Energy Policy 39 (2011) 3096–3105

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Social cost-benefit analysis of electricity interconnector investment: A critical appraisal☆

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ARTICLE INFO

Article history:
Received 15 December 2009
Accepted 15 February 2011
Available online 25 March 2011

Keywords:
Project evaluation
Infrastructures
Interconnector

ABSTRACT

This paper examines the economic analysis (social cost-benefit analysis) underlying two decisions to build an interconnector (NorNed and the East–West interconnector) in Europe. The main conclusion is that current interconnector and transmission investment decisions in Europe are unlikely to maximize social welfare. The arguments are as follows. (i) It is unclear how much demand for transmission capacity and interconnectors actually exists, and thus the benefits of investment are unclear. (ii) Both analyses underlying the investments studied are incorrect, to the point where, in one case, even the sign may be wrong. (iii) The main criticism concerns the fact that they do not take the resulting changes in generator investment plans into account and ignore the (potential) benefits of increased competition. (iv) Several smaller issues can be improved, such as the discount rate used. (v) Decisions at the European level are taken very differently, and approval may depend on which authority grants approval. (vi) Interconnector decisions receive the most attention, although most money goes to transmission investments. Two research recommendations for future improvements are formulated.

1. Introduction

Transmission and interconnection capacity between different markets or TSO regions should be increased and investment is insufficient according to many including the European Commission and the European TSO's (EC, 2007b, 2008b; ERGEG, 2009, p. 8; ENTSO-E 2010; see also ECF (2010) and PwC (2010)).[1] This new capacity should increase trade between cheap and expensive production areas, fight the market dominance of incumbents and increase competition, connect more renewable energy sources to the grid and increase security of supply (EC, 2007b, 2008b; ERGEG, 2009, p. 8). Consentec and Frontier Economics (2008, p. 7) estimate transmission investments needed to exceed €100 billion.[2] ENTSO-E (2010, p. 126) estimates the investment required up to 2020 to cost between €57 and €64 billion for about 42,100 km of new or refurbished network routes; this is about 14% of the total ENTSO-E transmission network of 300,000 km. About 25% of these new network routes will be new DC links, like the two cases studied here (ENTSO-E, 2010, p. 15). Given the vast amounts of investment at stake, careful decisions are necessary. Therefore, this paper focuses at two European cost-benefit analysis used to underpin actual investments, to test whether CBAs currently made are delivering efficient and adequate investments.

In a social cost-benefit analysis (CBA),[3] costs and benefits measure all differences in society with and without a project. Not only effects for the decision maker are included but also the externalities. This is done for all potentially good project alternatives. Methodologically there are two alternative methods: more limited cost-benefit calculations, and multi-criteria analysis (MCA).

☆This paper benefited from discussions at the Second Tilec Round Table on Energy, from seminar participants at Delft University, the Bremen Energy Institute, the Dutch Competition Authority, the 2009-IAEE Conference in Vienna and the Market Design 2009 Conference in Stockholm. Furthermore, discussions with Gert Brunekreeft, and comments on earlier versions from Eric van Damme, Robert Haffner, Jan-Paul Dijkman, David Newbery, Bert Tieben, Laura Malaguzzi Valeri, Bert Willems and two anonymous referees greatly improved the paper. The author is grateful to the Electricity Policy Research Group of Cambridge University, and the Bremer Energie Institut at Jacobs University for the hospitality enjoyed while writing parts of this paper. The author is solely responsible for any remaining errors.

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[1] EC (2007b) complained that not much investment is taking place. A similar statement holds for the US (see Joskow, 2005a). EC (2007a) gives several explanations why current low investment might mean underinvestment. However, several other explanations for low investments are possible without underinvestment: excessive investment prior to liberalization resulting lower required levels of investment now (Brennan, 2006; Moran, 2004) and calls for more investment may come from actors with an interest in building them (White et al., 2003).

[2] The absolute investments in transmission are large, but constitute only a relatively small fraction of the total cost of the electricity system (IEA 2002, p. 50). However, given the sharp rise in the cost of transmission investments, currently grid investment costs are comparable to generation assets on a rough per MW or MWh basis (see ENTSO-E 2010, p. 126.

[3] For an in-depth treatment of CBA see, for example Brent (2006), Eijgenraam et al. (2000) and EC (2008a).

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doi:10.1016/j.enpol.2011.02.049

Sometimes, a cost-benefit calculation is made without including all of social costs and benefits; for example, in PJM the investment decision is based on reliability reasons or solely on congestion revenues in the case of market investment (see Joskow, 2005a, 2005b). This is unlikely to lead to socially optimal investment if external effects are important, or if both congestion and reliability benefit from a single investment.

In an MCA, projects are scored on various criteria, such as physical quantities, money and expert judgements. Weights are allocated to the criteria before the scores are combined into an overall rating for each project. The basis for the allocated weights is not always clear but often includes the preferences of policy makers or researchers involved. The double-counting of effects is more difficult to avoid than with a CBA because strict criteria for the inclusion of effects are lacking (Eijgenraam et al., 2000). An example of an MCA is the Baltic Energy Market Interconnection Plan (CESI, 2009). The criteria used are the benefit/cost ratio, where benefits refer only to market benefits and costs refer to investment costs, timing for the authorization and construction, and risks. Because it was impossible to determine the weights, CESI used equal weights. This has the drawback that relatively unimportant criteria or overlapping criteria (like the time required to realize a project, which is also included in the discounted value of the future benefits) are overrated.

The strength of a CBA is that all the effects need to be formulated precisely. A downside is that it is hard to determine how to use each factor in the CBA (such as the uncertainties related to quantifying the costs and benefits). MCA can deal with less strict criteria more easily. MCA and CBA both try to determine what the (physical) consequences of a specific project will be. While the MCA leaves it to the decision maker in dialog/debate with society to make the trade off, CBA tries to infer the weights by establishing how citizens make these trade-offs by expressing all effects in monetary terms. Therefore CBA is likely to get closer to answering the question of what happens to welfare than MCA. Therefore this article focuses on CBA.

