booz&co.

FINAL REPORT

BENEFITS OF AN INTEGRATED EUROPEAN ENERGY MARKET

Prepared for:

Directorate-General Energy
European Commission

Booz & Company, Amsterdam

Professor David Newbery, University of Cambridge

Professor Goran Strbac and Danny Pudjianto, Imperial College, London

Professor Pierre Noël, IISS, Singapore

LeighFisher, London

Revised 20th July 2013

Table of Contents

EXECUTIVE SUMMARY

GAS MARKETS

Greater integration of the gas market will likely produce important economic benefits from price effects and from increased security of supply.

Under a scenario in which the current situation of oversupply continues, market integration could facilitate a maximum benefit from price effects – price of gas, and price of flexibility – of up to €30 billion per year for the EU27. In addition, we have demonstrated that several of the EU27 countries are already enjoying the benefits of market integration. As further markets within the EU mature in terms of market liberalisation and integration, more member states will be able to experience similar benefits. Whilst our analysis has concentrated on wholesale prices, based on import border prices, market integration can also lead to more players entering end-user markets and thus increasing competition within national markets. While this may generate additional price pressure in retail markets and thus additional economic benefits, the present study has not assessed these effects.

For market integration to occur, sufficient available connecting infrastructure between markets is necessary, in combination with the supporting regulatory and political conditions to foster trade. Additional connecting infrastructure reduces the dependency of markets on a limited number of sources of supply, and can therefore improve a market's security of supply. We have assessed the impact of such an improvement in security of supply in terms of a reduction of GDP at risk caused by a significant supply outage. We find this differs significantly across countries, and is dependent on a market's dependence on gas and the absolute levels of GDP.

We assume that when the European market is fully integrated, all EU27 countries should enjoy an "N-1" security of supply situation. To achieve an "N-1" security of supply across all EU27 member states, an estimated investment of €1.5-3bn in supply infrastructure is required, on top of the €10bn+ investments up to 2022 reported by ENTSO-G for which a financial investment decision has been taken. We have not determined whether these extra investments are in fact necessary to achieve market integration, nor have we analysed the financial attractiveness of it, nor which parties should finance such investments.

ELECTRICITY MARKETS

During the period from 2004, the main integration initiative in the electricity market has been the implementation of the Target Electricity Model based upon market coupling, which is intended to be extended to the entire European electricity market by 2014, although there may in practice be some delay. We have estimated that the benefits of the integration due to market coupling, once market coupling is fully implemented across the EU, will be of the order of €2.5bn to €4bn per year, or about €5 to €8 per capita per year. About 58%-66% of this benefit has already been achieved due to the level of market coupling already present, especially in the large electricity markets of NW Europe and the Nordic region. The remaining 34%-42% will be achieved with the completion of the Target Electricity Model.

But market coupling is delivering only the benefits of short term arbitrage in energy trading. The Target Electricity Model only makes partial progress in delivering a fully integrated electricity market. A fully integrated market would facilitate the short and long term trading of energy, renewables, balancing services and security of supply without regard to political boundaries. We have found that much larger gains can be obtained if the market is truly integrated, which would require the adoption of much deeper market methods of integration, such as the use of Financial Transmission Rights.[1] We have assessed only the technical gains, further gains could come from the effect of increased competition in generation which would be facilitated in a properly integrated market.

In €bn/year (rounded)	2015	By 2030
Integrated	10.0 to 16.0	12.5 to 40.0
Reduction for 50% less TX investment	-3.0 to -3.5	-3.0 to -5.0
Reduction for self-security	-1.0 to -3.0	-3.0 to -7.5
Extra for shared balancing	ca 0.1	0.3 to 0.5
Extra for Demand Side Response	0.5 to 1.0	3.0 – 5.0
Extra for Coordinated RES investment	n/a	15.5 to 30.0

Figure 1: Summary of the net benefits of market integration from 2015-2030, taking into account the variety of scenarios studied

In Figure 1 we summarise the net market integration benefits that could be achieved, in round figures. €1billion per year translates into €2 per capita per year, so a simple conversion from the figures in the table above to per capita figures is available if desired. The 2015 figures indicate what could have been achieved if markets had already been fully integrated, although plainly on that timescale that will not happen. The 2030 figure shows how that can grow over the following 15 years if in fact market integration is achieved.

The first line of the table shows the net benefits of achieving basic market integration. Each further row shows the adjustment that should be made to that for each of the conditions mentioned. These can be added up if more than one applies. It can be seen that integrating the market delivers the largest benefits, in the range of €12.5bn to €40bn per year by 2030. At the upper end, around 90% of the net benefits will be achieved even if the increment in transmission capacity is only half of what is optimal. A similar reduction in benefit would apply if countries seek to achieve security (adequacy) of supply at a national level. Some modest benefits would come from sharing balancing reserves. And material gains of the order of €4bn could come from using smart grids to facilitate demand side response at the consumer level. Large gains of €16bn-€30bn are available if there is a true common market for renewable energy as envisaged by the Renewables Directive. This will be achieved by making it commercially desirable to locate renewable generation capacity in locations that are most effective for it. If this in fact happens, the transmission required to support it will be in substantially different locations from otherwise, and increased quantities are required.

[1] *See "Physical and Financial Capacity Rights For Cross-Border Trade", 2011, Booz & Co, D. Newbery and G. Strbac, available at http://ec.europa.eu/energy/gas_electricity/studies/electricity_en.htm*

Achieving this will require tough political decisions to be made. Political buy-in from member states so that they will be willing to facilitate this level of integration requires them to have confidence in the integrated market to deliver the energy and security of supply their constituents desire, as they would if they were representing just a small part of a larger country, thus to break out of the self-sufficiency mind-set that most countries still retain.. Energy markets, renewables markets, and capacity markets need to be truly international if cost savings are to be achieved while maintaining security of supply and renewables targets. However once embarked upon it is a route of low regret. The benefits are large and relatively insensitive to different market scenarios. Incidence effects are driven by the terms of trade, and mechanisms are available to protect negatively affected parties at member state level, if national governments choose to employ them.

Full integration will require large investments in transmission capacity, albeit not much larger than is already desirable without it. But this is much cheaper than the alternative of further investment in generation capacity. The ENTSO-E plan of a 40% increase by 2020 is fully adequate. However this rate of investment needs to be maintained to 2030. However use of smart grids to facilitate Demand Side Reduction will materially reduce the requirement for additional transmission capacity. But around 90% of benefits are achievable even if only half the desirable increment in transmission capacity is achieved, even without demand side reduction.

1. INTRODUCTION

1.1 BACKGROUND

Booz & Company in association with LeighFisher, Professor David Newbery (University of Cambridge), Professor Goran Štrbac and Danny Pudjianto (Imperial College, London), and Professor Pierre Noël (IISS, Singapore) present this revised final report on "Benefits of an Integrated European Energy Market". This was procured by the European Commission Directorate-General Energy as tender ENER/B1/491-1/2012 under framework contract TREN/R1/350-2008 Lot 2.

The contract was signed on 31 December 2012, and a kick-off meeting was held in Brussels on 15 January 2013.

1.2 PURPOSE OF THE STUDY

The terms of reference of the study require that we:

- Assess the benefits of the internal energy market and integration of networks. The study shall examine the benefits of the internal energy market achieved so far in the light of recent policy/legislative developments up to 2014 on the one hand and expected to be achieved by further integrating the market and interconnecting the networks beyond 2014 up to 2020/30.
- Estimate the costs of delayed integration of the internal energy market and insufficient interconnection of networks beyond 2014 up to 2020/30.

In particular, we are asked to perform a literature review, present some case studies, and devise an analytical framework in which we will then make four specific comparisons of different situations to that will elucidate the above questions.

1.3 PROGRESS OF THE STUDY

We have previously presented an interim report, a revised interim report, and a draft final report, which was subject to two revisions. A final report was produced and this is the only and final revision to the final report.

1.4 CONFIDENTIALITY

We have had access to commercially confidential data from the EC to assist in conducting this study. We have attempted to ensure that only aggregate statistics are reported on the data, thus not betraying any confidence in this report.

1.5 STRUCTURE OF THE REPORT

Chapter 2 covers the literature review. Chapter 3 covers modelling methodology, and in particular scenarios. Chapter 4 sets out our findings in relation to the gas market. Chapter 5 sets out our findings in relation to the electricity market. We provide a glossary of abbreviations and terms. Appendix A provides more detail on gas modelling methodology. Appendix B sets out in detail our study of the impact of electricity market coupling in the period 2004-14. Appendix C sets out some of the principal economic assumptions used in the electricity modelling.

2. LITERATURE SURVEY

2.1 INTRODUCTION

This chapter sets out a brief survey of literature relevant to the quantification of welfare benefits from market liberalisation and integration in the gas and electricity sectors. Market reform in the gas sector is somewhat delayed in comparison to the electricity sector, and this manifests itself in a richer range of literature for electricity. However with market integration issues only coming to the fore in the last few years, there is a particularly limited range of literature on quantification of benefits for market integration.

Given the limited and diverse range of materials available, our meta-analysis will take the form of assembling the evidence from the papers available, and summarising the conclusions where several authors have studied a similar question.

2.2 GAS MARKETS

2.2.1 *Introduction*

There is a significant body of literature available on the degree of gas market integration within and across markets, but only a very limited number of studies that go in the direction of quantifying the impact of gas market integration. When studies do attempt to quantify any impact, focus is on investigating the impact of market *liberalisation* rather than market *integration*, likely due to the fact that there are few, if any, examples where stand-alone markets have been integrated beyond the current level of integration in Europe. Research efforts focus primarily on the quantification of the impact on price and security of supply (SoS). Therefore, this literature survey on gas markets first covers the literature available on price impact and SoS. Thereafter, it makes a note of other mentioned effects (e.g. environmental factors). Finally, this survey provides an overview of the literature investigating the degree of integration within and across markets. Although this is not the direct scope of this research, it provides useful insights on the development of gas market integration in general.

