NORTHSEAGRID

Offshore Electricity Grid
Implementation in the North Sea

Note on Selection of alternative Cross-Border Cost and Benefit Allocation methodologies

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1 Introduction

The objective of the IEE NorthSeaGrid project is to develop concrete solutions for integration of offshore wind farms and interconnections ("so-called integrated infrastructures") by investigating three relevant case studies from the perspective of individual stakeholders. The purpose of this paper is to describe and select alternative cost and benefit allocation mechanisms that may create viable business models for investments in integrated infrastructures. Subsequently, the selected alternative cost and benefit allocation mechanisms will be tested by a quantitative tool for the three case studies. The latter falls outside the scope of this paper. Both tasks are the focus of Work Package 5 of the NorthSeaGrid project.

Network investment volumes have to increase substantially to enable sustainable electricity generation and to improve the competitiveness of European industries, while maintaining security of supply at high levels. In order to reach these goals the EU has adopted 2020 targets and post 2020 goals. Increasing investment volumes imply an increasing number of cross-border projects between Member States. However, the current regulatory framework has a number of flaws impeding the realization of cross-border network investments in general and the realization of projects that combine offshore wind park connections and new interconnections in particular. The realization of integrated infrastructures is closely linked to the question: "who pays". Adequate cost and benefit allocation is impeded by important flaws, also referred to as market and regulatory failures:

- **Free riding effects due to asymmetry between benefit and cost allocation**. Network investments, internal or cross-border, impact the functioning of third country[1] networks either positively or negatively (often due to externalities such as loop flows). If the additional benefits for third countries are not taken into account in network investment decisions, free riding by the third country takes place. If however, the additional costs for third countries are not included in investment decisions, free riding by the investors takes place. One historical example are network reinforcements in Eastern European countries that benefitted Germany, as these network reinforcements are an alternative to congested North-South infrastructure within Germany, but where Germany did not pay for the benefits that it obtained.
- **Socialization of network costs is often a suboptimal basis for cost allocation**. Costs are distributed based upon administrative rules without recognizing the impact of economic benefits and costs of a new interconnection on the net benefits of different stakeholder groups. Hence, stakeholders that experience costs of a new interconnection may not be (sufficiently) compensated with benefits, while stakeholders that earn benefits may not pay a (fair) share of the costs of additional interconnections. A well-known example is the 50-50 administrative rule that allocates interconnection costs and congestion rents on a 50/50 basis between countries, irrespective of the benefits that accrue to each country.
- **Decisions on new network infrastructure are not recognizing the wider societal costs and benefits of new network investments**. Decisions may be based only on a commercial evaluation (congestion rents and network investment costs only) and not taking into account the wider costs and benefits for society. This may imply that network reinforcements are sized either larger or smaller than the social optimum. In an extreme case, this might even mean that network reinforcements are accepted or rejected undeservedly (ECN/SEO 2013; Supponen, 2011; Zachmann, 2013).

1 A third country is a country that is not involved in the investment decision.

- **The prioritization of wind power in cases where the offshore transmission infrastructure concerned serves both the evacuation of power from connected offshore wind farms and energy trading between connected countries.** The generation mix is largely influenced by national regulation and incentives, including support schemes for renewables, while market and network issues are increasingly coordinated at EU level. Interactions between the different elements of the value chain increasingly lead to conflicts between policies initially directed to different elements of the value chain. This especially holds for offshore wind parks which are often situated relatively far from national load centers and relatively close to the borders, and hence would profit from a cross-border approach. National priority access regimes for wind power and concomitant allocation of network capacity following Directive 2009/28/EC are at odds with energy trading between connected countries which is subject to market-based congestion management following Regulation 714/2009/EC. Priority access means that the benefits of scarce network capacity accrue to wind power, independent of the economic value realized with the network capacity. The economic value and hence network capacity payments received by project promoters are likely to be higher in case of market-based congestion management (CM) that assumes technology neutrality than in the case of CM mechanisms that assign capacity based on other criteria such as priority access.

Given these flaws impacting cost and benefit allocation, this paper aims to identify relevant alternative cross-border cost and benefit allocation (CBCA) methodologies of integrated infrastructures for further analysis in WP5. These alternative CBCA methodologies will be compared to existing CBCA methodologies (“counterfactual”) for the selected three case studies in order to create viable business models for investments in integrated infrastructures.

In order to identify the most appropriate alternative cost and benefit allocation mechanisms for the three NorthSeaGrid case studies, the following approach is followed:

- Firstly, we identify alternative CBCA methodologies (Chapter 2);
- Secondly, these methodologies are scored against a variety of stakeholder criteria (Chapter 3). This results in selection of the most feasible alternative CBCA mechanisms in the context of the NorthSeaGrid project.
- Thirdly, when applying those selected CBCA mechanisms the results are strongly dependent on the preceding WP4 CBA analysis. Therefore, we describe choices that need to be made for both the CBA and CBCA, amongst others on the types of benefit items to be included, the geographical scope of the analysis, the treatment of uncertainty, and comparison to a counterfactual. These choices are discussed in Chapter 4.
- Finally, Chapter 5 summarizes and concludes on the next steps.

2 Identification of alternative CBCA mechanisms

For cross-border cost allocation as a subset of cost allocation in general, two broad cost allocation principles can be distinguished. Firstly, we have the cost causality principle, also referred to as the beneficiary pays method which allocates the cost as much as possible to those network users (loads and generators) which benefit from the new network infrastructure. Secondly, we have the cost socialization principle which distributes costs over all users accounting for the fact that some benefits such as reliability are public goods and therefore costs cannot easily be assigned to individual stakeholders. CBCA mechanisms usually deploy one of these principles.

Generally, project promoters, supervised by regulators, apply three different general approaches for network charging. These approaches are also applicable in the context of integrated infrastructures and are summarized below (PJM, 2010; Pérez-Arriaga, 2010; Brattle, 2012):

- **Network flows**: Network flows caused by network users are determined (marginally or as average) and network costs are allocated pro-rata to each user accordingly. Network costs are finally allocated to customers as capacity-based, energy-based or fixed charges. Flow based methodologies are applied to determine the responsibility of network users in the construction of lines. They include the average participation, incremental cost related pricing (ICRP), and areas of influence methods;[2]
    - The average participation method assumes that power inflows into a node contribute to the outflows from the node in proportion to the volume of the latter (Olmos & Perez-Arriaga, 2009). After flows have been traced, the usage of each line is allocated to network users to the extent they caused flows on the node, as a rule 50% by producers and 50% by consumers. This method is applied in New Zealand, Central America, and Australia.
    - The incremental cost related pricing method calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. The marginal costs are estimated based upon DC power flow changes resulting from a 1 MW injection to the system (National Grid, 2014). This method is applied in the UK and Colombia.
    - The area of influence method allocates costs in proportion to the network use (line flows) of the transmission expansion by the identified beneficiaries (Olmos et al. forthcoming). The method is applied in Argentina and Chile.