A CBA also seems to be in line with ERGEG and ENTSO-E policy. The European Regulators' Group for Electricity and Gas (ERGEG 2010, p. 2) uses several criteria to judge the work of ENTSO-E on the desirability of new transmission capacity. ERGEG uses technical criteria (including a thermal criterion, stability criterion, voltage and reactive power criteria and short-circuit criterion) and several economic criteria to assess the social welfare arising from possible investment. The socio-economic evaluation should include a CBA, which should include investment costs, project risk analysis, change in losses and possible synergies and dependencies between the projects. It also includes socio-economic criteria such as: the exchange of ancillary services; the value of a more integrated market, for example by managing price differentials effectively across congested areas; the improved welfare of end-customers within the European market; the risk and costs of energy and/or power shortages (security of supply) and generation optimization (generation according to the merit order). How these various criteria should be weighted is not specified. ENTSO-E (2010, pp. 16–17) states that TSOs must use the following four criteria to evaluate investments in new transmission projects. (i) The investment should maintain or improve current high reliability to which end-users are accustomed. (ii) Investment should positively address social welfare. To this aim, cost-benefit analyses are undertaken by TSOs for every transmission project. (iii) New technological advances are taken into account. (iv) Grid planning should anticipate long-run perspectives beyond the following 10 years. This is an analysis of CBAs as mentioned by ENTSO-E under (ii).

This paper focuses at two large investments to increase interconnection capacity. However, capacity can also increase because of smaller measures, like changes in the operation, the allocation mechanism, congestion management,[4] the relaxation of reliability standards and investment in IT systems or small investment (see Hirst, 2000; Joskow, 2005b, p. 14; Léautier and Thelen, 2009, p. 131; Turvey, 2006; Kirschen and Stribac, 2004). Some of the objectives of more interconnection (i.e. more competition between generators) can also be reached with other measures like favouring entry (Küpper et al., 2009), or breaking up the largest companies (Tanaka, 2009). Although it is important for a CBA also to include low-cost solutions, this article does not discuss this in more detail. To illustrate its importance two examples follow. In 2004 capacity worth almost €50 million was not utilized on the Dutch–German border, almost half the total value of this interconnector capacity (EC, 2007a, p. 185). Under-using and misusing of the UK–France interconnector amounted to €289 million from 2002 to 2005 (Bunn and Zachmann, 2010). The importance of improving the use of existing interconnectors has been seen and improvements are underway. For example, market coupling between Belgium, the Netherlands and France reduced congestion: the percentage of time the prices between the Netherlands and France differed fell from 90% to 37% after market coupling in 2007 was established (see ERGEG, 2009, p. 16, Küpper et al., 2009).

In a CBA, all costs and benefits are relevant. The costs include investment costs, operational and maintenance costs, environmental impact, real options, the impact on electricity loss and other system costs (frequency control, spinning reserve and other ancillary services costs). The costs mainly follow directly from calculations made by engineers. On the benefit side, two benefits stand out: efficiency benefits and security of supply benefits (or reliability benefits).[5]

Efficiency benefits, including trade and competition benefits, can arise from investing in interconnection and transmission because an extended network increases the possibilities for trade and competition between generators. In the short run, this can increase allocative efficiency (the electricity goes to the consumer with the greatest willingness to pay; redistribution cannot improve welfare) and productive efficiency (the same electricity cannot be made at a lower cost by having some producers produce more and others less). Allocative and productive efficiency also include the absence of mark-ups over the marginal cost based on market power, since these mark-ups distort the optimal allocation of goods among consumers, of production among producers and the optimal quantity produced. More competition may also reduce x-inefficiency (where firms could produce at a lower cost than they actually do)[6] and it may influence dynamic efficiency (through investments in R&D and new technologies).

Increase in reliability is often the main reason behind grid investments (Joskow, 2005b). Valuing increased reliability requires (i) an estimate of the increase of reliability (e.g. the decrease in MWH of electricity not delivered due to interruptions) and (ii) a valuation of increased reliability (difficult, but possible, see de Nooij et al., 2007). Often a distinction is made between investments necessary to maintain reliability (by meeting certain engineering

[4] For congestion management at borders, see Kristiansen (2007), Turvey (2006) and Consentec and Frontier Economics (2004).

[5] For a more in-depth discussion of all costs and benefits, see the next two sections; de Nooij (2010), Turvey (2006) and Malaguzzi Valeri (2009).

[6] X-inefficiency (Leibenstein, 1966) can result from workers or management putting in substandard levels of effort, from misdirected effort, imperfect rationality and from markets that are not perfectly competitive. Leibenstein argued that gains of improved x-efficiency are likely to far exceed gains from improving allocative and productive efficiency. X-inefficiency is a departure from strict neo-classical economics, and as such is subject to criticism, see Stigler (1976) and Leibenstein's response (1978). Frantz (2007) gives an overview of studies that quantify x-inefficiency.

reliability criteria) and investments to facilitate the market (including all non-reliability benefits; see, for example AER, 2007). Joskow (2005b, p. 2,3) asserts that this is 'nonsense': reliability investments can have significant effects on trading opportunities and on the use of operating reserves.[7] The 42,100 km of new network routes needed in Europe ENTSO-E (2010, p. 15) gives three reasons why they are needed: connecting renewable to the grid accounts for 20,000 km, security of supply for 26,000 km and the internal energy market for 28,500 km. The sum total being larger than 42,100 km indicates that lines are built for several reasons.

This article investigates the underpinning of investment decisions in interconnectors in more detail, using CBA as a reference point. I use two case studies to shed more light on this issue. Sections 2 and 3 study the economic underpinning of two decisions to build an interconnector in Europe: NorNed between the Netherlands and Norway, and the East–West Interconnector between Ireland and the UK. These cases were selected since they are published (in English) in more detail than other cases, allowing a detailed analysis.[8] The aim of this article is to critically assess the argumentation used to support the investment decision in these two cases, using CBA as the reference point to establish the effects of the investment on economic welfare. Section 4 discusses the lessons for evaluating investment decisions in international interconnections in general and offers recommendations for further research.