2.2.2 *Price development in liberalised markets*

Some literature suggests that liberalisation of gas markets resulted in a reduction of industrial prices. For example, Copenhagen Economics (2005) concludes that industrial prices dropped by 1% across the EU in the short term, and 4-5% in the long run, based on panel data econometrics. However, liberalisation does not seem to have resulted yet in a reduction of prices at household level between 1992 and 2007 (Brau et al., 2010). A partial explanation for this can be that higher public ownership (generally in non-liberalised markets) in gas production *lowers* gas prices and is a way of keeping domestic gas prices low, whilst liberalisation does not, but brings prices in line with costs (Pollitt 2012). On the other side, Ernst & Young (2006) concludes that gas prices for consumers *are* reduced by a higher degree of competition, and fall by €0.8/GJ from a situation with no liberalisation to a situation with full liberalisation. These differences in insights regarding the impact of liberalisation on household prices exist in spite of these studies focusing on the same time period (Brau et al. 2010 investigate a period 1991-2007, whilst Ernst & Young 2006 focuses on 1992-2005), and the same region (EU15).

Ernst & Young (2006) also concludes that there is a strong link between border and consumer prices and the degree of liberalisation, particularly the unbundling and the creation of an independent TSO. For example, if a TSO is unbundled, prices in all consumer groups have fallen, with an estimated price difference of ~15% versus a situation where the TSO is not unbundled. Ernst & Young bases its conclusions on a regression analysis, which investigates the relationship between prices and a range of competition indicators (degree of market opening, percentage of market not covered by the three largest companies, and the unbundling of a market, particularly the presence of a TSO). Ernst & Young (2006) do find that liberalisation naturally results in price volatility, which they state as a "necessary facet of liberalisation and essential for incentivising investment" to ensure reliability (Ernst & Young, 2006, page 4). Nevertheless, they state that relative volatility in gas markets is less than electricity markets.

Stern and Rogers (2011) reason that price formation of natural gas prices will move away from the common oil-indexation towards hub-based prices. They see *"no commercially viable alternative to hub-based pricing in the European gas market"*, and see this paradigm shift driven by the need for one single type of price formation mechanism for all gas buyers (e.g. importers, wholesalers, end-users), instead of two (oil indexation and hub prices). Stern and Rogers expect this transition to continue in Europe and see hubs become the dominant price-setting mechanism in the majority of markets in NW Europe relatively quickly and at a slower pace elsewhere. They foresee the transition however to be difficult, amongst other things because the continental European gas hubs are relatively illiquid and lack depth. It can be argued that liberalisation, and the market integration following from there will further foster market liquidity and depth, and speed up the pace of transition to one single type of price formation. In addition, the maturity of hubs in continental Europe is crucial in credible hub price creation, discovery and reference points for hub price formation (Heather, 2012). The Gas Target Model, the vision of the EU regulators of the future gas market structure (as developed by the CEER, Council of European Energy Regulators) is seen by Heather as one of the tools that can stimulate the required liquidity and transparency to achieve this.

2.2.3 Security of Supply in liberalised markets

Ernst & Young (2006) claim that security of supply does in general not deteriorate over time with market liberalisation. Joskow (2005) agrees with this, and states that liberalisation of electricity and natural gas markets can facilitate meeting reasonable supply security goals only *as long as* the appropriate market and industry structure, market design, and regulatory institutions are developed and implemented. He claims that market integration results in significantly higher coordination for pricing, scheduling and balancing protocols for pipeline owners to make efficient use of the system for delivering natural gas reliably from dispersed production sources to dispersed consumers, which in turn can result in more frequent imbalances in the market, potentially jeopardizing security of supply. Therefore, proper market conditions have to be in place to solve for these influences. Makholm (2007) observes that effective liberalisation and continental-wide market integration in the US ensures Security of Supply for any region or city, by allowing the price mechanism to efficiently manage scarcity (demand or supply shocks). Practically, this means that local shortages are translated into pan-US price spikes. In addition, he identifies a number of specific institutional conditions for a continental-wide, inland gas market to develop and work efficiently.

2.2.4 *Other effects in liberalised markets*

Other effects of market liberalisation described in the literature concern environmental factors – however, the comments concern the energy market in general, rather than the gas market in particular. In addition, it must be said that the impact of liberalisation on sustainability when thinking about natural gas is particularly relevant for the electricity market as the emissions from natural gas are primarily generated during power generation in gas turbines. The fact that gas will play a significant role in the power generation to reduce emissions in the short and medium term is recognized by the European Commission (EC, 2011), and reemphasizes the link between electricity and gas market.

Ernst & Young (2006) suggests that the costs of compliance for environmental legislation are reduced in a liberalised market; the study claims that the process of liberalisation nurtures an ethos of discovering cheaper solutions with energy companies (more than this would have been the case if one –state owned- monopoly would play in the market). However, the actual reduction in emissions is driven by target setting, rather than liberalisation on its own (which may also be part of European Policy, but not necessary part of liberalisation efforts).

2.2.5 *Current level of gas markets' integration*

Multiple authors have studied the level of market integration within European countries, across European countries, within the US and across Europe and North America. Interestingly, they conclude that there is a high level of integration within North America, within specific European countries and across European regions, but that there is no evidence for integration across Europe. A recent study does provide some evidence for trans-Atlantic integration, based on perceived price convergence between the UK's NBP gas hub and the US' Henry Hub.

Asche et al. (2001, 2002) investigated the level of integration of the European natural gas prices at country level and concluded that both the French gas market and the German gas market were integrated within these countries already more than ten years ago. They based their conclusions on co-integration tests that showed that the prices of gas imported from different sources ("beach prices") into these countries moved proportionally over time, indicating an integrated gas market (i.e. "Law of One Price" holds). For North America, several studies conclude that the opening of transmission networks has led to convergence of prices in various locations and that natural gas markets have shown strong evidence of integration since the introduction of open access transportation (FERC Order 436) (e.g. De Vany and Walls, 1993, Walls, 1994). However, both King and Cuc (1996) and Cuddington and Wang (2005) conclude that particularly the Central and Eastern region were highly integrated (data analysed up to and including 1997) but that a single national natural gas market had not yet emerged at the time due to limited physical connectivity with the Western region.

Neumann et al. (2006) are said to be the first to have investigated the relation between spot markets for natural gas in Europe, and researched whether the process of liberalisation has led to a convergence between prices at different European trading hubs (UK's "NPB", Belgium's "Zeebrugge" and the German "Bunde"). They apply a state-space formulation of a time-varying dynamic model using a specific algorithm, the Kalman filter, on data from March 2000 to February 2005. In their study, the authors find strong convergence of prices between the NBP and Zeebrugge, and find that when the Interconnector (pipeline connecting the UK gas market with Continental Europe in Zeebrugge) is closed, prices diverge, only to converge again when the pipeline is operating again. Interestingly, they do not find evidence of any price convergence between Zeebrugge and Bunde, indicating that there was no integration in continental Europe at that time, and concluded that this confirmed that the European natural gas market was not functioning properly yet. These findings were confirmed in the "DG Competition report on Energy Sector Inquiry" initiated by the EC (2007), which concludes that a single gas market is not yet established as evidenced by large price differences across EU countries.

However, more recent co-integration analyses for North-Western (NW) Europe for the period 2007-2010 based on hub prices do demonstrate that the "Relative Law of One Price" holds between the six largest gas trading hubs in NW Europe (UK's NBP, Dutch TTF, Belgian Zeebrugge, German Gaspool and NCG, and the French PEG) (Harmsen, 2010, Harmsen and Jepma, 2011). This implies that the hubs form one large integrated region, where players are no longer bound to a specific location for selling and buying gas, and that arbitrage reduces price differences to the marginal cost of transport. Nevertheless, Harmsen (2010) does emphasise that there are no hubs that show perfect market integration, which might indicate the existence of barriers to trading in the European gas market, like potential cross-border transport capacity or information inefficiencies.

Finally, Siliverstovs et al. (2006) were the first to investigate the degree of market integration of international, cross-continent natural gas markets. They also used the co-integration framework to demonstrate a high level of integration within continents, but not yet between North America and Continental Europe (based on period 1990s – 2004). However, Neumann (2008) analysed the relationship between North America and UK two years later for the period 1999-2008 and concludes that prices, possibly due to a link established by LNG trade, do converge between the US Henry Hub and the British NBP, indicating some market integration across the Atlantic.

2.2.6 Literature Survey Conclusions

This literature survey demonstrates the limited amount of research performed to quantify the impact of gas market integration on society. Where studies have been initiated, the focus is on quantification of the impact of market liberalisation, where the most common factors investigated are price and security of supply. The fact that the literature is not conclusive on the impact of liberalisation on either price or security of supply, nor identifies true impact from market integration, only stresses the relevance of this study. In addition, it confirms our belief that for gas markets price and security of supply are the most important parameters to consider when assessing the impact of gas market integration. What can be concluded is the importance of sufficient physical connectivity between gas markets for commercial integration to occur, either by pipeline or by LNG.

2.2.7 Bibliography

Asche, F., Osmundsen, P. and Tveteras, R. (2001) "Market integration for natural gas in Europe", *International Journal of Global Energy Issues*, Vol. 16, pp. 300–12.

Asche, F., Osmundsen, P. and Tveteras, R. (2002) "European market integration for gas? Volume flexibility and political risk", *Energy Economics*, Vol. 24, pp. 249–65.

Brau, B., Doronzo,R., Fiorio, C.V., and Florio, M. (2010). "EU Industry Reforms and Consumers' Prices", *The Energy Journal*, Vol. 31, No. 4, pp.167-181.

Copenhagen Economics (2005). "Market Opening in Network Industries: Part I" Final Report, Brussels, European Commission.

Cuddington, J.T. and Wang, Z. (2006). "Assessing the degree of spot market integration for U.S. natural gas: evidence from daily price data". *Journal of Regulatory Economics*, Vol. 29, pp. 195-210.

Ernst & Young (2006). "Final Report - Department of Trade and Industry Research Project on the Case for Liberalisation", London.

European Commission Competition DG (2007). "DG Competition Report on Energy Sector Inquiry", Brussels.

European Commission (2011). "Communication from the commission to the European parliament, the council, the European Economic and Social Committee and the Committee of the Regions – Energy Roadmap 2050", Brussels (15/12/2011).

Harmsen, R. (2010). "On the Integration of the Natural Gas Market in the European Union", University of Groningen.

Harmsen, R., and Jepma, C. (2011). "North West European Gas Market: Integrated Already?" (www.europeanenergyreview.eu)

Heather, P. (2012). "Continental European Gas Hubs: Are They Fit For Purpose?" Oxford Energy.

Joskow, P.L. (2005). "Supply Security in Competitive Electricity and Natural Gas Markets", London.

King, M., and M. Cuc (1996). "Price Convergence in North American Natural Gas Spot Markets" *Energy Journal*, Vol. 17, No. 2, pp. 17-42.

