibility for decision-making is chosen to be (re)assigned, and a wide range of laws can, depending on the MS and the legislation in place, be concerned. The more fragmented the process is, the more adaptation of national legislation is expected to be necessary. However, the need for adaption is expected to be less significant if authorities involved in the process retain their competences and the Leading Authority only steps in case of duly justified reasons. Feasibility of this suboption has been proved in those MS where full-one-stops with integrated procedures have been established, such as in the Netherlands, the UK, Italy etc. as legal requirements in terms of environmental and other procedures are fully respected in these MS. Respect of requirements in place is inherent to the permit granting process as authorities have to ensure that permits can withstand judicial reviews.

Assessment of proportionality

This suboption is considered to be in line with the principle of proportionality, as MS would be free to choose and establish their competent authority by a target date, and as decision-making and planning competence would be entirely left to the MS concerned. Further, since this suboption leaves flexibility to the MS to decide whether competent authorities retain their competences, the requirements to modify the permitting process are limited. These measures are broad in nature, establishing a framework within which MS can carry out the procedures according to the national specificities.

Suboption A.2.1.c: Cross-border Leading Authority ("light one-stop shop") with European Authority of Last Resort and European permitting procedure

Assessment of effectiveness

This suboption is not considered viable. A cross-border Coordinating Authority will have difficulties in reaching the "critical mass" and develop the expertise needed, as for most individual cross-border projects a new authority would have to be established (each cross-border project may involve different countries), and new staff of each of the MS involved would have to be assigned each time as staff from one MS may not be familiar with language and procedures of another MS. For a European Authority of Last Resort, an entirely new procedure would need to be established, and EU staff does currently not have the necessary expertise. Although this expertise may be developed and/or possibly subcontracted, in accordance with a new European permitting procedure, suboption A.2.1.b is expected to deliver at least the same or better results in a more timely fashion.

Assessment of feasibility – legal implications in MS

Adaptation of national legislation is expected to be necessary. Coordination competences for PCI would have to be assigned to a new authority. However, adaptation is expected to be limited as national authorities would keep their decision-making competences if the time limit is respected. In order to establish the Authority of Last Resort at European level and a European permitting procedure, adaptation of national legislation is not expected to be necessary.

Assessment of proportionality

Both elements of this suboption – the cross-border Leading Authority and the European Authority of Last Resort – do not leave competences at most appropriate level. It is expected this suboption would exceed what is necessary to achieve the objectives, such that this provision is not in line with the principle of proportionality.

Resulting from this analysis, A.2.1.b is the most preferred suboption.

Element A.2.2 Limitation in time of the permit granting process

Suboption A.2.2.a: Requirement for Member States to establish time limits for each individual PCI

Assessment of effectiveness
Effectiveness of this suboption is expected to be limited in most Member States. Although individual time limits would make it possible to take into account the national specificities of the varying permit granting processes, and the different degrees of complexity of projects, experience has shown that time limits without legal consequences in case of their expiry are relatively ineffective. In the context of the public consultations carried out, Member States were generally supporting the idea of individual time limits, however respondents across stakeholder groups, including Member States, raised the issue of consequences in case of expiry. Time limits would only be effective in Member States where certain sanction mechanisms exist, such as the deferral of the decision to a higher level. The EU would not have any means to apply any sanctions, as the legal grounds to do so would not exist.

Assessment of feasibility – legal implications in MS
This option would have limited implications on Member States' procedural law. In some Member States, legislation would need to be adapted to allow the Competent Authority to set time limits, or general time frames could be introduced by law, based on which the Competent Authority would act.

Assessment of subsidiarity and proportionality
As this option leaves substantial flexibility to Member States in defining time limits, it is considered to be in line with the principle of subsidiarity and proportionality.

Suboption A.2.2.b: Legally-binding time limits established by stakeholders in the framework of the regional fora

Assessment of effectiveness
Effectiveness of this suboption is expected to be limited as implementation would be difficult. Although the "ownership" of the decision on a legally-binding time limit is expected to have positive effects on its acceptance and could accommodate the complexities of each individual project, experience with working groups in regional fora and consultation of MS involved have shown that discussions within these groups are lengthy and consensus difficult to achieve. Although some Member States have expressed their support to such idea, those which have been involved in existing regional fora opposed this option as too cumbersome. Even if consensus is found, a legally-binding time limit can only be established through an intergovernmental agreement, whose signature by Heads of State would require additional resources and time.