- **Economic beneficiaries**: Network costs are allocated to those users that benefit from the reinforcement. Beneficiaries are identified either by expected changes in production costs, wholesale energy prices, energy expenditures and revenues or Power Transfer Distribution Factors (PTDFs) which provide an indication of the power flows resulting from commercial transactions. Alternatively, cooperative game theory can be deployed either to delimit distributions satisfying minimal criteria of mutual acceptability or to arrive at a unique and feasible distribution of the total gain of cooperation. In the latter case, network costs are allocated in such a way that they allow for stable cooperation of network users. Network costs are finally allocated to customers

[2] Besides, transmission cost allocation literature mentions marginal participation and mean participation methods, which are however not seen as feasible alternatives and hence discarded.

as capacity-based, energy-based or fixed charges. Recently, the beneficiary pays method has been put forward both in the US (FERC, 2011) as well as in the EU (EC 2011b; ACER, 2013d).[3] NSCOGI (2013) discusses three specific economic beneficiaries methodologies: the proportional to benefits method, positive net benefit differential method, and the Shapley value method based upon game theory;

- The proportional to benefits method allocates network costs proportionally to stakeholders' benefits i.e. every actor will have the same benefits-costs ratio.
- In case of the positive net benefit differential method, negatively affected stakeholders are compensated by all actors with (substantial) positive net benefits if an integrated infrastructure is advantageous at global level compared to individual offshore wind park connections and interconnections. Stakeholders that obtain highest positive net benefits have to pay the highest compensation to negatively affected stakeholders, and vice versa. As a consequence, opposite to the proportional to benefits method, benefit-cost ratios differ for each stakeholder.
- The Shapley value method is a solution concept in cooperative game theory. For a coalition of several players, the Shapley value assigns a unique distribution of the total gain generated by this cooperation. A specific method applied to the electricity sector in the Brazilian context is the Aumann-Shapley method (Pérez-Arriaga, 2011). Olmos et al. (forthcoming) explain this method by stating that "Locational network charges are computed for the used fraction of the grid as the cost of the network assets used by agents according to the Aumann-Shapley theory. This theory states that each agent is responsible for the average incremental use it makes of the network when joining a great coalition that ends up containing all generators and loads in the system."

- **Postage stamp**: Network costs are allocated uniformly among network users (sometimes consumers only), either based upon the yearly consumed or produced energy (MWh) independent of system peak and (often) location, or the (simultaneous) contribution of network users to the system peak (MW) independent of location and usage. NSCOGI (2013) discusses the Louderback's and min/max contribution methods which partially allocate cost uniformly using a postage stamp method;
  - The Louderback's method defines a direct contribution to every actor and allocates residual costs of the global project, after direct contributions have been subtracted, across all stakeholders. Residual or common costs are shared proportionally to the difference between stand-alone costs and attributable costs (the latter is equal to the direct contribution). The allocation of residual costs is thus performed with a postage stamp method, while the direct contribution is based on the economic beneficiaries method.
  - The min/max contribution method is similar to Louderback's method but with different allocation of residual costs. The residual cost contribution of those responsible for connecting offshore wind parks to the onshore grid is the average load factor of the offshore wind park times interconnector costs at minimum, and interconnector costs times nominal power at maximum. Thus, in the case of the min/max contribution method again the residual costs are allocated with a postage stamp method. The minimum

3 If the economic beneficiaries method is applied usually the CBCA is based upon a CBA. Since a CBA is made of a prospective situation, the CBCA is usually an *ex-ante* cost allocation mechanism as opposed to *ex-post* mechanisms that are based upon the actual costs and are updated regularly afterwards.

contribution is calculated using the average production (MWh) while the maximum contribution is based upon peak production (MW).

3 Selection of most feasible alternative CBCA options

Depending on the characteristics of the particular system (size, how well meshed the network is, fraction of the total electricity costs attributable to transmission, number and type of prospective new network users) and preferences of policy makers, the most adequate method of allocation may vary. Therefore, we evaluate the alternative CBCA mechanisms with a set of the most common criteria brought forward in the literature (PJM, 2010; Perez-Arriaga, 2010; NSCOGI, 2013).

Common criteria applied to evaluate cost allocation methods are:

- *Cost causality / reflectivity*: those who cause more/less costs should pay for more/less costs. This principle is firmly settled in European legislation (see e.g. Directive 2009/72/EC).
- *Efficient economic signals for generation and load*: network cost charging influences decisions of network users, both in the short-term (for operation decisions) and in the long-term (for investment & location decisions). Efficiency reflects the extent to which these signals induce private decisions that promote system efficiency.
- *Understandability*: transparency of the tariff structure for stakeholders, so that they understand how costs are allocated and how their decisions affect the network costs.
- *Administrative ease*: implementation efforts, such as gathering and using the necessary data for cost allocation.
- *Ability to reflect system changes over time*; the utilization of network infrastructure changes over time due to investments and changes in operation of generation and demand as well as changing market circumstances. This criterion reflects the possibilities for updates of network charges.
- *Stability of tariffs*; predictability of future network costs is important for investment decisions of network users.
- *Recognition of the public good and positive externality aspects of transmission infrastructure*; the transmission system has characteristics of a public good. Grid reliability is a public good, as it is non-rivalrous and (partially) non-excludable. Furthermore, the transmission system expansion can create positive and negative externalities; benefits or costs respectively that accrue to other parties but are not taken into account in cost allocation. This criterion reflects the extent to which the public good and externality aspects can be included in the particular cost allocation method.
- *Non-discrimination;* similar network utilization by different network actors should lead to similar network charges. Opinions differ on what constitutes discrimination. Differentiation of network charges to time-of-use or location is generally not considered as discrimination, while differentiation to (generation) technology is seen as discriminatory. This criterion is not included in Table 1 below as it depends on the definition of non-discrimination whether there is an impact, if any, on the scores of cost allocation methodologies.

Given these criteria, Table 1 provides our own expert judgment of the different cost allocation methodologies in the context of integrated infrastructures foreseen in the NorthSeaGrid project. Together with the weights given to each criterion, an overall score for each cost allocation methodology could be determined. The scoring and weighting of each criterion for each cost allocation methodology could be validated by stakeholders (e.g. Stakeholder Advisory Board and/or NSCOGI).

Table 1: Expert judgment of three cost allocation methodologies in the context of NorthSeaGrid

Criterion	**Network flows**	**Economic beneficiaries**	**Postage stamp**
Cost causality	0/+	++	--
Efficient economic signals for generation and load	0/+	++	--
Understandability	-	+/-	++
Administrative ease	--	-	+
Ability to reflect system changes over time	+	+	+
Stability of tariffs	+	+	+
Recognition of the public good and positive externality aspects of transmission infrastructure	-	-	+

Source: own expert judgment based upon literature survey. Legend: ++ very positive, + positive, 0 neutral, - negative, -- very negative.

The **network flow methods** score moderate compared to other cost allocation methodologies. First of all, some leading researchers say there is no indisputable procedure to measure “physical network utilization”, all evaluation methods are questionable, and the economic rationale for network usage methods is weak (Pérez-Arriaga, 2010). Therefore, these methods score moderate on the criteria ‘cost causality’ and ‘efficient economic signals for generation and load’. On the other hand, in meshed AC networks flow methods are considered as the only appropriate way to determine costs and benefits. PJM (2010) also states that ‘the international trend is toward the use of location-based or flow-based methods to allocate and recover at least some portion of transmission costs’. In market pricing arrangements, such as flow-based market coupling in Europe and locational marginal pricing (LMP) in several states of the US, DC load flow analysis is applied to divide scarce network capacity as efficiently as possible. As such, cost causality and economic signals to load and generation of network flow methods can be assessed positively. The same holds for stability of tariffs. Often ex-ante (i.e. prospective) cost allocation is applied with cost allocation remaining unchanged during the lifetime of the network upgrade. If instead cost allocation is updated after installation of the network upgrade, network tariffs are less stable. Concerning understandability, these methods require network studies which are complex and difficult to understand for stakeholders. Moreover, earlier work packages of the NorthSeaGrid project do not provide the required network model data for applying these type of methods, lowering administrative ease. Besides, network flow methods usually measure the marginal impact on flows, which leaves aside public good and externality aspects. As a consequence, for many aspects these methods are considered to be inferior compared to other cost allocation methodologies.

The **economic beneficiaries** cost allocation methodology is preferred to the other methodologies on the criteria cost causality and efficient economic signals for generation and load (both on the short and long term). The game theory variant also takes into account strategic behavior of stakeholders. Apart from this variant, economic beneficiaries methodologies often score better on understandability for the general public than methods based upon network flows. These methods, especially those based upon game theory, are both more difficult to understand and require more data than postage stamp methodologies, lowering administrative ease. Concerning stability of tariffs, if costs are allocated to identified expected beneficiaries (i.e. prospectively), network tariffs are considered to be stable. If instead cost allocation would be updated after installation of the network upgrade because of changes in beneficiaries, stability of network tariffs would be lower. Finally, if all costs are allocated by this method positive external effects such as reliability are not taken into account and not allocated to all network users but to a selected set of actors that experience advantageous monetary impacts. Overall, a tendency exists towards application of the economic beneficiaries cost allocation methodology both in the US and the EU, see for instance the CBCA method developed by ACER (2013d) (see also Annex I).