2. NorNed

In 2004, the Dutch regulator approved a plan by the Dutch TSO (TenneT) to build a cable from Norway to the Netherlands (hence 'NorNed') and to finance it with past interconnection auction revenues.[9] This cable has been operational since October 2008. The figures are, unless stated differently, from the energy regulator (then DTe, now EK; DTe, 2004) and TenneT (2004) and reflect the Dutch side only.[10]

NorNed is 580 km long, with a capacity of 700 MW and operates at 400 kV. TenneT is not vertically integrated with production, distribution or supply, and is fully state-owned. The Dutch and Norwegian TSOs (Statnett) share costs and revenues on a 50–50 basis. The TSOs buy power on the day market in the country with the lowest price and sell it on the market in the other country.[11] Price differences can exist because (i) the Norwegian demand pattern is flatter over the day than the Dutch; (ii) the countries use different production technologies (hydropower in Norway and thermal based in the Netherlands); and (iii) unexpected shocks, such as power plants failing unexpectedly, may occur. Table 1 shows the main costs and benefits. The overall outcome will be discussed further on under Section 2.6.

[7] Related, reliability requirements impact the trading possibilities over a line (Kirschen and Stribac, 2004).

[8] Publishing decisions in detail are not required in Europe (it is in Australia, see AER, 2007), so when it happens voluntarily it should be applauded. For example the CBA of 30 new connection by Nordel (2008) is published less detailed.

[9] In the Netherlands past auction revenues are earmarked for new congestion-relieving investments (Article 6.6 of the EU regulation also allows rate reductions; EC, 2003). Two dangers are associated with this. First, if investments are made only if enough funds are available from past auctions, otherwise underinvestment may arise. Second, it may lead to overinvestment if investments are made because there are funds from past auctions. There is no indication that either occurred here.

[10] The Norwegian analysis is not discussed since it has not been published (in English). Most likely the Norwegian analysis strongly resembles the Dutch analysis since TenneT's analysis is based on studies jointly commissioned by both TSOs.

[11] Direct market coupling proved to be difficult due to differing closing times of the Dutch and Norwegian power markets.

To facilitate comparison with Section 3, Table 1 also contains the characteristics of the East–West interconnector.

2.1. The decision criteria

DTe (2004, §52–54) looks at many different criteria, such as cost and benefit for TenneT and grid users, the effect on security of supply, the effect on consumer and producer prices, the possibility of materializing the benefits through market coupling and the benefit to consumers.[12] These criteria partly overlap and may also partly contradict each other because it is unclear how they are weighted. Altogether, the main decision criterion seems to be a social cost-benefit analysis (§53–98). A CBA for the Netherlands and one for electricity customers were made. The last had to show that users are getting a good return from the investment.

In the Netherlands, for large-scale governmental investments, a guideline (Eijgenraam et al., 2000) and subsequent improvements are mandatory (Ministry of Transport, 2004). NorNed also involved a government decision whether to invest. It is therefore useful to discuss the investment decision in NorNed using the government CBA methodology as a point of reference. This case study shall show that the NorNed approach differs in several aspects (for example with respect to the discount rate used)[13] and concludes that the CBA analysis of NorNed can be improved to better understand the effects of this specific investment on economic welfare.

2.2. Alternatives

DTe compared investing in a 600 MW or a 1200 MW cable versus not investing at all. Other alternatives were not considered, in part because the time available to change the plans was limited due to the expiration of a crucial environmental permit, which would have caused years of delay and serious additional costs. Another reason is that DTe was not allowed to alter the proposal significantly, for example by conditionally approving a much larger capacity. However, considering the right alternatives is an important part of achieving the correct outcome for a CBA. Also DTe did not compare the interconnector with an investment in generation. The TSO is not allowed to invest in generation; however if the TSO does not invest in the interconnector the market may decide to invest in generation.

2.3. Calculating the welfare effects: uncertainty and the endogenous response of companies

TenneT calculates an annual Dutch welfare gain of approximately €2 million, that is an increase in the consumer surplus of €47 million per annum and a loss for producers of €45 million per annum. DTe (§92) holds that the precise distribution between consumer and producer surpluses is particularly uncertain, partly because the models used to calculate these amounts are not specific to this and the decision to invest may change the investment behavior by market parties. However, DTe claims that the net welfare change (€2 million) depends less on these assumptions, and therefore DTe uses it (§90–92). This poses two crucial questions. First, if the models are not suited to calculating consumer and producer surpluses, how can they be used to calculate the revenues from trade? All three concepts depend on the same price, marginal cost and marginal benefit curves. Second, how do the producers react to the reduction of their

[12] Both companies and households.

[13] Neither do other appraisal guides (like EC, 2008a, 2008b) seem to be used.

Table 1
The NorNed and East–West interconnectors.
Sources: For the Dutch case: TenneT (2004, tables 4.1 and 5.1). For the Irish case: EirGrid (2008, p. 4).

	NorNed (Dutch effects only)	East–West (Irish effects only)
Investment cost (discounted to the moment of decision)	€264 million (half the cost) (including €25 million preparation costs, which are sunk)	€595 million (total)
NPV	€175 million according to TenneT €3 million according to DTe	€350 million
Length	580 km	256 km, 185 km under sea
Capacity	700 MW	500 MW
Trade benefits, directly estimated	Gross trading margin €40.9 million annually	–
Trade benefits estimated indirectly: (i) prevented investment in generation capacity (called security of supply)	–	€40 million annually
Trade benefits estimated indirectly: (ii) reduced carbon credit payments	–	€14 million annually
Reduced wind curtailment	–	€10 million annually
Loss of power due to heating of the line	€3.8 million annually	–
Net Dutch consumer & producer surplus	€2.2 million annually	–
Dutch consumer surplus	€52.1 million annually	–
Dutch producer surplus (loss)	−€49.9 million annually	–
Other benefits: increased revenues from existing interconnectors and effect on the contribution to ETSO cross-border trade	€4.2 million annually	
Other costs: operational cost and additional cost to the rest of the grid	−€3.3 million annually	
Security of supply: reserve capacity and reduced need for carrying reserve	€0.5 and €3.3 million annually	€2 million annually
Discount rate (%)	9.0	5.63
Time horizon	40/25 years	30 years
Alternatives studied	No interconnector, 600 MW (later optimized to 700 MW), 1200 MW	
Effect on competition	Mentioned, not quantified	Mentioned, some calculations, not included in the calculation
Dynamic effects	Mentioned, not quantified	Partially included, prevented investment in Ireland. No reaction in the UK, nor change in production mix
Environmental effects	Mentioned, not quantified, and likely to be small	Reduced need for wind curtailment