Assessment of feasibility – legal implications in MS
Adaptation of national legislation would not be necessary under this suboption as intergovernmental agreements as the legal basis would be elaborated for a given PCI.

Assessment of subsidiarity and proportionality
As this suboption leaves the definition of legally-binding time limits to the MS affected, this suboption is considered to be in line with the principle of proportionality.

Suboption A.2.2.c: Legally-binding time limit established by the EU legislative act

Assessment of effectiveness
This suboption is considered to have significant effects on the duration of the permit granting process. Legally-binding time limits are crucial to incentivise promoters and authorities to complete the permit granting process in a timely fashion, and for sanction mechanisms to kick in at EU level if considered appropriate and justified. As mentioned above, an issue raised in the context of the public consultation carried out was the consequences if a time limit expires. Possibilities identified were the automatic

approval or rejection of the project. However, this is considered as a non-viable option, such that other mechanisms to sanction the expiry of a time limit should apply. The definition of time limits under the legislative act would create the legal grounds for the EU to apply sanctions, which are, across stakeholder groups, considered as crucial to enforce time limits. This suboption would be without prejudice to the time limits established for the statutory permit granting process in some MS which are, according to the analysis carried out, shorter in duration, thus not creating any adverse incentives. Further, Leading Authorities are free to identify individual time limits for the different stages of the project by elaborating a permit granting schedule for a given PCI. The Leading Authority's decision-making power at national level constitutes an additional effective enforcement mechanism if other competent authorities involved in the process do not issue the required permits on time.

A two-step approach has been identified as most effective to achieve the timely delivery of infrastructure investments, addressing both promoters and authorities. A one year time limit would be established for the statutory permitting procedure for which the competent authorities are responsible, notably from the acceptance of the submitted documents until the final administrative decision is taken. However, this one year time limit would not take into account the significant efforts needed for the preparation of application documents for which the project promoter is responsible nor administrative procedures which do not result in a legally-binding permit (such as spatial planning procedures and public debates). Further, it would not incentivise the authorities to reduce delays between the submission of application documents by the promoter and the acceptance of these by the authorities, which is a challenge in some MS where time limits for (part of) the official permitting procedure are defined, but where authorities postpone the acceptance of documents to gain time. A three years time limit would therefore be established to accommodate time consuming pre-application efforts. Respecting the fact that delays may be caused by promoters and/or authorities and that unforeseen external factors may influence the process, discretionary margin is left to the Commission at what point and in which form sanction mechanisms (reporting, withdrawal of financial support, infringement procedures) are applied.

Assessment of feasibility – legal implications in MS
Under this suboption, no major adaptation of national legislation is expected to be necessary. According to the analysis carried out, a one year time limit for the statutory administrative procedure exceeds the time limit established by legislation (in MS where these are defined). Legally-binding time limits for pre-application efforts are usually only established for individual steps of the procedure, such that these can be well-accommodated by the overall time limit.

Assessment of subsidiarity and proportionality
During public and stakeholder consultations (mainly) Member States were raising the issue of subsidiarity and advocated that time limits should be set at national level. Some Member States stated that EU measures should not prevent them to take more ambitious action.
This suboptions would take account of the concerns raised by the Member States, as they may define their individual time limits for the overall procedure, whose ambitions may exceed those set by the legislative act, and establish individual target durations for the different steps of the procedure, thereby respecting the principle of setting broad measures, leaving the individual steps in the procedure to the MS. The time limit set by the legislative act would well accommodate the time needed to carry out public consultations, which usually have a duration of 4-8 weeks. The time needed for environmental assessments can also be well integrated. As concluded by a study, an EIA decision takes less than one year from the moment of notification of the project until the final decision is taken. No major changes of procedural law are, as explained above, considered necessary, such that this option is considered in line with the principle of proportionality and subsidiarity.

Resulting from this analysis, A.2.2.b is the most preferred suboption.