The **postage stamp cost allocation method** is preferred on several aspects, amongst others it is simple to understand and easy to administrate. A well-known example of this method is the often applied 50/50 division of interconnection costs between EU member states. Furthermore, allocating costs over consumption and/or generation (either in energy or capacity terms) implicitly recognized that a public good such as reliability is enjoyed by all network users. Besides, if production and consumption are stable, tariffs will be stable as well. On the other hand, when network reinforcements are performed for economic rather than reliability reasons postage stamp methods are increasingly inefficient. Given the increasing fluctuations in both generation (due to increasing share of RES-E) and demand (electric vehicles, heat pumps), power flows are increasingly variable as well, implying that the average situation is often not representative of the huge diversity of network situations in reality. As a result postage stamp methods are increasingly unreflective of costs and provide inefficient economic signals to network users both in the short and long term, decreasing overall system efficiency.

Conclusions

The preferred cost allocation methodology depends on the weights and scores that are given to different criteria. Nowadays the postage stamp method is often preferred because of its understandability, administrative ease, and recognition of the public good and positive externality aspects of transmission infrastructure. Given the increasing complexity of electricity systems (higher shares of distributed generation and less predictable RES-E, higher network controllability due to technologic developments, and more interactions between national power systems due to European wide market integration), simple cost allocation methods such as postage stamp are increasingly in conflict with the cost causality principle and provide inefficient signals to network users. It is likely that this will provoke growing opposition from negatively affected customer groups. More advanced cost allocation methods are the economic beneficiaries and network flow methods. They score better on cost causality and efficient economic signals for generation and load, but this comes at the price of both a lower understandability and administrative ease than postage stamp methods. The economic beneficiaries methods score better than network flow methods, amongst others on aspects such as understandability and administrative ease. Concerning the latter, given that within NorthSeaGrid no detailed network model is being used, we expect that insufficient data would be available for applying network flow methods. Consequently, we propose to leave the network flow methods aside. Therefore, we propose to consider two alternative cost allocation methodologies for further elaboration:

1. **The economic beneficiaries method, notably the positive net benefit differential method** which allows for compensation payments between positively and negatively affected stakeholders. This method is recommended and elaborated upon by ACER (ACER, 2013d; ACER, 2013e);
2. **A combination of the economic beneficiaries and postage stamp methods**. A combination of different cost allocation methods allows for utilization of the advantages of separate methods. First, it allows for allocation of the part of the costs that can be clearly and indisputable assigned to beneficiaries, while remaining costs are recovered by postage stamp so that uncertainty around part of the cost and benefit items can be better taken

into account. Furthermore, application of the postage stamp method to part of the costs allows for recognition of the public good and positive externality aspects of transmission infrastructure. One possibility is the *Louderback method* (NSCOGI, 2013) which defines a direct contribution to every actor and allocates residual costs of the global project, after direct contributions have been subtracted, uniformly across all stakeholders.

4 Application of the selected alternative CBCA mechanisms

For applying the selected alternative cost allocation mechanisms, notably the economic beneficiaries method, a number of important choices need to be made for the CBCA (and CBA) concerning;

a. CBA as starting point for CBCA analysis and possible benefit items to include[4]
b. Geographical scope
c. Managing uncertainty
d. Comparison to counterfactual

Each choice is discussed below.

4.1 Choices around CBA methodology and possible benefit items to include

Integrated infrastructures as PCIs subject to CBA at Union level

The EC requires a harmonized energy system wide cost-benefit analysis at Union level for all projects in the Ten-Year Network Development Plan (TYNDP) of ENTSO-E (see Article 21(1)b of EC (2013a)) as well as for each project that qualifies as Projects of Common Interest (PCI) (see Article 11 of the same regulation). Article 11 also prescribes the development of the CBA methodology by ENTSO-E and G respectively.[5] The current draft of the ENTSO-E methodology is a mix of a cost-benefit analysis and a multi-criteria analysis. However, as noted by Meeus et al. (2013) if projects would be ranked based upon the monetized net benefit in combination with quantitative indicators, it implies an implicit monetization of effects that have not been monetized explicitly. For this and other reasons (double counting etc.), many researchers and stakeholders advised a full cost-benefit analysis during the last years. ACER (2013a) acknowledges the ENTSO-E multi-criteria approach as the first step in the development of the expected methodology for a cost-benefit analysis. However, it calls for a fully monetized CBA as the appropriate long term solution and therefore considers 'clear, transparent, quantified/monetized criteria for the CBA methodology and for the subsequent selection of PCIs from the TYNDP list as crucial requirements from the regulatory perspective' (ACER, 2013a). Also integrated infrastructures are within the scope of PCIs, since the Northern Seas offshore grid (NSOG) is one of the priority electricity corridors mentioned in Annex I of EC (2013a). In the first Union list of PCIs some project clusters are already explicitly aiming for integrated infrastructures.

4 Given the fact that the main discussion is about the inclusion of benefit items, we refrain here from discussing cost items. For a discussion on the cost items we refer to ACER (2013d) amongst others.

5 Afterwards ACER and EC subsequently have to deliver their opinion while member states may also deliver their opinion. ENTSO-E should adapt the methodology and then submit it to the EC for approval. Regular updates and methodology improvements are foreseen. This process is still ongoing; ENTSO-E started in 2012 the development of the CBA methodology and after several consultations and improvements it published its guideline by 14 November 2013 (ENTSO-E, 2013b). ACER provided its opinion on 30 January 2014 (ACER, 2014) and the EC in July 2014. ENTSO-E is expected to deliver the final guideline by the end of 2014.

CBA as starting point for CBCA analysis

Coupling the CBCA to the CBA is in line with EC (2013a). Article 12 (6) of the latter states 'In deciding to allocate costs across borders, the relevant national regulatory authorities … shall seek a mutual agreement based on, but not limited to, the information specified in paragraph 3(a) and (b)'. Paragraph 3(a) is about the project specific cost benefit analysis. Consequently, the cross-border cost allocation (CBCA) decision needs to be based upon the CBA.

The phrase 'but not limited to' is a compromise added after discussion within the European Council. During the legislative process, the requirement has been weakened. A precondition for application of cross-border cost allocation is now that at least one project promoter has to request relevant national authorities to apply cross-border cost allocation (article 12 (2)). Besides, only if National Regulatory Agencies (NRAs) do not reach agreement on an investment request including cross-border cost allocation within six months, or upon joint request from the NRAs concerned, the decision is referred to ACER (article 12 (6)). For both cases, ACER specified a CBCA method in order to clarify the details to be submitted for projects which have reached sufficient maturity and to facilitate a consistent CBCA approach among NRAs. This CBCA method is not obligatory yet for cross-border projects, but rather a recommendation to NRAs (ACER, 2013d).