Notes: The difference between the consumer and producer surplus is the change in dead weight loss. This is small (€2.0 million), since the price elasticity of electricity is low. SKM Energy Consulting (2003) used a step-wise linear demand function with differently shaped demand curves per country. NorNed: yearly effects refer to 2008. The energy regulator did not include all small effects in the analysis. This is not discussed here. East–West: yearly effects refer to 2011.

surplus by €45 million annually (a present value of €550 million, at 6.8% over 40 years)? Unless they make excess profits that disappear due to the new interconnector, they have to react to stop themselves from incurring losses and going bankrupt by change in investment plans (building fewer or different power plants). Changing investment plans changes the marginal cost curves used to determine the trade revenues and the welfare effects. Although DTe acknowledges that the cable may lead to different investment patterns, the impact of this on welfare has never been analyzed. More investment in Norwegian hydro-generation could increase the social benefits of trade, because it would allow a technology mix that was previously impossible.[14] However, trade benefits might also decrease over time. Investment in a high-price area may reduce an interconnector's initial trade revenues.[15] To sum up, the direction of this effect could be either positive or negative. Determining this effect requires a separate study, which is lacking.

2.4. The effect of the interconnector on competition and the efficiency of generators

Existing electricity market models only take static efficiency into account without studying long-term dynamics (dynamic efficiency). Another, rough approach would be to look at other studies that either measured or estimated increases in efficiency due to an increase in competition. This approach has been followed by CPB and SEO (see de Nooij and Baarsma, 2009) in the Dutch debate on ownership unbundling the distribution network companies. In that debate, a 0.375% increase in the efficiency of the generator (annual turnover €5.9 billion) amounts to a benefit of €22 million annually. A similar benefit here would provide a present value of €259 million (40-year, 6.8% real discount rate). Admittedly this is a crude approach, with the risk that the competition benefits are estimated too high. The alternative is to implicitly assume that these effects are zero.

2.5. Effect on security of supply

DTe (2004, §97–98) took into account a positive but not quantifiable effect on security of supply. If the Netherlands should have an unexpected shortage of generation capacity, NorNed could be used to import extra electricity to solve the shortage. A shortage can exist when cooling water is scarce (as in the summer of 2003) or if power plants fail unexpectedly. A shortage will have

[14] Fehr and Sandbråten (1997) discussed the impact of trade between a hydro and a fossil fuel system on the investment in generation capacity. Under unrestricted trade, and with hydropower having the lowest marginal cost, overall thermal capacity is reduced and the technology mix is more centered around medium-cost technologies. Net exports from the hydro system necessitate the expansion of the energy capacity of that system (water-inflow capacity).

[15] In 2006 TenneT and RWE published a joint study of a new interconnector that will increase import capacity in the Netherlands from Germany by up to 2000 MW (export capacity will not increase due to higher transit levels through the Dutch–Belgian border). This line would cost both of the TSOs involved about €70 million. A few years later, there is a substantial chance that the extra import capacity is not going to be used often given the Dutch investment boom in generation. See Moran (2004) for a similar observations of several Australian investment plans.

two effects. First, power prices rise, and thus the interconnector will be used for import already. This effect is included in trading revenues. Second, if the shortage occurs at short notice, reducing demand or importing power may be the only solution. Such an outage has never occurred in the Netherlands, but assuming a shortage-of-supply-induced outage every 20 years, which only NorNed could prevent, over a period of 2 h (during which time other production can be ramped up, or large users can be called off line), assuming the full capacity of the line (700 MW) and a value of lost load of €8.6/kWh (see de Nooij et al., 2007), then the expected benefits are €0.6 million annually, or a discounted €7.2 million (40 years, 6.8% real). Given that such an outage has never occurred, and given that Norway has to be able to produce and transport more, and given that other preventative measures are possible (such as interruptible contracts with large users); this value seems an upper limit. Without quantification, the welfare effects of security of supply may easily get too much attention.

2.6. *The discount rate*[16]

The discount rate used in the present value calculations was debated heavily between TenneT and the regulator (see DTe 2004, §68–71; TenneT, 2004), but the discussion was unusual for several reasons. First, the discount rate used here differs from the standard discount rate used by the government in its CBAs. Therefore, a project's approval may depend on which government's department has to approve. For government investments, a 4% rate (since then lowered to 2.5%) plus a project-specific risk premium should be used.[17] Here the discount rate would be 8.9% ($4+0.9\times3+2.2\%$ inflation).[18]

Second, TenneT corrected its calculations for corporate taxes, which is logical for a company since taxes paid are a cost. It is not correct in a CBA since for society taxes are a transfer (from a company to the government, which is part of the society). TenneT proposed an after-tax discount rate of 6.31%, which divided by 1 minus the tax rate (34.5%) gave a pre-tax discount rate of 9.65%. By correcting for taxes the calculated social welfare of interconnector investment will be too low.

Third, DTe does not take costs and benefits after 25 years into account. DTe chose this shorter time horizon for two reasons (DTe, 2004, §65–67). First, the technical life of the cable is uncertain; there is not enough experience with underground HVDC cables to be certain of a 40-year life. Second, economic revenues after 2020 are uncertain since the economic models are less detailed after 2020 than before that time. A higher discount rate (or taking only a share of the expected benefits into account) after 25 years seems reasonable given these uncertainties. However, an implicit discount rate of infinity seems too extreme. Furthermore, DTe increased the cost of investment by 20% since many public investments in the Netherlands in previous years saw considerable cost overruns.

Table 2 illustrates the result of the different discount rates. 'Correcting' for the tax rate makes a big difference in NPV (compare rows 1 and 2). The difference between the government discount rate (row 5), the 'corrected' discount rate (row 2) and the discount rate used by DTe (row 3) is modest. However, the methods used to calculate the discount rate are very different and in the future larger differences cannot be ruled out. The 20% increase in investment costs and DTe's reduction of the period to 25 years instead of 40 makes a significant difference (compare rows 3 and 4). Being more cautious than the usual Dutch standards negatively impacts on the evaluation of NorNed. Although it does not alter the final conclusion for this investment, it could make it more difficult to use these more positive but standard assumption for the next investment.

2.7. *Conclusion*

Overall, there are lacunas in the economic argumentation for the NorNed case. The revenues from trade, which in the short term will be realized, will not be fully realized in the long run after the producers have adjusted their generation portfolio. These benefits from trade will not disappear completely because NorNed offers the Netherlands good access to flexibility. But in total the benefit from trade is overestimated. On the other side are savings on investments and benefits from increased competition, which have been neglected.