Jeff D. Makholm (2007). "Seeking Competition and Supply Security in Natural Gas : The US Experience and European Challenge", Boston.

Neumann, A., Siliverstovs, B., and Von Hirschhausen, C. (2006). "Convergence of European Spot Market Prices for Natural Gas? A Real-time Analysis of Market Integration Using the Kalman Filter," *Applied Economics Letters* Vol. 13, No. 11, pp. 727–732.

Neumann, A. (2008). "Linking Natural Gas Markets - Is LNG Doing Its Job?", Berlin.

Noel, P. (2012). "Singapore, Helsinki or Brussels - Policy Approaches to Baltic Gas Security".

Noel, P. and Findlater, S. (2010). "Measuring Gas Supply Security – an Indicator for Russia dependent Europe".

Pollitt, M.G. (2012). "The role of policy in energy transitions: Lessons from the energy liberalisation era". *Energy Policy*, Vol. 50, pp.128-137.

Siliverstovs, B., L'Hegaret, G., Neumann, A. and Hirschhausen, C. V. (2006). "International market integration for natural gas? A cointegration analysis of prices in Europe, North America and Japan". *Energy Economics* Vol. 27, pp. 603–15.

Stern, J. and Rogers, H. (2011). "The Transition to Hub-Based Gas Pricing in Continental Europe". Oxford Energy.

Vany de, A. & Walls, W.D. (1993). "Pipeline access and market integration in the natural gas industry: evidence from cointegration tests". *Energy Journal*, Vol. 14, No. 4, pp. 1-19.

Walls, W. D. (1994). "Price convergence across natural gas fields and city markets". *The Energy Journal*, Vol. 15, pp. 37–48.

2.3 ELECTRICITY MARKETS

We can distinguish several stages to the reform of the electricity market. At present Europe is going through a phase of introducing market coupling as a mechanism for improving the international integration of the energy market. Before that, there was a phase of liberalising energy markets, which took effect mainly at a national level, albeit that some countries proceeded with international integration with neighbouring markets at their own initiative, such as the Nordpool. In the future, there might be further deeper integration.

The academic literature tends to see some form of locational marginal pricing (LMP), also described as nodal pricing, as representing full market integration of a market in electricity. Thus we can distinguish between a literature on LMP, being representative of full integration, and a literature on market coupling, representing the study of the practical implementation measures being introduced in Europe. There is also a literature on the liberalisation experience in Europe. One aspect of that liberalisation was the vertical unbundling of energy enterprises, and there is also a literature examining that aspect in particular and whether it has increased cost.

We now consider these areas of literature in the order mentioned in the previous paragraph. In general it can be said that the amount of literature that actually quantifies the benefits of either market liberalisation or market integration is rather small. Thus only a fairly limited study can be given.

2.3.1 Literature estimating the benefits of full market integration

Neuhoff et al (2011) presents a review of previous work on attempts to quantify the effects of full market integration in electricity markets, and makes clear that there is relatively little work in the area. Thus we will pay some detailed attention to the small number of serious studies that have been undertaken.

Neuhoff et al (2011) addresses a topic similar to one of the main parts of this study. It studies the effect of additional integration in the European electricity market (the model covers EU apart from UK, Ireland, Sweden and Finland) and the benefits it would have for improving the utilisation of additional wind capacity, in line with targets for increased quantities of renewable energy. Thus in terms of institutional scenarios, it is comparing deeper forms of market integration than presently exist in Europe, in particular nodal pricing, with the present methods of zonal pricing based on net transfer capacity (NTC) and total transfer capacity (TTC) methods, that are much used in Europe, or will shortly be. In terms of the wind capacity, the main scenario it studies is derived from the Tradewind study, having 125GW of installed capacity, providing up to 38GW of delivered output during a windy period.

Neuhoff et al (2011) finds the consequences of moving to the deeper form of integration are that:

- "…an increase of up to 34% in international MW transfers between countries, depending on wind power penetration. This means that the existing network capacity can adequately accommodate large volumes of intermittent energy sources…" ie, better market integration is a substitute for substantial quantities of additional transmission capacity
- "Annual savings of system variable (mainly fuel) costs … range from €0.8 - €2.0 billion depending on the penetration of wind power. This is represents an average of 1.1% - 3.6% of *[the]* operational costs…" of the electrical system.
- "Weighted marginal prices are lower under a nodal pricing regime in 60% to 75% of EU countries."

Another important observation is that under nodal pricing, zones of similar prices do not correspond to national boundaries, nor are the zone boundaries stable to different wind inputs. This paper highlights that it is precisely because historic electricity systems have been built with generation located relatively close to load, that it is when new generation is less well located for demand that the benefits of integration become more significant, more efficiently to use the transmission system and despatch the generation.

Neuhoff et al (2011) compare their results to another simulation study of better integration of wind capacity in the EU by Barth et al. (2009). Although it takes a quantity of 125GW of wind capacity like the Neuhoff study, they find only an estimated benefit from improved integration of 0.1% of system variable cost. Neuhoff et al (2011) attribute this much lower finding to a lack of detail in the Barth et al. model, which means it is not capable of identifying many of the important effects on the market and transmission system that Neuhoff et al (2011) found. Not identifying them, it cannot put much value on an institution for addressing them.

There is rather greater similarity between the magnitude of benefits that Neuhoff et al (2011) found and a number of studies of US markets. The PJM market is a market in the east of the USA, which applies nodal pricing. It recently expanded its area of operation to cover the some adjacent smaller areas, thus expanding nodal pricing to a total of about 51million people stretching from Washington DC to Chicago. Neuhoff et al (2011) summarised the research on this as follows, and applied their results to the larger EU market:

> "Mansur and White (2009) studied PJM and AEP/Dayton/ComEd operations before and after their merger. Their studies show that the volume of commercial transaction between the geographical regions increased by approximately 42% after the integration of both markets. The increase is consistent [with our] simulation results that showed up to a 34% increase in international flows. The incremental benefit of extending nodal pricing to the AEP/Dayton/ComEd areas to PJM was $180 million annually, which multiplied by the size ratios (50 GW for the three states, 820 GW EU) translates to a gain of $2.95 billion [for the EU]. As US fuel prices in 2009 measured in USD roughly correspond to EU fuel prices in Euro, the results can be interpreted as system savings of €2.95 billion [for the EU]. PJM estimates that the overall benefits of integrated operation of their system are $2.2 billion (approximately €1.8 billion) annually (Ott, 2010)."

The simple linear scaling up which Neuhoff et al (2011) suggests is perhaps over-simplified. US electricity transmission is more congested and less well connected than that of Europe, thus one might suppose benefits to proper integration of the market there are potentially a little larger than in Europe. On the other hand, the individual companies joined together in PJM were more uniform in characteristics, for example generation mix and operating methods, than European countries, thus offering potentially smaller benefits from trade than Europe. As Europe adds additional generation capacity in locations less well matched to the load, its transmission capacity will also become more congested, and thus the benefits of more effective use of the interconnection capacity will grow.

Mansur and White (2009) compare the actual before and after situation of an actual institutional change in the market that happened, as opposed to most of the studies which are simulation modelling approaches to estimate the effect of hypothetical changes in market institutions. The study is interesting for its approach to estimating the gains from trade from the price spread changes that occurred following integration. This involved an econometric estimation of the supply functions for each of the markets that were brought together. The simulation models which estimate welfare gains, such as Neuhoff et al (2011) above, and those we discuss below such as Leuthold et al (2005, facilitate straightforward estimation of welfare gains because they cost functions for generation as modelling assumptions, an approach not available to Mansur and White.

A number of studies of more limited ambition are noted, i.e. at more local level. Leuthold et al (2005) is a study of the effect of integrating 8GW of offshore wind (i.e., at the northern periphery (the maximum amount they found can be integrated without grid strengthening) into the German market, again studying the improved integration from nodal pricing. The 310-node model they use for the German market is a much more detailed model than has been used for the transnational studies. However by not covering the wider international situation, one would expect that much wider benefits of international integration are not assessed. They found a social welfare gain of the order of 1.6%-2.3% (of a social welfare function), of which 0.6%-1.3% was attributable to moving to nodal pricing in the absence of the additional wind, and a further 1% came when 8GW of offshore wind was installed. In other words, about half the gain came from moving to nodal pricing before the addition of the wind power, and a further half of the gain came from the improved ability to integrate a generation expansion. We estimate the monetary value of these social welfare improvements, from the social welfare values they present, to be very roughly of the order of €800m per year. This is broadly of the same order of magnitude as the estimates in Neuhoff et al, taking into account it is addressing only Germany.

Green (2007) makes a similar study of the UK market, using a 13 node model, and produces a result of similar quantum to Leuthold, being a 1.3% saving in generation costs. The relatively small size of the change can be related to studying a market which has relatively little congestion; larger benefits are likely to come from integration over wider areas where there is more congestion on the interconnections.

Weijde and Hobbs (2011) study a purely theoretical market of just 4 nodes, what we might call a "toy model", and find benefits to better market integration as high as 10% of costs in specific cases. This probably sets an upper bound to the likely improvements in actual markets.

As well as day to day savings, greater integration can potentially give large savings in relation to single brief but difficult incidents occurring in grid management. For example Neuhoff et al (2011) points out that the PJM region in the US largely avoided the effects of the August 2003 blackout that affected much of the north-east USA and parts of Canada because its integrated system was better able to respond to the incident and take action to limit the effects. Watson (2011) mentions a price spike that occurred in December 2009 in Texas, which is claimed would likely have been avoided if the locational pricing system that was implemented there the following year had already been in operation, with large savings, potentially over $100m just from that one incident.

2.3.2 *Literature estimating the benefits of market coupling*

The literature estimating the benefits of market coupling is even more limited. We find two researchers have attempted simulation models to assess the benefits of FBMC in the CWE region (France, Germany, Netherlands and Belgium), which have now been coupled for some time, (Germany joining later). We find one attempt to estimate the welfare benefits accruing to an implemented market coupling, albeit not precisely that of the Target Model. There are also some studies which note the effectiveness in practical terms of FBMC, (e.g. Glachant (2010)) and also show the price approximation that has occurred (eg Dijkgraaf and Janssen (2007), Moss (2009)), but without attempting to estimate the welfare benefit arising.