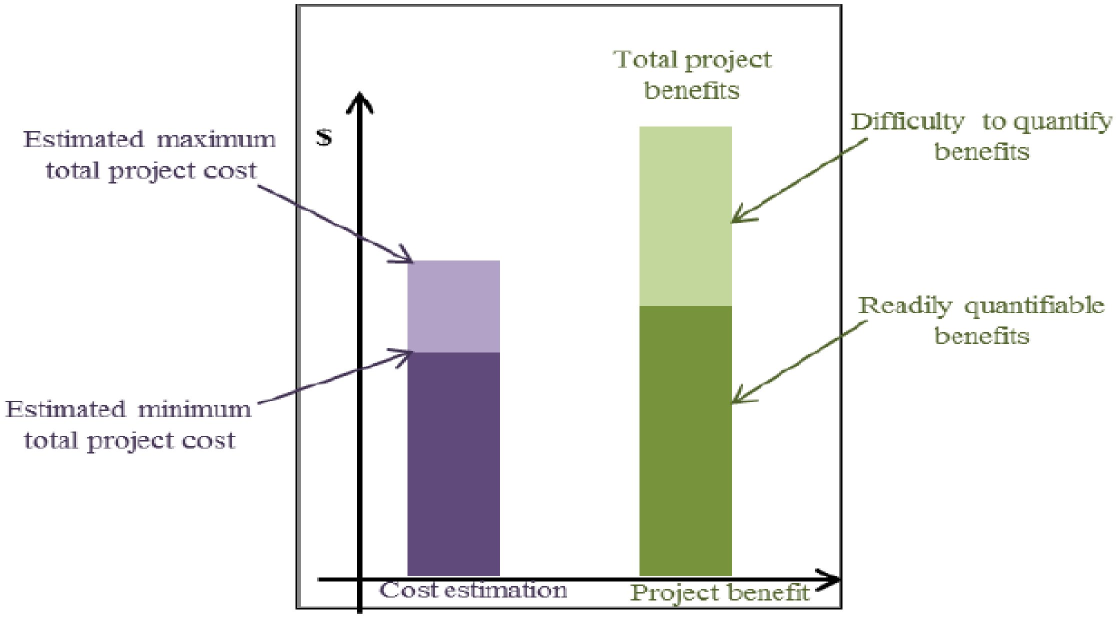
As indicated before, integrated infrastructures such as those being assessed in NorthSeaGrid are within the scope of PCIs. Consequently, these are also within the scope of the CBCA method specified by ACER. We assume that the CBA will be the main basis for the CBCA since the results of the CBA are available in any case and are unlikely to be neglected by the party which will lose compared to its contribution based upon the CBA.

Possible benefit items to include

Several studies do not only stress the importance of using a benefit framework (CAISO, 2004; Brattle, 2012; ECN/SEO 2013; ENTSO-E, 2013a), but also emphasize that it is important to take into account all relevant sources of project benefits. Otherwise there is a major risk that a cost-benefit analysis underestimates the total project benefits, as illustrated in Figure 1 below.

Policy makers seem to acknowledge this risk. Article 12(4) of EC (2013a) states that 'In deciding to allocate costs across borders, the economic, social and environmental costs and benefits … shall be taken into account'. Annex IV of this Regulation contains a very detailed long list of effects which should be taken into account in the assessment of PCIs. On the other hand, it is not straightforward to quantify some of the benefits (e.g. impacts on landscape, voltage quality, harmful substances affecting environment), data availability is limited (e.g. value of lost load for quantifying security of supply impact), and/or they require advanced modelling efforts (e.g. behavioural effects of network investments on investments in production capacity). As a consequence, different studies take into account different effects.

Figure 1 Importance of taking into account all project benefits for project selection



Source: ENTSO-E (2013a)

Table 2 below highlights the benefit items that are taken into account by five publications i.e. ACER (2013a), Meeus et al. (2013), ECN/SEO (2013), CAISO (2005), and Brattle (2013). For comparative purposes, we also show the benefit items that are taken into account in the preliminary analysis of NorthSeaGrid (2014).

In the context of the Energy Infrastructure Package in general and the PCI selection process in particular, the NRAs ordered a consultancy study of Frontier Economics.[6] Based upon this study, ACER identified a number of benefit items.[7] Also the FP7 THINK project studied the draft CBA methodology of ENTSO-E of 2012 of the proposed EU regulation on trans-European energy infrastructure (COM(2011) 658 final) and the benefit items to be included (Meeus et al. 2013). Furthermore, a study for the Dutch Ministry of Economic Affairs identified the cost and benefit items that should be part of a "standard" cross-border network investment assessment framework that is optimal from a societal welfare perspective and could be applied on a more structural rather than on an eclectic basis (ECN/SEO 2013). CAISO (2004) is among the first studies that have provided a refined methodology to evaluate the economic viability of proposed network upgrades, to be paid by its network users. This methodology is –with some refinements – applied by CAISO (2005) to evaluate the Palo Verde-Devers line No. 2 project (also known as Path 26). A relevant recent report in the US context is Brattle (2013). It provides a checklist of transmission benefits as well as an overview of transmission benefits considered by different independent system operators (ISOs) in different geographical areas in the US. Finally, the draft publication of

6 The study itself is still confidential, however a presentation summary was made publicly available (Frontier, 2012).

7 Table 2 of ACER (2013a). ACER (2014) confirmed this position.

NorthSeaGrid (2014) shows the main assumptions and first draft results of the application of the Imperial College market simulation model to integrated infrastructures.

Based on Table 2, three important observations can be made. First, the selected studies can be roughly divided into two groups; a first group of studies is mainly based upon other studies and derives general implications (e.g. ACER, 2013a; Brattle, 2013; Meeus *et al.* 2013) while others mainly show the results of their own analysis of benefit items (e.g. CAISO, 2005; ECN/SEO, 2013; NorthSeaGrid, 2014). This may explain the generally smaller scope of the latter type of studies; taking into account many effects entails severe implications for market modelling and concomitant model computation time, and therefore is sometimes avoided.

Second, the table shows that Meeus *et al.* (2013) identify far less benefit items of transmission infrastructure than the other studies. They recommend to limit the CBA to the most important effects (in terms of size) to reduce the complexity of the CBA. The set of effects they consider as important is quite limited. Only in some specific cases they do see a need for considering effects on social and environmental sensibility, competition and market power, and early deployment (indicated with crosses within brackets). Instead, several other studies stress that all benefits should be taken into account. CAISO (2004) stresses that some benefits items are difficult to quantify and therefore are left out, but 'nevertheless we should keep refining the methodology and keep exploring potential ways to quantify these additional transmission benefits.' Brattle (2013) states that 'omitting consideration of difficult-to-estimate benefits inherently assigns a zero value and thereby results in a systematic understatement of total project benefits'. They refer to earlier studies to provide examples of quantification of all types of benefits. ECN/SEO (2013) conducted a case study for a fictitious interconnection between Denmark and the Netherlands, which illustrated amongst others that the inclusion of effects beyond 'standard' effects (i.e. trade effects as well as investment and O&M costs) can change the results of the investment evaluation from negative to positive.

Third, some benefit items are not explicitly mentioned (in some studies) since they are part of the other benefit items mentioned. For example, all studies (except NorthSeaGrid (2014) that does not mention it) highlight that CO_2 emissions are already included in trade benefits when emission pricing mechanisms exist, since the purchase of emission rights decreases production costs savings. Consequently, these studies do not contain a separate benefit item related to CO_2 emissions as this would mean double counting. Also avoided generation curtailment and increased RES capacity as a result of additional electricity infrastructure are usually internalized in the production cost savings and therefore not separately included in the catalogue of benefit items. Note that additional electricity infrastructure here includes grid connections to offshore wind parks that are part of integrated infrastructures; hence the effect of integrated infrastructures is captured by the benefit items identified. More details can be found in the discussion of the separate benefit items below.

Table 2: Catalogue of benefit items of selected CBA studies

No	Benefit item[8]	ACER (2013a)	Meeus et al. (2013)	ECN/SEO (2013)[9]	CAISO (2005)	Brattle (2013)	NorthSea Grid /IC (2014)
1	Trade effects[10]	X	X	X	X	X	X
2	Variation in losses	X		X[11]	X	X	X
3	Security of supply	X		X[12]		X[13]	X
4	Variation in generation curtailment	X					
5	Releasing national constraints	X		X	X[14]	X[15]	X[16]
6	Future costs for new (avoided/delayed) generation investments	X		X	X	X	
7	Future costs for new (avoided/delayed) transmission investments	X				X[17]	
8	Optimisation of regulating power and ancillary services	X		X[18]		X	X[19]
9	Technical resilience (system safety margin)	X			X[20]	X[21]	
10	Social and environmental sensibility	X	(X)	X		X	
11	Effects on competition and market power	X	(X)	X	X	X	
12	Early deployment benefits		(X)			X[22]	

Let us discuss each benefit item separately.