Several lessons can be learned for future investment. First, alternative options and the counterfactual have not been studied in detail. This is partly understandable, but it also carries the risk that better options are ignored. Second, the criteria used in the decision should be clear. If seven aspects are included it should be made clear which ones will prevail or be the most decisive. The main one seems to be a CBA, but that is not certain. Third, dynamic effects should be taken into account by studying system dynamics. Producers will react to an annual decrease in producer surplus of €45 million. Fourth, valuing effects where possible improves the analysis. Using back-of-envelope calculations may be inevitable, although more substantiated methods are preferable. Currently, the effect on security of supply seems to be overemphasized, while the effect on increased competition seems undervalued. Fifth, it is strange that the government discount rate is not used. This may create a bias in favor or against projects within the government; the discussion over the discount rate also absorbed a great deal of attention and resources. That being said, compared to other investments in the Dutch Grid, the NorNed decision stands out for being discussed and published in greater detail, even though some of these other investments exceed the costs of NorNed by far (see de Nooij, 2010).

3. The East–West interconnector from Ireland to the UK

The Irish TSO (EirGrid) is planning the construction of a new interconnector with the UK, known as the East–West interconnector. It is due for use in July 2012, will have a capacity of 500 MW and will cost €600 million. It has a total length of 256 km, of which 185 km are under sea. The Irish Commission for Energy Regulation (CER) has approved the project based on EirGrid's 'Approval to Proceed' submission in February 2009. The Irish Government gave final approval in March 2009. It will be a regulated asset owned and operated by EirGrid. The investment will be recouped through customer Transmission Use of System charges (and congestion charges should the interconnector be congested) (SEM, 2009, p. 10). The EU contributed a €100 million grant to speed up construction (EC, 2009). The studies and discussions on whether to build this interconnector lasted 30 years (DKM, 2003, p. 4), culminating in the so-called business case in 2008. Normally a business case only includes an investor's costs and benefits; however, EirGrid also included social benefits, making it more of a CBA than a business case. The third column in Table 1 summarizes the business case.

[16] In the reports, this discount rate is often referred to as the weighted average cost of capital (WACC). Since this discount rate is also used for future consumer surpluses the term 'discount rate' is used here.

[17] Project-specific risk should be valued at beta times 3% with unknown betas equal to 1 (Ministry of Transport, 2004).

[18] 0.9 risk was estimated by TenneT. Normally Dutch CBAs are in real terms. Here inflation had to be added since TenneT and DTe increased all numbers by the rate of inflation.

Table 2
Impact of different discount rates on the net present value (€million, time horizon of 40 years unless otherwise noted).
Sources: Row 2 TenneT (2004); other NPVs author's calculations based on DTe (2004) and TenneT (2004).

		Discount rate (%)	NPV
1	TenneT's discount rate before tax	6.31	448
2	TenneT's discount rate after tax	9.65	175
3	DTe's discount rate, cost and time horizon equal to TenneT's	9.00	213
4	DTe's actual calculations, high cost and short time horizon (as used in the decision)	9.00	3
5	Government's discount rate (infinite horizon)	8.90	220

3.1. Security of supply

Security of supply has been measured through the replacement need for a peaking plant. The Generation Adequacy Report (made earlier by EirGrid) has identified the need for additional generating capacity or an interconnector over the next 7 years to maintain security of supply. At the same time, they signal significant capacity available in the UK. The UK capacity is expected to increase further, resulting in a capacity margin of 35%. The excess capacity in the UK enables it to trade electricity across borders.

In 2007, total installed capacity in Ireland was 7577 MW, of which 1132 MW was not fully dispatchable (mostly wind, 950 MW). Installed capacity is expected to increase to 9081 MW, of this 3076 is not fully dispatchable (wind energy accounting for 2800 MW). Since plant closures will exceed new capacity, fully dispatchable capacity will decrease from 6445 to 6005 MW. In the UK, EirGrid expects total installed capacity to increase from 78.4 GW in 2007 to 101.9 in 2013. The largest increase will come from new gas-fired generation. The growth in wind energy will add a further 9.3 GW. For the UK, IerGrid looks only at the total capacity and does not distinguish between fully and not fully dispatchable capacity. This means there is a greater reliance on not fully dispatchable capacity in the UK than the not fully dispatchable energy Irish capacity. This might overestimate the possibility Ireland has to import electricity and to avoid investing in a new plant.

EirGrid estimates the benefits from this capacity margin in the UK to be enough to save a peaking plant. The costs of a new peaking plant are estimated at €39.9 million annually (500 MW times €79.77/kW as the annual fixed cost of a best new entrant peaking plant). Furthermore, EirGrid notes that such a plant generally has low energy efficiency (it operates only a few hours per year and has to be ramped up and down quickly).

EirGrid (2008) assumes the UK capacity to be so generous that the Irish economy can profit over the course of 30 years. For the short term this might be correct, but for the longer term (say after 5–10 years) this seems too optimistic. Without the cable, the UK generators would have to make an optimal investment decision, and if capacity is so abundant, its reward would be low, and investments and capacity would be reduced. For example, if UK's excess capacity falls after using the cable for 5 years, a new plant would be necessary from 2017 onwards. Then the security of supply benefit would disappear and the present value of all benefits would fall to €543 million, which is €50 million less than the cost. Alternatively, if the UK generators decide to invest to cope with Irish demand over the East–West interconnector, they do so because they get paid for it: the Irish pay for the extra capacity (via the electricity price), even though it is standing in the UK and not in Ireland. So also in that case it is not a cost saving either.[19]

[19] This could be a cost saving if the UK has a comparative advantage (for example because the UK can use a technology the Irish cannot use, like in the NorNed case the Norwegians use hydropower which for the Dutch is impossible). Since both countries use gas and coal technology and import part of these fossil fuels a comparative advantage for the UK seems absent.

Trade is further facilitated by the fact that demand peaks and forced outages in the Republic of Ireland and the UK do not coincide (EirGrid, 2008). Ireland's peak demand in 2005 occurred in mid-December, while UK peak demand occurred towards the end of January. However, the correlation between the demand curves of Ireland and the UK was 0.89 in 2005 (Malaguzzi Valeri, 2009). Modest savings in required capacity are likely, but have not been quantified.