De Jong, Hakvoort and Sharma (2007) built a simulation model of the CWE region – France, Germany, Netherlands and Belgium – to estimate the welfare effects that flow-based market coupling (FBMC) would have on those countries. The model finds that the welfare benefits are mainly experienced in the Netherlands, which is a substantial net importer, and thus likely benefits most from the increased price approximation in the region. The aggregate welfare benefits are estimated of the order of €200m per year. The model also considers a scenario in which each border's transmission capacity is increased by 1,000MW, and also by 2,000MW. The welfare benefits of FBMC increase quite substantially, to about €500m per year in these scenarios, and Belgium starts to obtain gains when the capacity is sufficiently expanded. This tends to indicate that existing capacities are too low, and that additional capacities will be most effectively used with methods that better integrate markets.

The model is somewhat simplified from the actual implementation of FBMC in CWE. Although they have used more detailed transmission models to compute the characteristics of the individual national markets, for modelling FBMC they have just a 4-node model, one node per country. In practice, for the implementation of FBMC, Germany has been divided into several zones. So it is possible that the model does not have the level of richness that is represented in the present day implementation of FBMC for CWE, and thus may under-estimate the actual impact of FBMC.

We noted above that whilst nodal pricing tends to be seen as "full" integration of markets, market coupling is seen as being an implementation of market integration that falls slightly short of it. Oggioni and Smeers (2010a) build a toy model, using a particular 6-node network commonly used for illustrative purposes by a variety of researchers, indicating that market coupling tends to have welfare losses relative to a nodal pricing implementation, these welfare losses varying according to details of the coupling implementation and the behaviours of the market participants.

Oggioni and Smeers (2010b) also adapt this model to make a simulation model of the CWE region rather similar to that of De Jong, Hakvoort and Sharma (2007) above, using the same

4-node network. They do not attempt to model the practices in this market before FBMC, rather they compare FBMC with nodal pricing as a base case. They find that in the ideal case, with (unlikely) ideal behaviour by all market participants, market coupling has only €4m annual welfare reduction relative to nodal pricing. But it should be understood that this is nodal pricing in the 4-node model, one price per country, not a full nodal pricing implementation in the sense of the more detailed LMP models of Leuthold et al, Neuhoff et al, etc., discussed in the previous section. Thus it does not measure the loss of benefit of moving to a purer nodal pricing model, rather only it compares different solutions in the 4-node case. They model increasingly less good behaviour by the market participants and find that they can increase the welfare loss to €4,000m in the worst case. This tends to indicate that behaviour by the market participants is significant, and actual observation of the markets is necessary to understand the true case. Although applied to CWE data, it is a somewhat academic study of limited practical relevance. They do, however, note that flows to Belgium by both interconnectors are the most congested, indicating that Belgium would particularly benefit from increased interconnection capacity.

Both these simulation studies of the CWE region are based upon generation and transmission data from around 2005. Thus they do not reflect the more recent large growth in renewable generation, and thus do not have the richness or fact base to identify the important effects that Neuhoff et al (2011) and Leuthold et al (2005) found. Before recent developments in generation, both Germany and France tended to have rather adequate internal generation resources and internal transmission capacities to transmit them, with Belgium and Netherlands benefiting more from imports, though with acute capacity constraints in the case of Belgium. Thus modelling these scenarios it is perhaps unsurprising that neither France nor Germany exhibit notable welfare benefits from the FBMC: they may export more, but increased prices in their own market tend to offset the commercial gain of that in a net welfare calculation. These conclusions are likely to change when modelling scenarios with much larger quantities of renewables and closures of older stations, and more of the participants then have more to gain from trade.

Meeus (2011) studies how in principle one might assess the welfare changes resulting from the implementation of a new regime on an interconnector, having regard to the distribution of prices and usages of the cable. Because the public data does not provide everything needed for the calculation, he could not compute exactly the welfare change. However data on price and actual transfers relative to capacity available implies an upper and lower bound on the welfare change. Motivated by that, Meeus designs a "performance indicator", which Glachant (2010) interprets as being an approximation to the welfare performance of the implementation. This performance indicator is computed as "unused capacity times the price spread", which Meeus reports in €/hr. If there are no flows against the price differential, then the performance indicator will be zero. This is suitable only for measuring the efficiency on one particular interconnector, not the wider market as a whole. But it is operable as a method for assessing the efficiency of FBMC on any given interconnector.

Meeus then uses this method to study the history of the Kontek cable from East Denmark to Germany, first from the period of no coupling, through two implementations of approximate coupling. This is a separate arrangement from the similar approximate coupling on the West Denmark to Germany interconnector (see Kristiansen (2007a) and Kristiansen (2007b)). The first approximate coupling arrangement was called Volume Coupling, and was soon abandoned, as it appeared to be mistaken in its institutional design. It increased the level of flow against the price spread, and, annualising Meeus's indicator according to Glachant, the welfare shortfall on the Kontek cable was of the order of €18m per year. This has now been replaced by so-called one-way market coupling. This is not a perfect market coupling, as there is still some flow against price differential, but the level is reduced to about 5% of the original market design. The estimated welfare gain is about €10m per year on that one cable.

In summary, simulation studies of FBMC find efficiency benefits, but to the extent that these are fairly modest, it may well be because the models do not have sufficient richness to identify all of the transmission difficulties that FBMC may relieve, and because they are based on earlier generation portfolios which place less stress on the installed transmission systems. They indicate substantial value to increasing the transmission capacity, and that FBMC will then be of even greater value in efficiently managing that capacity. A before-and-after study of the Kontek finds some fairly modest welfare benefit of FBMC on that cable.

2.3.3 *Literature estimating the benefits of market liberalisation*

Pollitt (2009a, 2009b, 2012) comprise a number of survey articles on the consequences of liberalisation in electricity markets. He draws on earlier survey articles he wrote, Pollitt (2009a, 2009b). Pollitt (2009a, 2009b) both note that whilst there are indications that electricity market reform in Europe have delivered welfare benefits and cost reductions, there is less evidence of benefits in terms of prices to consumers. We discuss the main evidence for this following. Pollitt (2009a) also concludes that benefits are greater when the liberalisation program is well designed.

Broad evidence of the value of the liberalisation programme comes from Copenhagen Economics (2005) which studies the impact of reforms in network industries from 1990-2001. This study was based upon constructing indices of the level of reform, in order to extract from a data on broad economies the effect of differing levels of liberalisation, in the context of a general equilibrium model to estimate the overall macroeconomic impact. This showed that the benefit from liberalisation was around 2% of GDP, of which two thirds arose from electricity and telecoms reforms (p.22). The variation in benefits between countries is substantial: 'Those member states which opened markets more and which started early have gained the most.' But a degree of discomfort as to the robustness of the conclusions must arise from this kind of study, where seemingly arbitrary indices of liberalisation are used as an explanatory variable, although the outcome encapsulated in the sentence just quoted tends to reinforce that broadly sensible results were found from this approach.

The Copenhagen Economics (2005) study also looked in more detail at the electricity sector specifically, and this found rather weak evidence of the benefits from liberalisation, in contrast to the macroeconomic model. This is probably because they were mainly studying prices, rather than costs or efficiency, and as we note below, this may be because the benefits of cost and efficiency may be substantially attached by other stakeholders than customers. Also, fuel prices fell over their data period, because of movements in international markets, and they have not properly attempted to separate the effect of that on electricity prices from institutional change. One detail they identified which appears robust is that unbundling generation from transmission had the largest effect in reducing prices.

Evidence of the weakness of the effect of liberalisation on consumer prices (as opposed to efficiency) comes from Fiorio, Florio and Doronzo (2007). They use three indices of market reform, again of a somewhat arbitrary form, to assess, separately, the effect of ownership, entry, and vertical integration on household electricity prices in EU-15 over 1978 to 2005. They find none of the indices has a significant effect. But although not statistically significant to the desirable level, the signs are interesting – allowing entry and reducing vertical integration reduce prices, but the sign on the ownership variable tends to suggest that public ownership reduces prices. Hattori and Tsutsui (2004) have a similar model, looking at effects on electricity prices in OECD countries, and find similar mixed effects on prices. The likely explanation here is that governments reduce subsidies and cross-subsidies during episodes of reform, with some partial cover from the cost reduction. Thus the benefits of cost reductions from reform can be spread among various stakeholders, as following studies also indicate. Evidence on prices is also affected by the fact that changes in fuel prices can change electricity prices.

More detailed evidence of the benefits of liberalisation comes from a number of single country studies. Pollitt (2012) collects together in the following table the results of a number of studies which have quantified the welfare effect of electricity liberalisation in individual countries, including developing countries. Some of the developing country cases report very large changes, presumably because the power sector difficulties had become a constraint upon economic development, and liberalisation was a route to resolving that constraint. The other cases show more modest benefits in the range of 2% to 9% of enterprise turnover. It is apparent that not all of these gains go to consumers, since government may take the opportunity to unwind subsidies or cross-subsidies.

Authors	*Reform and company/date/country studied*	*Measured NPV of reform (central estimate)*	*Key distributional impacts identified*
Galal et al. (1994)	Privatisation of CHILGENER—generation and transmission/1981–1986/Chile	Permanent gain in welfare of 2.1% of 1986 sales	2/3 of aggregate gains go to foreign share holders
Galal et al. (1994)	Privatisation of ENERSIS—distribution/1986/Chile	Permanent gain in welfare of 5% of 1986 sales	Paying consumers gain an amount almost equal to the aggregate impact
Newbery and Pollitt (1997)	Privatisation and breakup of CEGB—generation and transmission monopoly/1990/UK	Permanent gain of 6% of 1995 turnover	Consumers lose initially and overall, CO_2 and SO_2 benefits significant
Domah and Pollitt (2001)	Privatisation of 12 Regional Electricity Distribution Companies/1990/UK	Permanent gain of 9% of 1995 turnover	Consumers lose initially
Toba (2002)	Privatisation of distribution company—Meralco/1986/Philippines	Permanent gain of 6.5% of 1999 sales	Most of net gain is reduction in CO_2 and NOX, consumers do gain by more than 50% of aggregate gain
Mota (2003)	Privatisation of distribution companies/1995–2000/Brazil	One off gain equal to 2.5% of GDP	Producers gain around 2/3 of aggregate benefit
Toba (2007)	Introduction of Power Purchase Agreements with Independent Power Producers by incumbent generator, NPC/1990–93/Philippines	One off gain of around 13% of GDP	Economy wide benefit due to earlier ending of power crisis
Anaya (2010)	Privatisation of 2 distribution and retailing companies/1994/Peru	Permanent gain of 27% of costs when earlier connection included	Existing consumers lose, new consumers gain earlier connection

[a] Florio (2004) finds overall welfare gains from the whole of the UK utility privatisation programme in terms of expenditure trends. For electricity he suggests consumers gain by around £1.4bn, with real prices down by 17%. Using data envelopment analysis techniques, Arocena et al. (2011) find that the restructuring of the Spanish electricity sector in 1998 was associated with significant performance improvements (in terms of increased economic value and productivity growth) before and after restructuring. After restructuring, consumers received substantial gains via lower prices and the companies gained (even more than consumers) via increased profits.