1. Trade benefits

New electricity infrastructure allows for increased dispatch of generators with lower marginal production costs, displacing generators with higher marginal costs. The former type of generators will also frequently set market clearing prices. As a result, changes in producer surplus, consumer surplus and congestion rents (together the

8 Descriptions No. 2-11 are taken from ACER (2013a).

9 This study mentions some additional benefit items (voltage quality, government budget), but which either cannot be quantified due to lack of data (voltage quality) or unclarities about the direction of the causal relationship (government budget). Apart from that, the size of these effects is probably limited.

10 Trade effects include producer and consumer surplus, and congestion rents. This item is referred to in different ways in the studies. Some studies call it “socio-economic welfare”. We prefer “trade effects”, since “socio-economic welfare” is a broader notion; all items discussed influence socio-economic welfare.

11 Not explicit in framework, but accounted for in case study as part of O&M costs.

12 Effect of interconnections on power interruptions.

13 Part of reliability and resource adequacy benefits.

14 Automatically accounted for through effects on LMPs.

15 Automatically accounted for through effects on LMPs.

16 Most important national constraints are taken into account by bidding zones.

17 Synergies with future transmission projects.

18 Integration of renewable energy: flexibility [in balancing market].

19 Costs of providing reserves.

20 Part of operational benefits category.

21 Part of reliability benefits category.

22 Part of other potential project-specific benefits.

trade benefits) will be obtained. Benefits resulting from altered producer and consumers surpluses and congestion rents are usually identified with market simulation studies that model the decrease of variable operation costs of power generation given new electricity infrastructure. Market simulation studies typically deploy 'security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints', Brattle (2013), p. 34. These benefits are generally considered as the most important source of benefits of new electricity infrastructure (with producer and consumer surplus gaining importance compared to congestion rents). They are an output of the Imperial College market model.

2. Variation in losses

New electricity infrastructure can reduce the loading of existing lines and therefore network losses by redistribution of power flows among existing and new transmission paths. On the other hand, network losses of certain lines within countries may also increase due to increased power transfers. Often constant loss factors are applied, which do not take into account the first effect mentioned. Alternative methods simulate changes in transmission losses with market simulation models with sufficient granular network representation, network models, or utilize marginal loss charges (Brattle, 2013). In case of CAISO (2005) reduced losses amount only to $ 2 million annual benefits. However, Brattle (2013) shows that for the ATC Paddock-Rockdale project the NPV of expected benefits under the high environmental scenario amounts to $ 15 million of total benefits of $ 220 million. They state that especially during system peak-load conditions the benefits of reduced losses can make up a surprisingly large part of the project (investment) costs, i.e. in the order of 30% to roughly a half of project costs, both in energy and capacity value). ACER (2013d) recommends to deploy network models to identify the variation of losses on the network elements (lines and transformers) which are affected by the new infrastructure. The Imperial College market model takes into account converter and line losses.[23]

3. Security of supply

An interconnection adds flexibility to the system and as such may allow for improving 'the ability of a power system to provide an adequate and secure supply of electricity under ordinary conditions' (ENTSO-E, 2013b). During ordinary conditions ordinary contingencies may happen. ENTSO-E (2013b) defines a contingency as the loss of one or several elements of the power transmission system. Different types of contingencies are chosen as "proxies" for hundreds of other events that could affect the grid. A differentiation is made between ordinary, exceptional and out-of-range contingencies. Generally N-1 (outage of network element or load) situations are considered as ordinary contingencies and N-2 events as exceptional contingencies. Network simulation studies can identify for these situations which network busses would show overloadings, with loss-of-load reliability metrics such as Expected Energy Not Supplied (EENS) and Loss of Load Expectancy (LOLE). Alternatively, market simulation studies with simplified network representation can be applied to identify situations where load is not entirely met by generation. New electricity infrastructure may decrease the average length and frequency of interruptions and consequently contribute to transport electricity from generation to load during more hours of the year. Multiplying EENS (LOLE can be translated to EENS) with the average customer weighted value of lost load (VOLL) provides insight in the monetary security of supply benefit of additional electricity infrastructure.

[23] Personal communication from Danny Pudjianto of Imperial College.

The Imperial College market model utilizes network capacities that are secure capacities which meet the N-1 security standard. Furthermore, it includes a reliability assessment module that calculates the loss of load expectation (LOLE) by assessing whether generation will be available for each hour of the year to meet the load in situations with and without an additional network infrastructure project. Annualised costs of new transmission and back up generation capacity are compared against the opportunity costs of loss of load (with a VOLL of €50,000 per MWh), while the LOLE is maintained below 4 hours in a year.

4. Variation in generation curtailment

As stated before, avoided generation curtailment and increased RES capacity as a result of additional electricity infrastructure are already internalized in the production cost savings and therefore should not be separately accounted for. This explains why many studies, including NorthSeaGrid that uses the Imperial College market model, do not put forward this item as separate benefit item. An exception is ACER (2013a) that states that in case those effects are not yet accounted for in market studies [that deliver production cost savings], they can be taken into account separately based upon network studies.

Concerning increased RES capacity, it is clear that the renewable energy capacity is already fixed by targets, infrastructure as such does not increase the renewable energy capacity. At the same time, better infrastructure indeed reduces the renewable energy capacity to be installed to achieve the renewable energy targets (Meeus et al. 2013) since enlarging markets by interconnecting regions decreases the need for generation curtailment. This impact is already taken into account in the production cost savings, as noted above.

5. Releasing national constraints

Depending on the project at hand, the effect of additional network infrastructure on releasing national constraints can be quite substantial. For example, certain variants of the Cobra project (cable between Denmark and the Netherlands, with the connection of a German offshore wind park foreseen at a later stage) are sometimes considered as relevant for relieving congestion on North-South transmission lines in Germany. Taking into account effects on national congestion requires either a network model or a market model with a more refined geographical representation than one zone per country. ECN/SEO (2013) advised the client to apply a market model with (simplified) national network representation to calculate avoided congestion management costs (as well as the impact on national network investment costs, see item no. 7). US studies like CAISO (2005) already assume locational marginal pricing (LMP, also called nodal pricing) and thus automatically take into account the impact of interconnections on relieving national constraints in their market models. ACER (2013d) suggests that an European market study, which is currently based on one-zone per country, should be complemented by local market studies. The Imperial College market model takes into account the main national constraints due to a network representation that contains up to five bidding zones for some EU member states.

6. Future costs for new (avoided/delayed) generation investments

Additional electricity infrastructure can defer or avoid generation investments on both sides of the added infrastructure. An increase of network capacity implies that low-cost power plants will be more often in-the-money, increasing their running hours and profits, while power plants with higher costs will be more often out-of-the-money, decreasing running hours and profits. Imagine power plants in country A have comparative advantages compared to country B due to for instance shorter distances for fuel supply and/or the availability of cooling water. Then, additional generation investments will be made in country A while in country B generation investments may be deferred or avoided. The case study conducted by ECN/SEO (2013) showed that especially the effects of an investment in an interconnection on investments in production capacity can be quite substantial compared to other non-standard effects (i.e. effects other than social welfare effects). However, one has to bear in mind that it is very difficult to estimate these effects on investments in generation capacity adequately outside a market simulation model; especially if it concerns a meshed grid. The Imperial College model does not optimize the generation portfolio for economic purposes, therefore this effect will be left aside in the cost allocation assessment.

7. Future costs for new (avoided/delayed) transmission investments

New integrated infrastructures will impact on the congestion of other (inter)national lines in the network, and therefore are likely to affect the economic viability of other transmission investments. On the one hand, the integrated infrastructure may entail additional trading patterns and therefore increase the expected utilization of network infrastructures and associated benefits. On the other hand, in a meshed network several investments may compete with each other, implying that the realization of one of these projects diminishes the benefits of competing projects.