3.2. Competition

Lack of competition is a real problem in the Irish market, since it is highly concentrated. Furthermore, plant availability in Ireland was only 80%, while the best practice rates available are about 90%, suggesting that competition is too weak to make the generators produce efficiently. The new interconnector will improve competition in the Irish market (EirGrid, 2008, p. 4 and 10). Currently the Residual Supply Index is over 1.1 for around 50% of the time. With the new interconnector this is expected to improve to 67%. According to Malaguzzi Valeri (2009), a rule of thumb for electricity markets is that the RSI should be above 1.1 for 95% of the time, which would require an increase in interconnection capacity of 1300 MW or more. As EirGrid (2008, p. 10) states, one of the key financial benefits associated with increase in competitiveness is increased pressure on the efficiency of generators and reduced market power, creating a downward pressure on prices. They estimate that every 1% decrease in average wholesale electricity prices creates a benefit to consumers of €20 million annually. It is unclear whether this €20 million is a transfer of wealth (through lower mark-ups) or a welfare increase (because generators become more efficient). Second, an alternative method of increasing competitiveness without a new interconnector would be to split the dominant supplier: the incumbent has an 80% market share. Given that it is 95% state-owned (Malaguzzi Valeri, 2009), this may not be so hard to do as for private companies (however political economy will make it difficult or impossible as well). EirGrid did not quantify the expected price decrease, nor how much of it would be an efficiency gain. Third, it is unclear whether the benefits of a lower price through more competition and reduced investment needs are mutually exclusive, since the capacity replaced by the line is not additional, but replaces a generator that will not be built (see also the discussion of Borenstein et al. (2000) in Section 4).

Despite these questions, the competition benefits appear to be real. The fact that they are not included leads to an underestimation of the total benefits.

3.3. Reduced wind curtailment

Ireland plans to invest substantially in wind energy. Given the fluctuations in the amount of wind energy actually produced, wind energy will sometimes have to be curtailed if it constitutes a large fraction of the total generation capacity. A new interconnector reduces that need through pooling with the UK. IerGrid estimates this to be worth €10 million annually, but does not give details of its calculation. However, this number is partly based on the Grid Development Strategy with the 2025 target of 33% renewables. This raises two questions. First, how realistic is the scenario of 33% renewables and how fast will it be realized? (It is strange that only one scenario is used; given that wind capacity increases over time, it is more likely that the benefits would be smaller at the start and would increase gradually, which would reduce the present value of the benefits.) Second, the potential of the interconnector to prevent wind curtailment also depends on the correlation between wind conditions in the UK and in Ireland. The stronger the correlation, the less potential there will be to export wind power from Ireland to the UK and vice versa. EirGrid does not reveal whether this has been studied.

A related effect not discussed by EirGrid is that if wind energy capacity increases, thermal plants have to ramp up and down more frequently, which could reduce their efficiency and increase their costs. An interconnector could reduce this. This effect could be a real benefit, not discussed in the decision.

Therefore it is questionable whether the benefits estimated for reduced wind curtailment are accurate.

3.4. Reduced carbon credit payments

Reduced carbon credit payments (i.e. CO_2 permits) are estimated to be worth €28.30 million annually. EirGrid assumes that 1 MWh of electricity is generated with an average of 600 kg of CO_2, the 500 MW Interconnector has a 50% load factor and a CO_2 price of €21.57 per tonne. Given the uncertainty of whether this effect will actually materialize, EirGrid assumes a 50% likelihood and an expected value of €14.15 million (a current value of €203 million). However, if the interconnector is used to import energy, the UK generators have to buy CO_2 permits in the UK, which will have to be paid by the Irish importers, resulting in no savings. Real CO_2 reductions are derived only from a reduced need for wind curtailment in Ireland, or in the UK, or if more wind energy capacity is installed. The last two issues are not discussed, and the first is included in the cost-benefit analysis. Therefore, the likelihood that this benefit will materialize seems to be overestimated substantially.

3.5. Discounting the future/valuing governments

EirGrid uses its real pre-tax WACC of 5.63% to discount future benefits (CER, 2005). The pre-tax WACC is too high since it is used to determine how much return is necessary to compensate an investor. An investor pays the corporate tax and receives the post-tax WACC of 4.92%. The investor does not value the tax revenues of the government as a benefit. If a society as a whole is investing (which is here implicitly the case since all electricity users will pay for the investment via system charges), these tax revenues are for society a real benefit (the government can do more or the government needs less other taxes). That means that for society-wide investments the post-tax WACC is better. Using the post-tax rate instead of the pre-tax WACC increases the present value of the benefits from €948 to €1026 million. This difference is rather small due to the low Irish tax rate.

3.6. Further remarks

The required capital costs necessary for development and construction are estimated at €595 million, including contingencies. No other costs are noted; for example, no maintenance and operational cost are included. TenneT included an annual estimate of €4 million (a present value of €57 million) for the NorNed cable. The same is true of electricity losses during transport, which EirGrid does not mention.

An alternative approach to study the welfare effects of this interconnector is followed by Malaguzzi Valeri (2009), who studies trade benefits and the cost of generating electricity using the merit orders of 2005 for Ireland and the UK. This approach is comparable to the NorNed approach. Trade benefits are largely based on the fact that the price-setting generation in the UK is mostly coal-fired, while in Ireland it is gas-fired. Different CO_2 prices and different sizes of additional interconnection capacity are simulated using the 2005 data. A new 500 MW interconnector is beneficial to social welfare, but is too small to integrate both markets (a price difference of less than 1.5%). At the margin, the capacity necessary to integrate the markets (last 500 MW capacity) has more social costs than benefits. Trade revenues depend on the generation mix, which may change over time. For example, the large share of gas-fired generation in Ireland compared to the UK is strange since the Irish gas price exceeds the UK's by 20%, the UK's share of coal generation may decrease due to CO_2 prices, and an increase of wind energy in Ireland makes coal plants the price-setters more often. The trade revenues and thus the social desirability of the interconnector depend on a correctly predicted mix of electricity generation. But Malaguzzi Valeri (2009) uses a static model, and changes in the generation mix are not considered. This is especially important since the Irish producers face a drop in producer surplus of €143 million annually, to which a response is to be expected. A model of system dynamics analyzing future investment decisions is lacking here, although it is necessary for a proper CBA.