Table of Social cost benefit analyses of restructuring and privatisation taken from Pollitt (2012)

Pollitt also draws attention to studies of the US markets, and reports that:

> "Fabrizio et al. (2007) use time series econometrics of US power plants to show that reform is associated with up to 5% reduction in plant level non-fuel generation costs. Similarly, Stratford (2006) found cost savings at coal fired power plants of 2–3% following the opening of transmission systems to wholesale power market competition in 1996, in regions with independent system operators. Joskow (2006b) used time series econometrics to find that competitive wholesale and retail markets reduced prices (relative to their absence) by 5–10% for residential customers and 5%

for industrial customers. Barmack et al. (2007) look at the wholesale power market in New England and find a net gain of 2% of costs."

In the following section we consider in more detail estimates the literature on cost savings experienced in the liberalisation of the UK electricity supply market, and compare it with the Europe-wide estimates reported by Copenhagen Economics (2005) above.

2.3.4 *Comparison of liberalisation benefits of UK and Europe*

Case Study E1: Liberalisation of the Electricity Market in the UK

The liberalisation of the electricity market in England and Wales took place in two main stages:

- **Restructuring Production**: The CEGB[1] was an integrated transmission and generation company, controlling all generation and high voltage transmission in England and Wales. Distribution and retail was provided by several regional supply companies. The CEGB was broken up into four pieces, a transmission operator, two conventional generating companies, and a nuclear generating company. New entry into generation was permitted, facilitated by gas supplies coming on-stream. A power exchange was put into place.
- **Competition in Supply**: Distribution was unbundled from energy supply, allowing competition among existing market participants and new entrants to supply retail customers with energy. Energy suppliers typically provide the retail customer with a complete service, procuring distribution services from the distribution monopoly at regulated prices, likewise transmission services, and making their own arrangements for energy.

Each of these separate stages of liberalisation produced measurable effects on the market.

- The first stage of liberalisation, represented by the break-up of CEGB, is estimated to have led to a permanent 6% fall in generation and transmission costs, which in 1995-6 were about £6 billion. This is worth £9.6 billion discounting at 6%. Source: Newbery and Pollitt (1997)
- The second stage of liberalisation, retail competition, was estimated to be worth £6.1 billion discounting at 6% in a central scenario compared to revenue in 2004-5 of £3 billion (all figures at 1995 prices). Domah and Pollitt (2001)

Somewhat different arrangements applied in Scotland, where the two regional vertically integrated companies were left intact. Studies have not identified the same levels of consumer benefits there.

We now make a number of simple calculations to compare these estimates reported in Case Study E1 to those provided for the EU by Copenhagen Economics (2005), mentioned above. From the preceding, total costs for the ESI in England and Wales might therefore be about £9 billion. The UK's ESI contribution to GDP in 1996 was £11.4 bn and the share of England and Wales generation in major generators to that of the UK as a whole is 85% (in 2008, when the share of consumption was 87.5%)[2] so that the estimated GDP of the England and Wales ESI is £9.7 bn, which is close to the estimated cost.

The total contribution of all energy sectors to the UK economy has varied between 5.2% and 3.5% between 1990 and 2008, and was 5.1% in 2008.[3] The reasons for the variation are that oil and gas production have tended to decline, but prices have risen. Employment has fallen steadily from 345,000 to 158,000 over this period, or by more than half, so productivity has clearly risen on a simple measure. In 2008, oil and gas amounted to 3.5% of GDP, and the ESI accounted for 1.3%. Over the longer period, the ESI share of GDP has varied between 0.9% and 2%.

Taking an average (1980-2009) value of the ESI share of GDP of 1.4% and assuming that this was fairly typical for EU member states, we can then calculate the impact of liberalising the ESI on GDP, taking the most favourable of the UK cases, namely the most liberalising restructuring which took place in England and Wales.[4]

Thus we calculate the total cost reduction for the ESI in England and Wales is £942m on an average total cost of about £9 billion, or a 10% cost reduction (or 8% of the ESI GDP), based upon a 6% of the £6.1 billion costs of supply and distribution plus 6% of the generation and transmission cost at £6bn. The reason for the non-additivity is that one is supplying the other and the second liberalisation induced a further reduction in the costs of generation which was experienced through the supply and distribution business. Thus liberalisation might be worth 10% of 1.4% of GDP in reduced costs, or 0.14%. Even if the ESI in Europe contributes 1.9% to GDP (Copenhagen Economics, 2005, Table 5.1, p61), the estimated cost reduction would be just under 0.2% of GDP, which is surprisingly large.

Copenhagen Economics (2005, table 4.3) found an average productivity gain for the EU15 of 2.3% between 1990 and2001, and a long-run gain of 7-8%, which is rather less than the estimate of 8-10% for England and Wales, and so not implausible. It also singled out unbundling transmission as a key driver, although it noted that "The key is that MOM2 (i.e. unbundling transmission) enters F1. However, so do many other Market Opening Milestones making it virtually impossible to identify MOM2 as the single most important policy to implement when aiming at lower prices and higher productivity." (p59)

Copenhagen Economics (2005, table 5.5) estimated that the effect of market opening of all utilities from 1990-2001 might add 2% to value added and 1.9% to welfare. But the ESI is only one third of the size of all utilities, and its share in long-run productivity gains are only 5% of overall network industry productivity gain (with telecoms accounting for 53%). So its contribution to increased EU value added might be only 0.1% over this period, which is shorter than the period considered for liberalising the England and Wales ESI. Their estimate (at table 5.11) for the lower bound of the long-run effect of market opening of all utilities would be to add 4.1% to value added and 3.7% to welfare, but the ESI's share in long-run productivity gains are only 8.3% of overall network industry productivity gain (with telecoms accounting for 63%) so its contribution to increased EU value added might be 0.34% in the long run (lower bound; the upper bound might be as high as 1%).

[2] *https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65841/7345-elec-gen-2008-2011-et-article.pdf*

[3] *UK Department of Energy and Climate Change, UK energy sector indicators 2009*

[4] *The Scottish and Northern Irish ESIs were less liberalised in that they retained much of their vertical integration.*

So, one might conclude that liberalising the ESI would add something between 0.1 and 1% to value added, with a more realistic (micro-founded) estimate for the long-run effects in the range 0.2% to 0.4%.

2.3.5 *Costs and benefits of unbundling*

Meyer (2012) presents a rather different theme, in carrying out a survey of work on the economies of scope and scale in electricity, which purports to show that unbundling of generation and distribution tends to increase operating costs. Quite startling losses of synergy in the range of 10%-29% of operating costs are reported there. Pollitt and Steer (2011) indicates why this type of work should not be taken seriously as an estimate of actual cost increases incurred upon unbundling. The papers studied by Meyer are all studies of cost functions of companies, assessed econometrically, an area of work which is problematic. The loss of synergies reported arise from the estimated cost functions, and are not demonstrated cost increases consequent upon unbundlings that have actually occurred. Indeed the evidence of true before-and-after studies cited above tends to show cost reductions from market liberalisation characterised by unbundlings, especially unbundlings of generation from transmission and distribution, which Meyer would indicate was the most costly unbundling, i.e. quite the reverse of Meyer's theoretical prediction.

This is not to say that there are no cost increases from unbundling - Kwoka and Pollitt (2010) show that unbundling does appear to raise electricity distribution costs, relative to firms which do not unbundle, studying markets in the US. But the point is that these are costs that are more than offset by the competitive and dynamic advantages of an unbundled and competitive market, as found by Triebs, Kwoka and Pollitt (2010). The EC Energy Enquiry came to a similar conclusion, that vertical integration in electricity presented a wide range of barriers to competition, entry, price formation and thus unbundling at this level was the prerequisite to market liberalisation. Better market integration is likely to assist in recreating the synergies that might previously have come from vertical integration, while retaining the benefits of competition.

2.3.6 *Literature Survey Conclusions*

In summary, we found that benefits from improved integration lie broadly in the range of 1% to 10% of system costs, most frequently in the lower part of that range. In the context of adding a substantial quantity of additional renewables, consistent with the requirements over the next decade or so, market integration allows a substantially greater quantity to be added without grid reinforcement, and this benefit can be about half the benefit of the improved market integration.

There are few quantitative studies of Flow-Based Market Coupling, and certainly none of a broad scale, and the simulation studies are probably in insufficiently rich models to find all benefits. The scale of welfare benefits found is clearly of a smaller scale than the full integration models, which have been studied in more detail.

Market liberalisation has been found to reduce costs in the range of 2% to 10%. The proper design of the liberalisation, and thorough implementation of it makes a difference to the level of the effect, and proper unbundling between generation and grid is a key level of liberalisation. In terms of the macro-economic effect, this most likely lies in the area of 0.2% to 0.4%.

2.3.7 *Bibliography*

Barth, R., Apfelbeck, J., Vogel, P., Meibom, P. & Weber, C. (2009): "Load-flow based market coupling with large-scale wind power in Europe", In: Proceedings of the 8th International Workshop on Large Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms. 14-15 October 2009, Energynautics Bremen 2009.

De Jong, H, Hakvoort, R and Sharma, M (2007): Effects of Flow-based Market Coupling for the CWE region, pp. 1-9, Proceedings of the 4th European Congress Economics and Management of Energy in Industry (ECEMEI2007) Nov. 27th-30th (2007).

Dijkgraaf, E and Janssen, M (2007), Price convergence in the European electricity market, Erasmus Competition and Regulation institute, Working Paper, (2007)

Domah, P.D. and Pollitt, M.G., (2001): The restructuring and privatisation of the regional electricity companies in England and Wales: a social cost benefit analysis. *Fiscal Studies* 22 (1), 107–146.

Fabrizio, K., Rose, N., Wolfram, C., (2007): Do markets reduce costs? assessing the impact of regulatory restructuring on U.S. electric generation efficiency. American Economic Review 97 (4), 1250–1277.

Fiorio, C.V., Florio, M. and Doronzo, R. (2007): The Electricity Industry Reform Paradigm in the European Union: Testing the Impact on Consumers, Paper delivered at Consumers and Utility, Reforms in the European Union Conference, Milan, June 8-9, 2007.