In order to account for these interactions between proposed investment projects, one can apply the Take Out One at the Time (TOOT) methodology that excludes an individual project from a portfolio of projects and evaluates the overall benefits with and without the individual project (ENTSO-E, 2013b). The portfolio then exists of the whole forecasted network i.e. existing network plus all projects to be evaluated. In this case the benefits identified are not affected by the order of investments. If several competing projects are included, the portfolio assessment based upon TOOT may provide a negative result; then competing projects should be left out of the portfolio and evaluated one-by-one based upon the existing network infrastructure. The latter methodology is known as Put IN one at the Time (PINT) (ENTSO-E, 2013b). In other words, as noted by Meeus *et al.* (2013), there is no perfect baseline and both TOOT and PINT should be applied.

ACER (2013a; 2014) agrees with the application of the TOOT methodology for the CBA of a transmission plan such as the TYNDP, but also requires equal treatment of -often competing- TSOs' and third party projects. Also Brattle (2013) is in favour of considering portfolio of projects, since that may allow for compensating stakeholder costs resulting from one project by stakeholder benefits from another project, and consequently may simplify the necessary cost allocation analyses. The four external peer reviewers of this study doubt however whether this will be the case, since they suspect that stakeholders would know how they benefit from major individual elements of a proposed cluster of transmission projects.

However, in the context of individual project assessments the application of the TOOT methodology can be burdensome; it requires insight in all network reinforcements realized in a future year and accounting for all these reinforcements in modelling studies. CAISO (2005) did not explicitly account for the effect on alternative network investments, although the Palo Verde–Devers No. 2 500 kV line was identified in initial screening studies of the electricity network in the SouthWest transmission expansion plan. Furthermore, one alternative transmission project brought up by stakeholders during the study was tested by sensitivity analysis. NorthSeaGrid (2014) evaluates three individual case studies for 2030 based upon the 2020 network infrastructure as foreseen by the TYNDP of ENTSO-E (2012). Furthermore, effects of the three case studies are also considered jointly. This seems sufficient as it is clearly out of scope to consider effects of EU-wide or regional network plans within the framework of this study.

8. Optimisation of regulating power and ancillary services

New network infrastructure can reduce the costs associated with balancing supply and demand as well as other ancillary services (voltage stability, reactive power etc.). Balancing requirements and cost associated with balancing intermittent resources will increase with the higher penetration of intermittent resources. These balancing and ancillary services costs are commonly not taken into account in the trade benefits since market models assume perfect foresight of production and consumption, and only take into account a limited set of technical generation and network restrictions. In reality, deviations of actual from expected power production and consumption occur and restrictions such as ramping constraints, start-up times, and minimum load operation of generation units limit the flexibility of the power system. Additional network infrastructure provides access to flexibility abroad, and reduces the societal costs due to imperfect foresight and out-of-market actions such as reliability must run (RMR) and minimum load cost compensation (MLCC). CAISO (2005) provides estimates of the benefits of a new interconnection in reducing the costs of the mentioned out-of-market actions. Brattle (2013) discusses the operational benefits to system operators that HVDC transmission lines can offer in optimization of ancillary services to address reliability challenges, system stability, voltage support, and black start capability. It depends on the market model deployed whether these issues, generally referred to as 'unit commitment', can be easily included in the analysis. The Imperial College model considers the amount of reserve for dealing with uncertainty (including generation availability and RES output, demand uncertainty), since though it takes into account the output profiles of wind power generation in a deterministic way, the stochastic element of it is dealt with reserves. Thus, the impact of an interconnection on the cost of providing reserve as part of the broader effects on regulating power and ancillary services is taken into account.

9. Technical resilience (system safety margin)

ENTSO-E (2013b) defines technical resilience or system safety as 'the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies)'. Electricity infrastructure can also act as insurance policy against this type of contingencies with low probability but possibly high impact. Since the benefit category security of supply (item no. 3 above) is limited to the impact of electricity infrastructure on supply of electricity under ordinary system conditions, technical resilience is considered as a separate benefit category. According to Brattle (2013), exceptional contingencies can be analysed with the same type of loss-of-load reliability metrics as under item 3 above. Electricity infrastructure investments 'tend to either reduce loss-of-load events (if the planning reserve margin [i.e. system safety margin] is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.' In the Imperial College model transmission outages related to exceptional contingencies are not modelled, although the impact of outages can be derived by running sensitivity studies with de-rated capacity. Given that several other sensitivities will be modelled within the NorthSeaGrid project, this specific sensitivity is left aside.

10. Social and environmental sensibility

This benefit category is broad; it includes several types of emissions, as well as other environmental and social impacts.

As indicated above, CO_2 emissions are already included in trade benefits. However, other types of emissions are not included in trade benefits. CAISO (2004, 2005) values the effects of interconnections on NOx emissions. ECN/SEO (2013) monetizes the effects on NOx, SO2, PM10, NH3, and SOx emissions by using emission factors and shadow prices, while accounting for the time value of money (by using discount rates). The aggregated effect was limited compared to other monetized effects. Instead, Meeus et al. (2013) state that local and environmental costs are (at least partially) internalized in infrastructure costs because of the requirements of the Environmental Impact Assessment (EIA) (Directive 85/337/EEC) concerning the impact on human beings, local fauna and flora, material assets, and cultural heritage. The costs of the measures to meet these requirements are included in the infrastructure costs. Indeed, it can be postulated that if norms are fulfilled costs they are internalized in infrastructure costs. Consequently, we do not consider this effect further.

At the same time, effects on landscape are not yet part of requirements at EU level. Unfortunately, effects on landscape are quite difficult to monetize. ECN/SEO (2013) distinguish two types of landscape effects; note that electricity infrastructure can affect both spatial usage and ‘landscape perception’. If the project would affect the spatial usage, the effect can be estimated by the opportunity costs of the spatial usage i.e. the value of the lost activity. Infrastructure in densely populated areas, leisure areas, or wildlife areas would result in more welfare loss than infrastructure in other areas. If effects on landscape cannot be related to spatial usage, monetization is deemed to be problematic. In case information on spatial usage is not readily available in the NorthSeaGrid project, this partial effect is left aside.

11. Effects on market power

An interconnection allows for sharing of generation capacity across borders, not only increasing the competition between generation units (changing producer surplus under item no. 1) but also lowering their market power and the frequency of price spikes. Meeus *et al.* (2013) state that some effects like effects on competition and market power are quite comparable between projects and therefore can be neglected. This assumes that projects are not compared to the counterfactual on a project-by-project basis, but as a project portfolio. In practice, this is often not the case. According to CAISO (2005) and Brattle (2013) market power effects can be quite substantial. CAISO (2005) indicates that reduction of monopoly rents for the project evaluated (Palo Verde-Devers line No. 2) amount to $ 28 million[24] expected annual benefits of total annual benefits of $ 119 million (24% of total annual benefits). Brattle (2013) show that for the ATC Paddock-Rockdale project the NPV of expected benefits under the high environmental scenario amounts to $ 49 million of total benefits of $ 220 million (22% of total benefits). Instead, based on a simple rule-of-thumb outside the model the case study in ECN/SEO (2013) showed limited price effects of an interconnection, implying negligible market power effects. However, in our view this result suggests the insufficiency of applying a non-model based rule-of-thumb method rather than the limited size of

[24] The difference between the modified societal perspective and the societal perspective is equal to the producer’ monopoly rents.

market power effects. The Imperial College market model does not simulate situations with market power. Since non-model based methods are unlikely to deliver adequate results, this benefit item is left aside.

12. Early deployment benefits

Electricity infrastructure projects can increase knowledge about deployment of technologies or innovative projects (Meeus et al. 2013). At the same time, there is always a risk that investments are performed in technologies that later turn out to be inefficient. In the context of the NorthSeaGrid project, early deployment benefits may be harnessed from integrated infrastructures. However, Meeus et al. (2013) state that these type of benefits are exceptional; early deployment benefits are often already internalized in the infrastructure costs through specific EU funds for demonstration. They suggest weighting the non-internalized benefits of being a first mover against the option value of waiting. Note that such a real option approach is generally quite complex to apply and can be considered as a topic for a separate study. Given the difficulties to determine early deployment benefits, this benefit item is left aside.