3.7. Conclusion

Several lessons arise in the comparison of the business case for the Irish East–West interconnector with the CBA approach. First, the largest benefit is an increase in the security of supply, estimated in terms of avoiding the expense of a new generator, which would otherwise be needed to maintain security of supply at the same level. Imports from the UK are assumed to be always possible. However, the non-dispatchable capacity in the UK has neither been taken into account, nor has the fact that UK generators will invest less to reduce abundant capacity, reducing the possibility for low-cost imports. Second, competition benefits were cited as important, but are not quantified. Third, the benefits of reduced wind curtailment are crucially dependent on new investment in wind energy and the extent to which the system can handle it, as well as the correlation between wind in Ireland and in the UK. Fourth, the business case overestimates the benefits of reduced carbon credit payments on imported electricity because now the Irish power importers will have to buy these permits in the UK instead of in Ireland. Fifth, the discounting seems to be too negative; the social benefits are calculated using the pre-tax WACC instead of the post-tax WACC. Sixth, the calculation available is less detailed than the one available for the NorNed cable. But like in the Dutch case, the interconnector investment is published in more detail than domestic investment although this latter requires more money.[20] The main conclusion is that EirGrid's conclusion that the East–West Interconnector is socially attractive does not stand up to scrutiny, the true conclusion could be negative instead of positive.

4. Conclusion and policy and research recommendations

Investments in transmission and interconnection capacity require substantial amounts. Claims are that the coming years

[20] The Irish National Development Plan finds that over €1.2 billion in investment is needed for the strategic energy infrastructure (EirGrid, 2008, p. 1).

substantial investments are necessary to allow for more trade, to stimulate competition and to connect renewable energy to the grid. A good and thorough analysis of the costs and benefits of proposed investments is therefore important to make sure that only investments that increase welfare go ahead. This article investigates the economic arguments made for two decisions to build an interconnector in Europe, and finds that the cost-benefit analysis used can and should be improved to ensure efficient and adequate investments.

First, in a CBA, the demand for a new investment must be clear before it can be evaluated. Currently demand for new capacity is unclear: utilizing the current connections can be improved (for work on that, see ERGEG, 2009) and the measures of congestion have to be further improved. Measures of interconnector scarcity are crude and often do not use economic concepts. Measuring congestion is difficult; there are several different measures each with pros and cons, see ERGEG (2009) and CWRI (2010) for a discussion of the different metrics and quantifications. Measuring demand for interconnectors is difficult can be illustrated by comparing two measures: the hours a line is (contractually) congested and the price paid for capacity over that line. EC (2007a, p. 172) studies the first metric and finds that many interconnectors are congested. Other indicators show for the same line no congestion. For example the interconnectors from the Netherlands to Germany were congested 62.9% of time and from Germany to the Netherlands congestion existed 87.9% of time from January until May 2004. Under this definition, a line can be congested in both directions simultaneously, even though electricity will only flow one way and it is not actually desirable for it to flow in both directions. However, the monthly auction prices showed a different picture. The price paid to export from Germany to the Netherlands was with 6.66€/MWh substantial. The price for the reversed was a mere 0.08€/MWh (about 0.2% of the wholesale price), indicating that there is hardly any congestion because market participants are unwilling to pay for capacity (see de Nooij, 2010).[21] Congestion within European countries is even harder to quantify than border congestion because market design is such that price differences inside European countries do not exist (with the exception of nodal pricing in the Scandinavian countries).

Second, in both CBAs the TSOs and regulators involved went to considerable lengths to make the best decisions. However, in both CBAs their argumentation is flawed. The NorNed case underestimates the social benefits of the investment, while the East–West interconnector overestimates these benefits, to the extent that the true conclusion could be negative instead of positive. Possibly regulators may try negative assumptions in their CBAs to be sure that the NPV remains positive. A drawback is that it is not clear how attractive interconnector investments are, resulting in inadequate attention. Also it is not unthinkable that a new benchmark approach is set, which is unnecessarily negative for the next investment.

Third, both CBAs do not take the (long-term) reaction of producers to new interconnection capacity into account and both ignore some of the potential benefits of more competition. Short-term trade benefits are calculated in great detail. The efficiency gains in generation, which are brought about through increased competition, are mentioned but not quantified, leading to a potentially significant underestimate of the welfare effects of investment in interconnectors and transmission. It is unlikely that these effects can ever be calculated to the degree of detail that the current trade benefits are estimated, but the current implicit approximation of zero benefits could certainly be replaced by a crude, but more correct estimation (probably a bandwidth).

In both CBAs , dynamic effects are to be expected, but these are not included in the discussion. Generators will respond to a lower calculated producer surplus and to additional supply arriving over a new interconnector by changing their investment pattern. This may create social benefits (fewer investments lead to a lower social cost by definition) and impact trade benefits as well.

Fourth, several smaller issues can also be improved. For example, both cases discount using a pre-tax WACC, which underestimates the benefits for society since it ignores tax revenues as a benefit. In both cases, only a limited set of alternatives is examined, and a potentially better alternative is likely to be missed. Some difficult to value effects are not quantified or valued, such as security of supply in the Dutch case. A rough valuation provided here shows that this is a minor effect at best.

Fifth, both economic argumentations differ widely, leading to situations in which approval for an investment may depend on which authority or country has final approval. The development of a uniform method used for all transmission and interconnector investments in Europe, or within a particular country (used for all government-approved CBAs), would help to reduce this. A standard method would limit some of the choices now left to the applicant (such as the choice of discount rate) to save time and costs on standard issues, which could then be spent on more difficult issues (such as predicting generator responses). One guideline may also make evaluations by the regulator more predictable. For guidelines inspiration can be found in national or EU guidelines for infrastructure investments (e.g. Eijgenraam et al., 2000; EC, 2008a) or in international guidelines for transmission investments (e.g. in Australia (AER, 2007); in California (CAISO, 2004); Awad et al., 2004). Of course a guideline still leaves a lot of aspects to be determined or quantified by the applicant and errors are still possible (Littlechild (2004) criticized an Australian decision for taking insufficient alternatives into account).