Glachant, J-M (2010): The Achievement of the EU Electricity Market through Market Coupling, EUI Working Paper RSCAS 2010/87, Robert Schuman Centre for Advanced Studies, Florence Institute of Regulation

Green, R. (2007): "Nodal Pricing of Electricity: How Much Does it Cost to Get it Wrong?", Journal of Regulatory Economics 31 (2): 125-149.

Hattori, T., Tsutsui, M., (2004): Economic impact of regulatory reforms in the electricity supply industry: a panel data analysis for OECD countries. Energy Policy 32 (6), 823–832.

Joskow, P., (2006). Markets for power in the United States: an interim assessment. The Energy Journal 27 (1), 1–36.

Kristiansen, T (2007a): A preliminary assessment of the market coupling arrangement on the Kontek cable, Energy Policy 35 (2007) pp3247–3255.

Kristiansen, T (2007b): An assessment of the Danish–German cross-border auctions, Energy Policy 35 (2007) 3369–3382

Kwoka, J., Pollitt, M., 2010. Do mergers improve efficiency? Evidence from restructuring the US electric power sector. International Journal of Industrial Organization 28 (6), 645–656

Leuthold, F., Rumiantseva, I., Weigt, H., Jeske, T. & Hirschhausen, C. von (2005): "Nodal Pricing in the German Electricity Sector – A Welfare Economics Analysis, with Particular Reference to Implementing Offshore Wind Capacities", Working Paper WP-EM-08a, Dresden University of Technology, Chair for Energy Economics and Public Sector Management.

Mansur, E. T. & White, M. W. (2009): Market organization and efficiency in electricity markets, (2012 revised version)

Meeus, L., (2011): Implicit auctioning on the Kontek Cable: third time lucky? Energy Economics, 33(3), pp. 413-418

Meyer, R (2012): Vertical Economies and the Costs of Separating Electricity Supply—A Review of Theoretical and Empirical Literature, The Energy Journal (IAEA) 34(4) pp 161-184.

Moss, Ian (2009): APX-ENDEX Market Coupling & BritNed, Presentation at the BritNed Connect Seminar, London, 8th December 2009

Neuhoff, K., R. Boyd, T. Grau, J. Barquin, F. Echabarren, J. Bialek, C. Dent, C. von Hirschhausen, B. F. Hobbs, F. Kunz, H. Weigt, C. Nabe, G. Papaefthymiou and C. Weber (2011), Renewable Electric Energy Integration: Quantifying the Value of Design of Markets for International Transmission Capacity, DIW Berlin Discussion Papers 1166.

Newbery, D.M. and M.G. Pollitt (1997): The Restructuring and Privatisation of the CEGB-Was it worth it?, *Journal of Industrial Economics*, XLV (3), 269-303

Oggioni, G and Smeers, Y (2010a): Market Coupling and the Organization of Counter-Trading: Separating Energy and Transmission, ECORE Discussion Paper, 2010/99

Oggioni, G and Smeers, Y (2010b): Degree of Coordination in Market Coupling and Counter-trading, EUI Working Paper RSCAS 2010/24, Robert Schuman Centre for Advanced Studies, Loyola de Palacio Programme on Energy Policy

Ott, A. (2010): "PJM - LMP Market Overview", Presented at CPI/Re-shaping workshop in Brussels.

Pollitt, M., (2009a): Evaluating the evidence on electricity reform: lessons for the South East Europe (SEE) market. Utilities Policy 17 (1), 13–23.

Pollitt, M.G., (2009b): Electricity liberalisation in the European Union: a progress report, Electricity Policy Research Group Working Paper No. 0929.

Pollitt, M. and Steer, S (2011): Economies of Scale and Scope in Network Industries: Lessons for the UK water and sewerage sectors, EPRG Working Paper 1124

Pollitt, M. (2012): "The role of policy in energy transitions: Lessons from the energy liberalisation era", Energy Policy 50, pp128-137.

Stratford, D., 2006. Measuring gains from regional dispatch: coal-fired power plant utilisation and market reforms. The Energy Journal 27 (1), 119–138.

Triebs, T., Kwoka, J., Pollitt, M., 2010. The Direct Costs and Benefits of US Electric Utility Divestitures, Electricity Policy Research Group Working Paper No.1024.

Van der Weijde, A. D. Hobbs, B.F. (2011): "Locational-based Coupling of Electricity Markets: Benefits from Coordinating Unit Commitment and Balancing Markets", Journal of Regulatory Economics 39 (3), pp 223-251

3. MODELLING METHODOLOGY

3.1 INTRODUCTION

This chapter sets out defining key parameters for the modelling, including in particular indicators by which benefits will be measured, and scenarios which will be modelled. We divide the consideration of scenarios into

- Policy scenarios: the stylised descriptions of the states of the world which describe the different policy/legislation situations that will be compared. These are the different states of the world which the report should produce comparisons of.

- Market scenarios: the descriptions of economic factors within which those policy scenarios take context. These are based upon the defined PRIMES scenarios used by the EC for energy policy.

Below we discuss the indicators, policy scenarios and market scenarios, taking gas and electricity in turn.

3.2 INDICATORS

3.2.1 Gas

We investigate two main indicators for understanding the benefits of market integration: wholesale price level development, and security of supply. The relevance of these two indicators is confirmed in the literature review conducted as part of this study.

We investigate the development of the "border prices" of the EU27 countries (or regions of several countries with similar price formation) in different scenarios, where we take "border prices" as a proxy for wholesale price levels. Border prices are the average prices at which gas is imported into a given country from different supply sources. These prices are reported by Eurostat. We consider changes in border prices as an indicator of economic benefit and are thus not concerned with the actual absolute wholesale price levels in each individual country. We work from an underlying general assumption that European gas markets will remain in a situation of oversupply for the foreseeable future, in which the different (emerging) European gas hubs maintain their current liquidity, or further increase their liquidity. As world-wide supply (and demand) developments can shift rapidly, this underlying general assumption should not be understood as our prediction of the supply/demand balance in Europe, but rather as a possible scenario for development of European gas markets. Under this assumption of continued oversupply in Europe, hub price signals will continue to gain relevance in border price setting, and the prevalence of other price setting mechanisms will gradually recede. Over time, prices at the different hubs across Europe will converge, mirroring the situation now prevalent already in NW-Europe. The speed at which these changes take place is dependent on the development of the supply/demand balance in world-wide and European gas markets, as well as the development of regulation and market design across EU27. We do not make any predictions as to the time necessary to reach this state of converged hubs across Europe.

Currently hub prices across Europe are lower than prices in import contracts that still contain a link to oil product prices, and therefore increasing importance of hub prices leads to a reduction in border prices and thus an economic benefit to a given importing country.

Prices at gas hubs come about through the dynamics of supply and demand. In periods of tightness in the market, hub prices may increase to levels closer to (or indeed above) price levels that typical long term import contracts would have generated, and the full benefit as calculated in the method described above may not materialize. As it is not possible to predict Europe's long term supply/demand balance with any level of accuracy, the reference point we use is the situation in 2012, in which 'long' market conditions have resulted in a price differential between NW-European hub prices and oil-indexed import prices.

It should be noted that gas market integration in and of itself is not the underlying cause of the economic benefit calculated in this manner. Rather, market integration should be considered as a facilitator for this benefit to arise.

For security of supply, we consider the availability of sufficient production, import pipe, storage and LNG regasification capacity to fulfil demand in Europe, in the context of "N-1" security of supply in situations of peak demand. Benefits of integration are expressed as a reduction of the daily "GDP at risk" of a major supply disruption in each EU27 member state. Increased security of supply reduces the probability of occurrence of a supply disruption, but it is impossible to estimate the absolute reduction in probability of occurrence. Therefore we provide a probabilistic estimate: the reduction of GDP at risk of a reduction of 1% in the probability that a EU27 member state suffers a total gas supply interruption of one day in duration. The costs associated with increasing security of supply are estimated by calculating the additions in infrastructure that would be necessary to provide "N-1" security of supply to all EU27 countries.

A third aim commonly connected to European energy policy is environmental sustainability. For natural gas in the context of this study we have not investigated the impact of gas market integration on sustainability. Rather, the impact of integration in gas markets on sustainability is expected to become visible in power generation. As we assume that wholesale price levels of gas change depending on the level integration of markets across Europe, gas' competitiveness as a fuel in power generation changes, and therefore the volumes that are likely to be consumed. This will impact CO_2 generation depending on which other fuel is displaced.

3.2.2 Electricity

As the literature survey has made clear, it is dangerous to use price alone as a measure of welfare advantage in electricity markets, because the benefits from cost reduction can be divided among different stakeholders, including government through tax and subsidy changes, and the grid operator through changes in grid charges. Thus the key indicator of change in welfare for electricity will be cost. Nevertheless, during a period in which other factors are not changing to move the rent distribution, changes in prices might be relevant indicators of changes in efficiency, and this might become relevant in the case of some modelling outside the main model.

Our main model will address security of supply issues, and energy quantity by type of generator will facilitate CO_2 calculation using standard parameters. Since gas is a major fuel for electricity generation, there needs to be coordination with the gas modelling to avoid double-counting CO_2 from gas.

Our main model will consider only the future-looking modelling for electricity scenarios. For backward-looking assessments, and assessment of the current market-coupling approach, we employ a rather different modelling approach which we explore in Section 4 of this report.

3.3 Policy Scenarios

3.3.1 Gas

We define and analyse three "Policy" scenarios against the "Base case". The Base Case is the state of European gas market and their level of integration in 2012 (see Figure 3.1):

- Scenario 1 "2012 No Integration": A hypothetical "State of Europe today" in which no deliberate policies and efforts have been implemented to foster market integration across EU member states, either driven by the EU or by private parties. Potentially national market reforms have been implemented. Conceptually, the state of European gas markets of the late 1990's is rolled forward to 2012 market realities.

- Scenario 2 "Mid-State":– European gas markets are in transition towards integration. Full implementation of the "Third Package" across member states has taken place, and all other known measures and initiatives, public or private have been implemented. There are regions in Europe in which market integration has reached near completion, but full market integration across the EU27 has not yet been achieved.

- Scenario 3 "Full Integration": A hypothetical future state of Europe where full market integration has occurred and Europe operates as a single natural gas market with one hub-based price signal prevalent across Europe.