4.2 Geographical scope

Another choice to be made is the number of countries to consider in the CBA and CBCA. This depends on the electricity network technology deployed; Direct Current (DC) versus Alternating Current (AC). In case of DC technology, network flows are well controllable, limiting the impacts of the additional infrastructure on the countries that are not directly involved in the investment decision. In case of AC technology, network flows are less controllable and follow the path of least resistance without taking into account borders. Consequently, a wide range of third countries may experience costs or benefits due to the realization of integrated infrastructures. In order to prevent free riding effects (as discussed in the introduction), studies generally advise to broaden the geographical scope of a CBA to neighbouring countries and countries further afield (CAISO, 2004; Brattle, 2013; ECN/SEO, 2013).[25] In line with this, EU Regulation No 347/2013 (EC, 2013b) contains a number of statements on the geographical scope of CBAs;

- Article 12 (3): the investment request and request for cross-border cost allocation shall be accompanied by 'a project-specific cost-benefit analysis … taking into account benefits beyond the borders of the Member State concerned'.
- Annex V.10 prescribes that 'the area for the analysis of an individual project shall cover all Member States and third countries, on whose territory the project shall be built, all directly neighbouring Member States and all other Member States significantly impacted by the project'.
- Annex V.11: 'The analysis shall identify the Member States on which the project has net positive impacts (beneficiaries) and those Member States on which the project has a net negative impact (cost bearers).'

Likewise, we propose to include all those countries in the CBCA which experience significant effects of the integrated infrastructure in the CBA.

[25] The ECN/SEO (2013) case study also illustrated that only if the CBA includes the effects on third countries, the investment has a positive social welfare effect.

4.3 Managing uncertainty

The value of integrated infrastructures depends on the forecast of future system conditions, such as forecasted demand, fuel costs, and generation availability, affect generation and demand and hence the utilization of the projected infrastructure. Changes in future system conditions can significantly alter the potential benefits of network reinforcements (i.e. bandwidth around expected value). The relationship between transmission benefits and underlying system conditions is in many cases nonlinear (CAISO, 2004), making it difficult to extrapolate single estimates. Moreover, network expansion can be considered as an insurance against extreme events and contingencies, with low probabilities but large effects. Since the value of transmission projects is disproportionally higher during more challenging market conditions (Brattle, 2013), it is important to account for the effects of uncertainty in CBA and CBCA analyses.

Uncertainties are usually taken into account in model-based analyses with scenario and sensitivity analysis. A scenario is defined as a coherent, comprehensive and internally consistent description of a plausible future (ENTSO-E, 2013b). Scenario analysis is mainly deployed to take into account several combinations of major exogenous uncertainties such as fuel price trends, load growth, hydro conditions, locations and size of generation due to technological changes, and future EU legislation. Sensitivity analysis is applied to catch the impact of specific (policy) variables such as the possible abolition of priority dispatch, restrictions to international eligibility for national RES-E subsidies, and changes in national network tarification methodologies on the outcome of the analysis. Furthermore, bandwidths are often calculated and reported to account for uncertainties in the estimation and valuation of effects.

For depicting uncertainties of future system developments on benefits of network expansion, often a two stage procedure with market and network simulation models is applied. This relates to the multiple purposes and values of network infrastructure in facilitating economic, reliability, and sustainability goals. First, the market simulation model is deployed for each scenario for an economic optimization of the generation dispatch in each node of an interconnected system, for every hour of the year, using a simplified representation of the grid. As a next step, the output of the market-based assessment is used as an input for network analysis to check the effects of the network expansion on network reliability (analysis of load flows, stability and short circuits) under different conditions. Network simulation models use a simplified representation of generation and demand profiles, but include a detailed representation of the grid. Subsequently, the output of network studies can be used to update the market simulation model. Usually both methods are applied in such an iterative way to analyse different relevant aspects from market and network perspective in sufficient detail (ECN/SEO, 2013; ENTSO-E, 2013b). However, since there is no detailed network model foreseen within NorthSeaGrid, this two-stage approach is not applicable to NorthSeaGrid.

The uncertainty in potential benefits of integrated infrastructures influences the CBCA of those infrastructures in two ways. First of all, given the bandwidth of benefits depending on scenario at hand, only benefits that are relatively certain can be allocated in an indisputable way between countries (and stakeholders). Given that a multi-scenario approach and sensitivity analysis are foreseen in NorthSeaGrid (2014), this issue can be addressed adequately in the CBCA. Secondly, high levels of uncertainty stimulate project phasing or deferral (of certain components) of the project. This maybe disadvantageous for the development of integrated infrastructure projects that combine offshore wind park connections and interconnections, since stakeholders could be inclined to construct one of both and apply a 'wait-and-see' approach in order to reduce the uncertainty of the remaining part, impeding the realization of synergies of integrated infrastructures. However, since phasing of investments is clearly a decision that pertains to the CBA, for the CBCA we take the investment decision including possible choices around phasing for granted.

4.4 Comparison to counterfactual

For evaluating costs and benefits, and hence cost and benefit allocation, usually the situation with the project ('project alternative) is compared with the situation without the project ('counterfactual'). The *project alternative* is here the realization of integrated infrastructures ('integrated case'). Besides the realization of integrated infrastructures, also other project alternatives are available to improve the integration of electricity from offshore wind parks and to remove barriers for cross-border trading. Examples are policy measures to improve the utilization of existing infrastructure by deployment of storage, generation flexibility/curtailment, demand side management (as far as it concerns the interconnector part), or smaller/partial network investments. The first category of policy measures is also called 'resource alternatives' (CAISO, 2004).

The *counterfactual* is a separate connection of an offshore wind park and an interconnection ('base case'). The counterfactual is not equal to doing nothing as that would mean that electricity from offshore wind parks cannot be transported and existing bottlenecks for cross-border trading would remain. CBCA methods influence the distribution within the value chain and with that the realization of projects that are identified to have positive net benefits for society. A higher number of projects can be realized through better cost and benefit allocation between countries and stakeholders. CBCA methods itself cannot be considered as project alternative.

The comparison of the integrated case with the base case results in positive or negative net benefit differentials for each country and subsequently for net benefit differentials for each stakeholder category (producers, consumers, transmission owners, governments, others) within each country. For identifying the impact of CBCA mechanisms on the realization of integrated infrastructures alternative CBCA mechanisms need to be compared to the currently often applied 50/50 division of costs and congestion rents between directly involved countries. Different CBCA mechanisms are likely to result in different net benefit differentials between integrated case and base case for each country and stakeholder category identified.

5 Summary and conclusions

In Chapter 2 different alternative CBCA mechanisms are identified; network flows, economic beneficiaries, and postage stamp. In Chapter 3 these methodologies are scored against a variety of important criteria including cost causality, efficient economic signals for generation and load, understandability, administrative ease, ability to reflect system changes over time, stability of tariffs, recognition of the public good and positive externality aspects of transmission infrastructure. The preferred methodology depends on the weights that are given to different criteria. The economic beneficiaries and postage stamp methods do have the highest number of positive scores. In order to overcome the disadvantages of each separate method, in practice cost allocation is often performed as a combination of economic beneficiaries and postage stamp methodologies. Therefore, we propose to consider two alternative cost allocation methodologies for further elaboration:

1. Economic beneficiaries method, notably the *positive net benefit differential method* which allows for compensation payments between positively and negatively affected stakeholders. This method is recommended by ACER (ACER, 2013d; ACER, 2013e);
2. A combination of the economic beneficiaries and postage stamp methods. A combination of different cost allocation methods allows for utilization of the advantages of separate methods. One possibility is the *Louderback method* (NSCOGI, 2013) which defines a direct contribution to every actor and allocates residual costs of the global project, after direct contributions have been subtracted, uniformly across all stakeholders.