Sixth, in both countries the interconnector decision receives more attention and a more detailed analysis of costs and benefits than the domestic grid investment even though these domestic investments require substantially more money. This may not lead to optimal investments.[22]

It is therefore unlikely that decisions to invest in interconnectors and transmission in Europe are currently maximizing social welfare. Both underinvestment and overinvestment can occur, and both are costly.[23]

4.1. Research recommendations

Some of these critics can be dealt with in new CBAs; however two effects of interconnectors deserve more research.

The first effect that deserves more researched is the dynamic effect. Connecting two grids may reduce the need for generation capacity if peak demands are not closely correlated. Change in investment is to be expected due to different price patterns, in

[21] Other congestion measures, such as the 10% of demand as a minimum required import capacity agreed upon in Barcelona in 2002 (see EC, 2007a, p. 175), lack any economic rationality. It may be too little in some circumstances and too much in others (CEER, 2003). For instance, the Dutch interconnector remains congested though import capacity is 17%. Léautier and Thelen (2009, p. 140), using four different congestion metrics, show that in a three-node network the congestion costs for different sizes of a new interconnector vary widely.

[22] Two (speculative) explanations for the relatively high interest in interconnectors: (i) regulators may fear that the other country would benefit more from an interconnector at the cost of domestic consumers; and (ii) alternatively, interconnectors may be easier to analyze and thus get more attention.

[23] For discussions on whether over- or under-investments are more likely or worse, see de Nooij (2010), Nordel (2008, p. 3, 19), Brunekreeft et al. (2005, pp. 75–76) and Léautier and Thelen (2009, p. 133).

part from lower investment in peaks and probably more in base loads, and location can change. For NorNed, this would probably lead to greater benefits, while for the East–West interconnector it would probably lead to lower benefits. The amounts involved are potentially large: if every MW of interconnector capacity leads to a 0.5 MW reduction in generation capacity the additional benefit can be in the magnitude of half the investment costs. One could argue that this effect does not need to be included because the generation mix takes a long time to change given the long lifetime of power plants. However, not all power plants need to change. If the next investment changes (type, whether it is built, location, etc.), this is already a substantial effect. Also the Californian ISO recommends that the interaction between generation investment, demand-side management and transmission investments is taken into account (CAISO, 2004). However, only a few papers study the interdependence between transmission and generation. One exception is Sauma and Oren (2006),[24] who show that the size of the welfare gains associated with transmission investments and the location of transmission expansions may depend on whether a generation expansion response is taken into consideration.

The second effect that deserves more research attention is the effect of interconnectors on competition between generators. In EU policy, this is an important reason for new investment, but in the CBAs studied this effect was not included. Most electricity market models estimate allocation efficiency and production efficiencies resulting from trade, given the current technologies and prices.

In the theoretical literature, much emphasis is put on the reduction in market power due to interconnector investment, resulting in lower mark-ups over the price, smaller transfers from consumers to producers and a lower dead-weight loss (see, for example Borenstein et al., 2000; Léautier, 2001; Tanaka, 2009). In practice, estimating the reduction in mark-ups is difficult, and it is not included in the cost-benefit analysis found, leading to a likely underestimate of the benefits (Nordic Competition Authorities, 2007, pp. 49–51).[25]

Note that trade benefits and lower mark-ups may interact. Borenstein et al. (2000) model two identical markets with a monopolist. With a small interconnector, one of the monopolists could play aggressively and export the full capacity of the interconnector. For the other monopolist it would still be attractive to exercise monopoly power over the residual demand in its home country. With a larger interconnector the monopolist facing imports would find its best strategy to react aggressively and export power. From his perspective this strategy maximizes his expected profits. The result is that for symmetry reasons, both companies act as duopolists. Prices and quantities produced and sold would be similar and thus the interconnector remains idle. The counter intuitive result is that the competition effects may be the greatest when the interconnector is not used. So unused capacity may appear to be overbuilt and underused, but could actually provide a useful antidote to anticompetitive behavior.

Apart from lower mark-ups, competition can improve x-efficiency and the dynamic efficiency of generators due to stronger incentives to be efficient. Although this effect is mentioned in the policy claims that Europe needs more interconnectors and transmission capacity, it has never been included in a CBA. Ahn (2002) finds that these long run effects of more competition often exceed the short run effects. This is in line with Joskow's (1997, pp. 124–125) expectation that competition (through market liberalization) will not lead to significant short-run cost savings. He expects more benefits from medium-run efficiency gains because competition may reduce the existing large differences in the operating performance of the existing stock of generating facilities and increase labor productivity. (The differences in operating performance exist even after controlling for age, size and fuel attributes.) Joskow expects the main benefits to come from cost savings associated with long-run investments in generating capacity, where controlling for the relevant characteristics, investment costs vary widely between companies, as well as adoption speeds for new technologies. Joskow expects the most from x-efficiency and dynamic efficiency. Until x-efficiency and dynamic efficiency are included in CBAs, the welfare contribution of new investments will be underestimated, potentially resulting in too little investment.[26]

4.2. In conclusion

Given the amount of proposed transmission investments by ENTSO-E (2010) and others, further thinking about the costs and benefits of these investments seems a worthy goal, especially since each investment is decided upon separately, usually after a cost-benefit analysis is performed. Some practical and theoretical challenges exist, both for the TSOs and the regulators involved and for the academic world. This paper has endeavored to contribute to that thinking; however, it is unlikely that a perfect CBA method which both TSOs and regulators can use will be found. Some of the issues at stake are too complicated for that. Including some of the effects with a bandwidth would seem to be the best that can be achieved. That requires careful drafting of the CBA since policy makers are not used to work with a bandwidth, and might use the most likely average or one of the borders if that is more attractive. If the most likely outcome is used instead of the bandwidth than uncertainty, it might not be dealt correctly. However, not including a value (or bandwidth) for an uncertain effect requiring more research is in political decision making implicitly equal to using a value of zero.

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[24] Other exceptions are Keller and Wild (2004), CAISO (2005) and Ojeda et al. (2009). Fehr and Sandbråten (1997) analyze changes in investment due to interconnection.

[25] For the Great Belt interconnector between East and West Denmark the Danish TSO estimated the welfare contribution of increased competition to yield up to 20 m€/year in socio-economic benefits (Nylund, 2009). Given this uncertainty they chose not to include it in the cost-benefit analysis at all, although they do suggest that a careful alternative is to include 10–20% of it.

[26] For a further elaboration on these long run effects, see de Nooij (2010).

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