Table 17: Summary of impacts

Suboption	Effectiveness	Legal implications	Proportionality	Overall evaluation
A.2.1.a – light one-stop shop	0 limited effectiveness as no decision-making competence	+ light adaptation of national legislation if assigned to existing institution	Y coordination and decision-making competence at MS level	0
A.2.1.b – full one-stop shop	++ strong effectiveness as decision-making competence can drive procedure forward, reduced complexity	0 moderate adaptation of national legislation if authorities continue to issue draft permits and if responsibilities are assigned to an existing institution	Y coordination and decision-making at MS level	++
A.2.1.c – Cross-border coordination with European ALR	- low effectiveness due to insufficient expertise cross-border and at EU level	0 moderate adaptation of national legislation for cross-border component, for ALR EU legislation	N coordination and decision making at regional/EU level	- -

Suboption	Effectiveness	Legal implications	Proportionality	Overall evaluation
A.2.2.a: Legally-binding time limits established by stakeholders in the framework of the regional initiatives	- limited effectiveness as joint agreements on legally-binding target durations are difficult to achieve and entail additional procedures	0 intergovernmental agreements to be signed	Y MS are free to agree on individual time limits	-
Suboption A.2.2.b: Legally-binding time limit of 4 years established by the EU legislative act	++ strong effectiveness with full one-stop shop. Precondition to apply adequate sanction mechanisms at EU level.	++ no adaptations expected to be necessary	Y MS are free to set more ambitious time limits for the overall procedure as well as to define time limits for individual steps in the process	++

ANNEX 17
CHALLENGES AND CORRESPONDING MEASURES PROPOSED FOR PERMIT GRANTING AND PUBLIC INVOLVEMENT

	Problems related to different phases of the process			Proposed solutions for improvement
	Phase B	Phase C	Phase D	
Inefficient administrative process	Complex and fragmented process			**One-stop shop**, including obligation to coordinate and control the process
	Lack of upfront planning and coordination			**One-stop shop**, particularly the obligation to elaborate a **permit granting schedule**, to handle **consultation procedures**, and to carry out **scoping activities**
	Lack of time limits/ long duration			Legally-binding overall **time limit**, together with **sanction mechanisms** to enforce time limits (infringements, reporting), and the obligation of the one-stop shop to control the process, based on a **permit granting schedule**
	Unclear documentation standards and lack of quality			**One-stop shop** to carry out **scoping activities** and coordinate with other authorities concerned
	Flexibility of environmental legislation			Granting of the status of **imperative public overriding interest** to ensure that the decision about the necessity to build a project, decided by Member States during the selection process, cannot be reversed by an authority later in the process
Opposition of affected population	Objections of citizens			**One-stop shop** responsible to handle consultation procedures according to principles set by the legislative act, including **early consultation** before submission of application files, and to issue **transparency guidelines.** Time frame established as 3+1 approach to leave substantial time for promoters and authorities to consult the public before decisions are taken. To be accompanied by **best-practice sharing** and **communication campaigns.**
			Appeals to courts	**Early consultation** before

				submission of application for better consensus with citizens. No legal measure with regard to judicial procedures proposed, as not considered in line with subsidiarity. **Best-practice sharing** and **communication campaigns**.
		Lengthy negotiations with landowners		**Early consultation** before submission of application for consensus with landowners. No legal measure proposed, as not considered in line with subsidiarity. **Best-practice sharing** and **communication campaigns.**

ANNEX 18
ADMINISTRATIVE COST ASSESSMENT

Introduction

This administrative cost assessment analyses the most important changes under each policy option. In line with the principle of proportionate analysis, a quantitative analysis was carried out for the measures entailing relatively significant impacts on administrative costs, notably the establishment of a regime of common European Interest, as well as the introduction of a one-stop shop approach. It should however be noted that the policy proposal does not aim at the reduction of administrative burden as such, but at making the realisation of energy infrastructure happen by increasing certainty for investors, with all consequences this entails on security of supply, market integration and the deployment of renewable energy.

Methodology

In a first step, a number of Member States was identified in which a reorganisation of the permit granting regime similar to the proposal subject to this impact assessment has been carried out, notably the Netherlands, Germany (at federal state level), the UK, and Ireland.
In a second step, a detailed questionnaire was elaborated, aiming at

a) Identifying the different activities related to the main stages of the permitting process,
b) Capturing the resources spent on these activities based on a reference project,
c) Comparing the results of a) and b) before and after the reorganisation of the permitting process.

The questionnaires and/or a request for any other information available, such as impact assessments carried out at national level, were sent to the "one-stop shop" authority as well as to the TSO(s) in the respective MS.

However, most of the respondents answered that the due to the complexity of such processes, the fact that projects vary widely with regard to their complexity, and that several projects are handled at the same time by a large number of people, it was not possible to give such detailed information. Partial data was made available by a German TSO as well as a German authority at federal state level on the existing regimes, and individual interviews were subsequently held with some TSOs to give some rough estimations on potential savings through the establishment of a national one-stop shop. These were used as assumptions in the below calculations, which give a relatively good estimate on the administrative costs incurred in a permit granting process for a large-scale energy infrastructure project. It should be noted that due to the lack of complete and detailed data, only some features of the EU Standard Cost Model[131] could be applied.