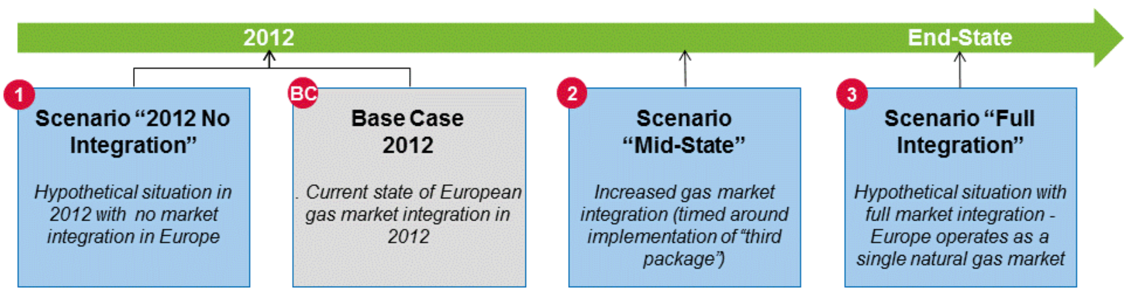


Figure 3.1: Policy Scenarios

Our starting point for the Base Case is that wholesale gas markets in different countries are in different situations in terms of liquidity, level of competitive intensity, price formation of border gas, regulation of end-user prices, and integration with neighbouring countries (both physical and traded markets). For practical purposes, we define a limited number of clusters with comparable countries. Each "Policy" scenario has a different impact on these different country clusters.

Note that this study deals with understanding and quantifying benefits of market integration, and not with the way in which market integration is or should be brought about.

3.3.2 *Electricity*

In the case of electricity, we take quite a different approach to the period up to 2015 and the period beyond 2015. In the 2004-2015 period, we take a data-driven approach observing what has actually happened, and projecting that forward the short distance to 2015. And for the period beyond 2015 we use a scenario modelling approach, assuming some version of full market integration will be achieved.

During the period 2004-2015, the main change that has occurred in the integration of electricity markets has been the introduction of market coupling. We attempt to estimate directly the economic effect market coupling has had in the case of some markets where there is available data. We then use some market size arguments to scale this up to the markets where market coupling is now used, and to those it should be introduced to by 2015.

Beyond 2015, we use a scenario modelling approach to assess the benefits of fully integrating EU electricity markets. The key objectives of our activity will be to examine the importance and quantify the benefits of integrating EU electricity market in facilitating a proper cross-border market in energy, but also in sharing the provision of system management services, such as frequency regulation, reserve and security.

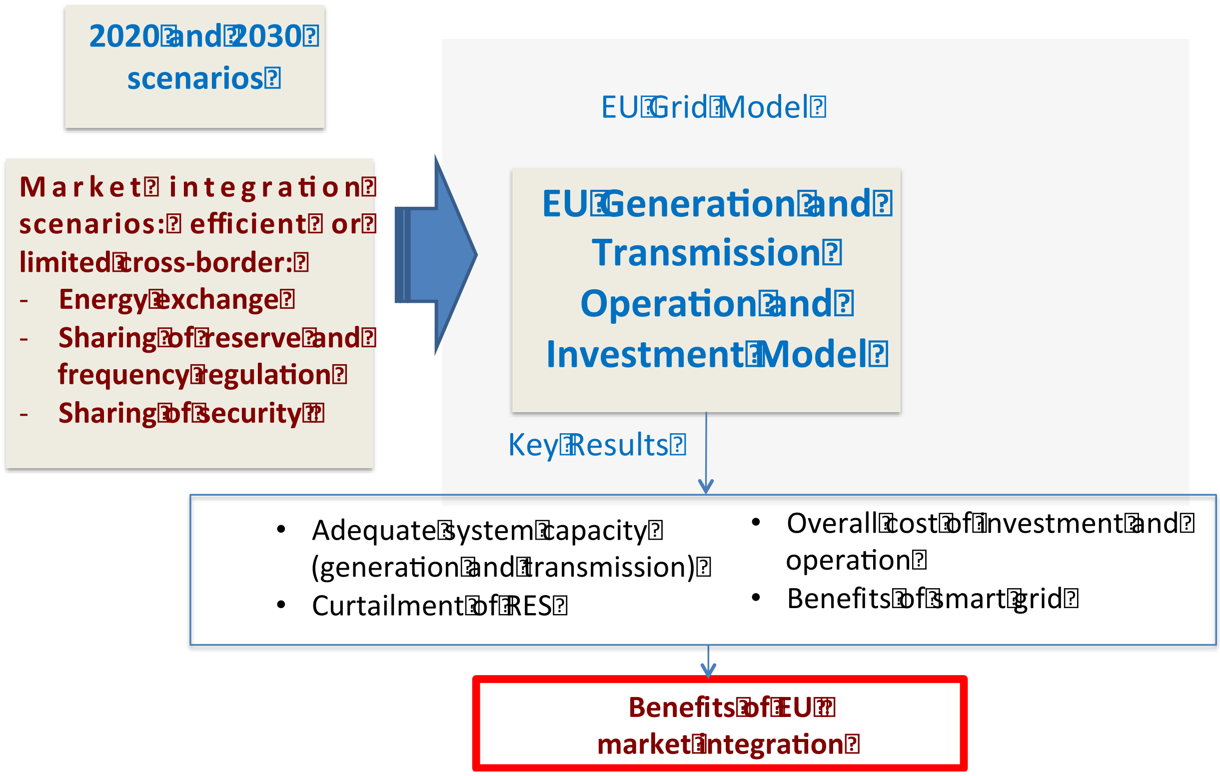


Figure 3.2 Approach to quantify costs and benefits of integrating EU Electricity Market in 2015-2030

As presented in Figure 3. 3.2, the approach taken in this project starts from adopting existing suitable market scenarios for 2015-2030 on which costs and benefits of integrating EU

Electricity Market will be quantified. Our approach to assessing the benefits of integration is first to create a policy scenario in which EU Electricity Market is fully integrated, in a basic sense. Then, we analyse the inefficiencies (welfare losses) in market operation and investment associated with reduced levels of integration, and also the benefits from further adjunctive integration measures such as may come from smart grids.

Since the PRIMES scenarios do not provide sufficient capacity to deliver security of supply – sometimes called adequacy of supply – to the standards each country generally requires,[5] we need to add in the costs of providing sufficient additional capacity. One costing of this is that it should be peaking plant. However in practice this plant appears to need to run more often than peaking plant, so an alternative costing is baseload gas plant. These two costings provide a range for the cost of the additional capacity needed to deliver the required security of supply in each scenario.

The key scenario to develop will be the one that best represents the likely level of integration resulting from the continuation of present integration policies. The baseline scenario defining the persistence of 2014 institutions is what we term the "energy neutral baseline". The 2014 electricity trading institutions mainly support short term arbitrage opportunities in the generation market. Most national electricity markets are broadly self-sufficient in their total energy requirements from generation, with cross-border trade being mainly opportunistic arbitrage in the short run. There are some exceptions, such as some modest persistent trade imbalances on several borders, and the relatively larger net electricity imports of a few countries. But in general, given the low cross-border transmission capacity existing in comparison to overall national demand levels, national self-sufficiency, or what might be termed energy neutrality, in electrical generation requirements, with only short term arbitrage, is a broad characterisation of the present situation in Europe.

Moreover we expect that this approximate energy neutrality in generation requirements is likely to persist, as the 2014 electricity trading system does not create a level of integration and market forces in trading to facilitate a move away from it. It is not reasonably feasible to make substantial new long term arrangements across boundaries for energy supply under the present trading arrangements. National governments explicitly speak of seeing the necessity to retain national self-sufficiency in electricity generation requirements. Governments clearly do not see it likely that economic agents in a country would be able to provide for their requirements by contracting for imports, but rather seek to plan to ensure that they can deliver national requirements for security at the peak.

The reason that the 2014 trading system will fail to provide for the level of trade in an integrated market is because in a truly integrated market the total quantity of trades across a given link will be a large multiple of the capacity of that link, even though the net flow, netting out flows in one direction from flows in the other direction, respects the capacity constraint of the link. This high level of trade and netting is what is observed, both in relation to longer term trades and shorter term trades, in much more fully integrated electricity markets, such as internal national markets, or the PJM market in the USA – see case study E2 following. In contrast, the cross-border arrangements in place in Europe currently permit longer-term capacity to be sold only in quantities related to the capacity of the link without regard for netting out flows by direction.

[5] *We apply a typical common standard rather than the slightly varying standards that exist from country to country.*

This issue becomes particularly significant in a world where the directions of movement of electricity across borders will become much more variable, as a result of increasing quantities of intermittent renewable generation. The main impediment to the achieving a long term trade in energy in Europe is the use of physical capacity rights for trading transmission capacity. Reform, for example, along the lines of using financial transmission rights, is required to deliver the necessary flexibility in usage of transmission capacity.[6]

In the shorter term, where the technologies of generation are dominated by fossil fuels and nuclear power, the social costs of an energy neutral approach are fairly small. This is because there are not significant locational advantages to generation by these technologies in Europe. In general, with these technologies, it is just as cheap to construct the power station close to the source of demand, and physically transport the fuel, rather than locate elsewhere and transmit the electricity long distance. But renewable sources of generation are much more sensitive to location in terms of their costs. Thus building them in geographically disadvantaged locations can be very costly.

The "energy neutral" scenario is clearly something of a simplification of the present situation, and as such using it as a baseline is likely somewhat to overestimate the benefits of moving to an integrated scenario. However it is also the case that a simplified grid model will tend to underestimate benefits, so these factors may offset to some degree.

In addition to those two policy scenarios, we consider a number of further changes to the level of integration in the market. For completeness, we show the complete list of policy scenarios we are considering below:

- <u>Baseline</u> The baseline scenario takes the market scenario (CPI, RES – see below) and provides such additional generation such that energy neutrality is observed, ie, each national market has within it the basic generation capacity to satisfy its own energy needs, and only trades to achieve short-term arbitrage. The PRIMES scenarios in fact do not deviate materially from energy neutrality.

- <u>Integrated market</u> In this scenario the basic requirements of a fully integrated market are provided for. Optimal levels of transmission will be built, because it is commercially and economically desirable to do so in a properly integrated market. Security of supply will be shared across boundaries. Balancing arrangements are still provided for within each separately managed transmission system, and there is no increased provision for peak reduction by demand management.