For applying the selected alternative CBCA mechanisms, notably the economic beneficiaries method, Chapter 4 discusses a number of important choices that need to be made;

a. CBA as starting point for CBCA analysis and possible benefit items to include
b. Geographical scope
c. Managing uncertainty
d. Comparison to counterfactual

CBA as starting point for CBCA analysis and possible benefit items to include

A CBA is commonly seen as a starting point for CBCA analysis, in academic and TSO studies as well as in recent EU legislation for PCIs. The EU-wide CBA framework that is being developed by ENTSO-E for PCIs seems applicable to all PCIs, including those involving integrated infrastructures. Besides the cost items, it is important to take into account all relevant sources of project benefits to prevent that the CBA underestimates the total project benefits, resulting in a net negative result for society and making the CBCA superfluous. However, it is difficult to quantify and monetize some ‘advanced’ benefit items adequately, which can be a reason to leave them out.

Concerning the benefit items that are taken into account in the analysis of the integrated infrastructures, we conclude that the Imperial College market simulation model contains major benefit items such as favourable effects on trading, variation in network losses, security of supply, releasing major national constraints, and optimisation of regulating power and ancillary services. . Some benefits which are arguably more difficult to quantify such as future costs for new (avoided/delayed) generation and transmission investments, technical resilience (system safety margin), social and environmental sensibility, effects on competition and market power, and early deployment benefits are not included in the market modelling for the NorthSeaGrid project.

Geographical scope

In line with different studies and EU regulation we propose to include all those countries in the CBCA that experience significant effects of the investments in integrated infrastructure according to the CBA. This may involve both the interconnected countries and third countries.

Managing uncertainty

The value of integrated infrastructures depends on the forecast of future system conditions, such as forecasted demand, fuel costs, and generation availability, which affect generation and demand and hence the utilization of the projected network infrastructure. Changes in future system conditions can significantly alter the potential benefits of network reinforcements. The uncertainty in potential benefits of integrated infrastructures influences the CBCA of those infrastructures as well for two reasons. First of all, given the bandwidth of benefits depending on scenario at hand, only benefits that are relatively certain can be allocated in an indisputable way between countries (and stakeholders). Given that a multi-scenario approach and sensitivity analysis are foreseen in NorthSeaGrid (2014), this issue can be addressed adequately in the CBCA. Secondly, high levels of uncertainty stimulate project phasing or deferral of (certain components) of the project. This maybe disadvantageous for the development of integrated infrastructure projects that combine offshore wind park connections and interconnections, since stakeholders could be inclined to construct one of both and apply a 'wait-and-see' approach in order to reduce the uncertainty of the remaining part, impeding the realization of synergies of integrated infrastructures. However, since phasing of investments is clearly a decision that pertains to the CBA, for the CBCA we take the investment decision including possible choices around phasing for granted.

Comparison to counterfactual

The project alternative is here the realization of integrated infrastructures ('integrated case'). The counterfactual is a separate connection of an offshore wind park and an interconnection ('base case'). CBCA methods influence the distribution within the value chain and with that the realization of projects that are identified to have positive net benefits for society. A higher number of projects can be realized through better cost and benefit allocation between countries and stakeholders. The comparison of the integrated case with the base case results in positive or negative net benefit differentials for each country and subsequently for net benefit differentials for each stakeholder category (producers, consumers, transmission owners, governments, others) within each country. For identifying the impact of CBCA mechanisms on the realization of integrated infrastructures alternative CBCA mechanisms need to be compared to the currently often applied 50/50 division of costs and congestion rents between directly involved countries. Different CBCA mechanisms are likely to result in different net benefit differentials between integrated case and base case for each country and stakeholder category identified.

Next steps

As foreseen by Annex I, the application of the two selected alternative cost allocation methodologies will be tested by a CBCA tool for the three case studies. Based upon the CBA results, the CBCA tool will take into account the benefit items, include the relevant countries that experience significant effects of the integrated infrastructure, allow for identification of a bandwidth of results by using several scenarios of future system conditions, and test the impact of selected alternative CBCA mechanisms by comparing these alternatives against a 50/50 division of costs and benefits between countries ('postage stamp').

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Annex I: Relevant EC legislation impacting CBCA options

Energy infrastructure Package

- New cross-border infrastructures encompassing connections to offshore wind parks as well as interconnections will usually be part of the TYNDP. If a project is part of the TYNDP,[26] it can qualify as Project of Common Interest (PCI), which makes them eligible for accelerated permitting procedures, EU financial assistance (e.g. Connecting Europe Facility) in case the project is not commercially viable, and cross-border cost allocation by ACER.
- Regulation No 347/2013 provides guidelines for trans-European energy infrastructure, and especially PCIs. Article 12 concerns cross-border cost allocation:

  - Paragraph 1: 'The efficiently incurred investment costs, which excludes maintenance costs, related to a PCI … shall be borne by the relevant TSO or the project promoters of the transmission infrastructure of the Member States to which the project provides a net positive impact, and, to the extent not covered by congestion rents or other charges, be paid for by network users through tariffs for network access in that or those Member States.'
  - Paragraph 2: Paragraph 1 only applies if at least one project promoter requests the relevant national authorities to apply this Article for all or parts of the costs of the project. This paragraph is added after discussion on COM(2011) 658 final.
  - Paragraph 3: 'The investment request shall include a request for a cross-border cost allocation and shall be submitted to all the national regulatory authorities [NRAs] concerned, accompanied by the following … (c) if the project promoters agree, a substantiated proposal for a cross-border cost allocation'.
  - Paragraph 4: NRAs have to take coordinated decisions on the allocation of investment costs to be borne by each system operator for the project, as well as their inclusion in tariffs, taking into account actual or estimated congestion rents or other [network] charges as well as ITC revenues.
  - 'In deciding to allocate costs across borders, the economic, social and environmental costs and benefits … shall be taken into account'
  - 'In deciding to allocate costs across borders, the relevant national regulatory authorities … shall seek a mutual agreement based on, but not limited to, the information specified in paragraph 3(a) and (b)'. Paragraph 3(a) is about the project specific cost benefit analysis.
  - Paragraph 6: either if NRAs do not reach agreement on investment request including cross-border cost allocation within six months, or upon joint request from the NRAs concerned, the decision is referred to ACER.
  - Paragraph 9: Article 12 does not apply to merchant projects.

- EU Regulation No 347/2013 does not specify the level of detail of the information to be submitted by the project promoters under Article 12(3). Therefore, ACER has submitted Recommendation No 07/2013

26 For establishing the first Union wide list of PCIs, PCIs did not have to be part of the TYNDP.

(ACER, 2013d) to facilitate a consistent approach among NRAs. It contains a list of detailed information to be provided by project promoters when submitting a CBCA request including a '**summary data template**' as well as high level principles that NRAs shall follow when handling a CBCA request.

- List of detailed information
    - ACER stresses the link between project-specific CBA and CBCA request, and requires analysis of expected ITC revenues and other revenues /charges.
    - Annex I: 'Cross-border cost allocation shall be based on a project-specific and **per country disaggregated** cost benefit analysis (CBA).'
    - Annex I: 'Furthermore, market-study simulation tools should be able to identify the variation of SEW benefit in each country. They should be designed for allowing provision of the estimated benefits **for specific stakeholder groups within a country** (variation of producer surplus PS, variation of consumer surplus CS and variation of congestion revenues CR)'. 'The Agency recommends that every benefit component is disaggregated at national level for each year of analysis … A higher level of disaggregation (PS, CS, CR) is required for the SEW benefit.'

- Treatment CBCA requests
    - Projects should be sufficiently mature i.e. amongst others strong confidence on expected costs and benefits assessed by the CBA and good knowledge of range of probable cost and benefit values (sensitivity analysis)
    - Only compensations if one country hosting the project is deemed to have a negative net benefits
    - Countries to which a project provides a net positive impact should contribute to provide compensation if positive net benefit exceeds a significance threshold equal to 10% of the sum of positive net benefits accruing to all net benefiting countries.
    - Contribution to be paid proportionally to the level of net benefits exceeding the significance threshold. ACER (2013e) provided an example of the calculation.
    - At the moment no public information is yet available on the amount of CBCA requests issued by project promoters.