Assumptions

- Measures proposed are implemented by none of the MS.
- Two responsible authorities[132] are involved in the permit granting process (conservative assumption). Coordinating and decision-making competence would be allocated to one of these.
- No impacts on the other authorities involved at local or technical level, as it is assumed that they will continue to issue permits/opinions such that these impacts are not taken into account[133].
- Policy option A.1: acceleration of procedures by three months. Staff subsequently working for 1,5 months on the procedures at promoters' and on authorities' side, with equal distribution of

[132] Authority responsible to issue a legally-binding permit, concentrating parts of the procedure regionally or technically

[133] Exception Austria where one-stop shops at federal state level exist – not specifically taken into account.

work load over the project, and 50% impact on authorities' side (calculations based on data sent by respondents: on promoters' side savings of 820 person-hours; on authorities' side savings of 725 person-hours). Possible impacts on litigation processes are not taken into account in these calculations, as these will not be subject to the legislative act.

- Policy option A.2: 25% reduction of resources for the TSO if a one-stop shop at national level was established (interviews with TSOs and Impact Assessment UK[134]), and 34% reduction of resources on the authorities' side (Commission's calculations based on activities communicated).
- Labour costs: simple average of labour costs for the category "professionals" based on standardised ESTAT data (four-yearly Labour cost survey and the annual updates of labour costs statistics, covering both wages and non-wage labour costs, reflecting 2006 prices and 25% overhead costs)[135].

[134] UK Department for Communities and Local Government, "Localism Bill: major infrastructure projects, Impact assessment", 2011.

[135] Source: http://adminburden.sg.cec.eu.int/Manuals%20and%20documentation/080115_FINAL%20tariffs_gross%20earnings%20per%20hour%20in%2027%20MS.xls

Table 18: Results of the administrative cost assessment

Business as usual							Policy options A.1 - A.3					
Target group	**Type of obligation**	**Description of activity**	**Time spent (hours)**	**Labour costs (€ per hour)***	**Number of projects (2014-2010)****	**Total adminis-trative costs in € (BAU)**	**Total adminis-trative costs (PO A.1)**	**Change in percent (compared to BAU)**	**Total adminis-trative costs (PO A.2)**	**Reduction in percent (compared to BAU)**	**Total adminis-trative costs (PO A.3)**	**Reduction in percent (compared to BAU)**
Promoter	Securing necessary permits	Preparation of application	19.508	25,63	150	74.998.506	111.367.476	-0,03	85.889.975	-0,25	82.737.485	-0,28
		Other related activities	10.280	25,63	150	39.521.460						
		Total	**29.788**			**114.519.966**						
Authority	Issuing necessary permits	Pre-planning activities	64	25,63	150	246.048	19.787.642	-0,12	15.012.311	-0,34	12.225.049	-0,46
		Scoping	96	25,63	150	369.072						
		Checking of submitted documents	240	25,63	150	922.680						
		Coordination with other authorities involved	112	25,63	150	430.584						
		Public consultation	2.480	25,63	150	9.534.360						
		Elaboration of the permit	2.880	25,63	150	11.072.160						
		Total	**5.872**			**22.574.904**						
Total (2014-20)	**137.094.870**						131.155.118	**-0,05**	100.902.286	**-0,26**	94.962.533	**-0,31**

*Figures are not discounted

Remarks on results

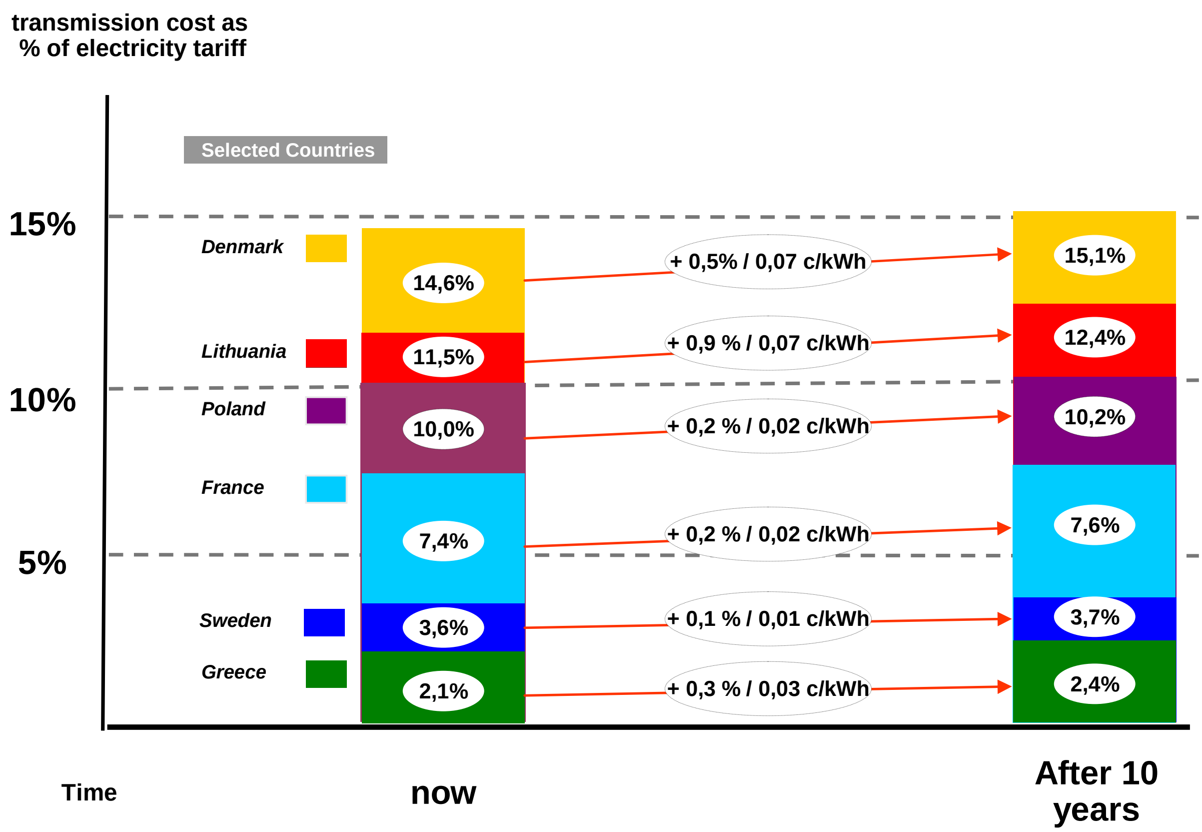
It should be noted that these results are based on the relatively conservative assumption that two authorities are responsible for the permit granting process under BAU, which are coordinating other technical, regional and/or local authorities and stakeholders involved. However, this is only one type of permitting regime existing in the different MS. Impacts would be greater if there were, as it is in many MS the case, more responsible authorities, or if the responsible authority was not or only partially coordinating other authorities and stakeholders involved. In the latter case, a shift of administrative costs from promoter towards authority is expected. However, according to the data available, in terms of pure coordinative activities such as telephone conversations, e-mails and meetings, this shift would not account for more than 2%, as more inefficiences are related to the duplication of efforts in the preparation and assessment of application files, and as half of these coordinative activities would still have to be pursued by the promoter, given that technical details need to be discussed directly. Shifts of administrative costs are also expected towards the Leading Authority from other responsible authorities. These are expected to be limited if the MS chooses to implement the coordinated approach.

In order to compare the numbers with the figures available in MS, where such an approach has already been implemented, the below table shows the reduction in full time equivalents (FTE) per year.

	Old regime (BAU)	New regime (PO A.3)
Running costs promoter (per project)	14.9	10.7
Running costs authority (per project)	2.9	1.6

On the promoters' side, figures are in line with estimations made by one promoter where a one-stop shop approach has been introduced: 11 employees are working on one project (external contracts not taken into account). On the authorities' side, the UK with an integrated permit granting regime, where all necessary expertise and decision-making power is with the Leading Authority, has a ratio of 1.9 employees per project (94 employees for 50 projects), in line with the Commission's estimations. In the Netherlands however, a ratio of 0.5 employees per project has been estimated. Here, a coordinated approach has been implemented, where expertise and decision-making power is mainly left to the other authorities involved, such that less resources at the level of the Leading Authority (20 people, 44 projects) is needed.

ANNEX 19
IMPACT OF A 2% EQUITY ADDER ON TRANSMISSION TARIFFS



Source: Roland Berger, European Commission

Main assumptions:
- equity share of 30 % for future investments
- 2 % additional annual revenue on equity
- other costs constant
- transmission tariff averaged for households and industry (excluding VAT).