- <u>Integrated with Low TX</u> In this scenario, integration is reduced from the basic integrated case because of a lack of development in network access or insufficient cross-border transmission investment. In this scenario, only 50% of optimal new transmission capacity is constructed, but no link is reduced by more than 5GW. However, whatever methods achieved the market integration of the Integrated scenario continue.

- <u>Integrated but Self-Secure</u> In this scenario, integration is reduced from the fully integrated case because nations explicitly provide for their own short term security

[6] *See "Physical and Financial Capacity Rights For Cross-Border Trade", 2011, Booz & Co, D Newbery and G Strbac, available at http://ec.europa.eu/energy/gas_electricity/studies/electricity_en.htm*

of supply at a member state level. Security of supply refers to having sufficient spare capacity to be able to deal with the risk of major plant outages without involuntary demand shedding, to the standard of a maximum of 2 hours load-shedding per year. Otherwise the methods of the Integrated scenario are used.

- Integrated with EU Reserve In this scenario, integration is increased further by making some sharing of various balancing services between countries. Balancing services are very short term adjustments in supply to maintain voltage and frequency, excluding the effect of major plant outages. Otherwise the methods of the Integrated scenario are used.

- Integrated with DSR In this scenario, Demand-Side Reduction (DSR) is facilitated by demand management techniques, made possible by adoption of smart grid technologies. By encouraging low-value users to curtail demand at peak times, the quantity of generation capacity required is reduced. For this scenario, we make the assumption that up 10% of daily energy is flexible, and 15% peak load reduction can be achieved. Although it is an EU requirement to fit smart meters that will technically allow widespread demand side reduction, further developments are required to enable it to be implemented. If a supply and balancing capacity market is implemented then commercial incentives to implement demand management may be weakened.

We will also construct a scenario for 2015 on the basis of the 2015 PRIMES scenarios, as the closest available approximation to the 2014 date. The 2020 and 2030 PRIMES scenarios have been provided to us in a form which has additional calculations already performed, but not the 2015 scenario. We will modify the 2020 scenario to give a reasonable approximation of the 2015 scenario.

There may be some concern that our Baseline scenario assumes that the optimal quantity of transmission capacity is constructed, and, given environmental concerns and the need for political will, the optimal amount of transmission capacity may not be constructed. We have constructed a sensitivity to show that this is not a large issue. We have considered a variation to the CPI 2030 Baseline case where only half of the optimal transmission capacity (half of the increment from today's level) is built. (This is similar to the Integrated with Low TX scenario we consider, except that it otherwise follows the Baseline case.) This has a reduction of economic benefit relative to the Baseline scenario of €2.6bn per year. This is relatively modest amount in comparison to the benefits of integration indicated the robustness of our results. We can further observe that in our 2020 cases, ENTSO-E's planned transmission capacity increase is adequate in all of those cases. The ENTSO-E 2020 plan is not far short of 50% of the 2030 optimal quantity of transmission in each of the cases we study (the Low TX case aside). This provides a degree of comfort, conditional upon there being some continued progress in building the desirable transmission capacity.

Case Study E2: PJM Interconnection

The PJM Interconnection is an integrated grouping of several local transmission markets in the central eastern part of the UK, covering about 51 million people from Chicago to Philadelphia, consuming around 730TWh per year. It lies within the Eastern Interconnection, one of the two separate power grids of the USA. The quantity of renewable energy in the PJM area is rather low by US standards, since this is not a favourable region for renewable generation.

Two particular points of interest arise for the present study:

- PJM indicates the feasibility of implementing methods of full market integration across independently operated grids, in contrast to the partial integration methods of the Target Electricity Model in Europe.
- Studies of the expansion period of PJM in 2002-5 offer a quantitative measure of the benefits of that integration.

PJM is operated as a Locational Market Pricing (LMP) market, which means each node of the system has a separate nodal price in each dispatch period, calculated in an algorithm that facilitates perfectly efficient dispatch. The PJM, like all US markets that operate under Locational Market Pricing (LMP), offer transmission capacity structured as Financial Transmission Rights – ie, it amounts to an insurance product, or contract for difference, representing the price difference between the two nodes it is specified for. FTRs facilitate a truly integrated market for energy across borders between the supply areas, as if the traders were trading within a supply area.

The reason that FTRs have this effect is that it makes the traders indifferent between the actual transmission of their electricity between the two nodes, or trading locally if they are constrained off in the actual despatch. These FTRs are constituted as obligations to pay, since a bid to transmit may be offset against another entities transmission in the other direction, allowing netting to occur. This allows the total volume of trade to exceed the volume of the link, while netting to a feasible net amount. This is a necessary property of a truly integrated market across supply regions, and indicates the feasibility of what is currently not possible in Europe.

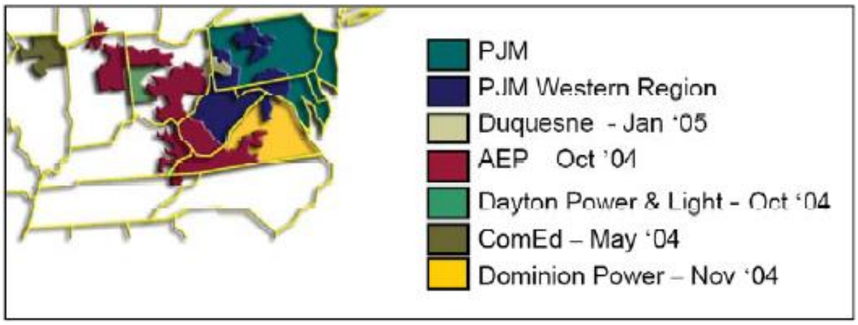


Figure: PJM Expansion 2002-2005

*I*n 2002-5, the PJM underwent a series of expansions from its original area covering of 21 million people, to its present day 51 million population area, joining 5 previously separated transmission areas into its scope. This is broadly equivalent in scope to integrating the electricity markets of several small to medium EU countries. A study found that the efficiencies resulting from the change were of the order of 2.5 times larger as a result of the PJM Interconnection's highly integrated approach (LMP, FTRs), as opposed to bilateral trading methods (Mansur and White, 2012). The annual net economic benefit estimated is $180million, or 0.45% of the value of the electricity generated (at wholesale price). The savings to customers are estimated at about $500million/year (1.25% of electricity). The fact that this is larger than the pure efficiency saving suggests that there has been enhanced competition reducing prices. These savings are quite modest in comparison with the integration benefits we estimate in for Europe. But it should be understood that a degree of integration already existed within the broader framework of the Eastern Interconnection. Also the generation mix of the linked states is much more uniform, and transmission despatch methods also, than across Europe, so the potential gains from improved integration of trade in this area were never as large as they might be in Europe.

3.4 MARKET SCENARIOS

3.4.1 Gas

The 2012 "Base Case" is based on actual supply and demand data, as well as on current existing infrastructure. Also for Scenario 1 we assume actual 2012 demand data. To enable comparisons between scenarios we have not considered the impact on gas consumption of border price changes. Consumption in residential and industrial markets is relatively price inelastic, and consumption in power generation is already generally depressed, due to the (priority) dispatch of power generated from renewable sources, and the current price levels of coal and CO2. However, policy is expected to have had an effect on how demand would have been satisfied (through supply and network capacity). We will assume that supply and network capacity would have been sufficient, given liberalisation and market integration within national borders, but no cross-border integration.

For the Scenarios 2 and 3, we rely on demand, supply and network development data from both PRIMES and ENTSO-G, where PRIMES prevails over ENTSO-G when both sources provide data on the same variables. PRIMES provides annual natural gas demand outlooks up to 2050, and is also the main source of input for the part of this study on benefits of integration in power markets. To ensure consistency with that part of this study, we use the PRIMES "CPI" ("Current Policy Initiatives") scenario to determine demand information. PRIMES also provides information on production levels of natural gas until 2050 across European member states. As PRIMES data does not include maximum daily demand, we rely on ENTSO-G for this information. In addition, we use ENTSO-G Ten Year Network Development plans (TYNDP) for network development data. For both daily demand and network development data, ENTSO-G provides a 10-year outlook for the period 2013-2022 for each EU27 member state (published February 2013). The information of ENTSO-G factors in the effects of the implementation of the EU's "Third Package", and is assumed compatible with the PRIMES information.

3.4.2 Electricity

For our analysis, two generation and demand backgrounds developed based on PRIMES scenarios for year 2020 and 2030 will be used. These two main scenarios are: (1) Current

Policy Initiative (CPI), (2) High Renewables (RES).[7] We have additionally used a common 2015 scenario. We have developed, for 2030 only a further scenario we call Renewables Investment Coordination (INV).

In order to evaluate the benefits of coordinated and efficient investment in renewable power across Europe, one modified scenario based on the 2030 High Renewables scenario will be developed by re-allocating renewable power, particularly wind power and PV, with low load factors to locations with higher load factors.

Since the model contains more detailed representation of geographic locations compared to PRIMES data, some assumptions have been taken to allocate generation resources and demand following the same patterns that we have at present.

Current Policy Initiative (CPI) scenario

The CPI scenario was built using the same macroeconomic framework used by the "Reference scenario"[8] but includes the policy initiatives adopted after March 2010 or policy initiatives currently being planned as well as updated technology assumptions for the uptake of electricity vehicle and development of nuclear power industry following the Fukushima accident. Details of the CPI description can be found in the European Commission's Energy Roadmap 2050 document.[9]

For our analysis, the CPI scenario will be used as a reference scenario.

By 2020, the system peak demand will be 633 GW with the annual system consumption of 3650 TWh.[10] The contribution of each generation technology[11] in supplying demand is summarised in Figure 3.3 (a). It is shown that the coal fired plant is still the largest contributor (27%) to the overall supply. These results are driven primarily by relative fuel prices for coal and low carbon prices in 2020 (€15/t CO2). Nuclear power is the second largest contributor by supplying 26% of total electricity consumption. Wind, both on-shore and off-shore, and PV contribute 15% and 2% respectively to the supply. Renewable curtailment is relatively low (below 1%) and the emissions from the grid are approximately 285 g/MWh.

By 2030, the system peak demand will increase to 664 GW with the annual system consumption of 3833 TWh including losses. The contribution of each generation technology in supplying demand is summarised in Figure 3 (b). The contribution of coal fired plant is slightly more than half of its contribution in 2020. These results are driven mainly by high carbon prices in 2030 (€32/t CO_2). Contribution from nuclear power is slightly down from 26% in 2020 to 22% in 2030 but it becomes the largest contributor. Wind, both on-shore and off-shore, and PV contribute 21% and 3% respectively to the supply. Renewable curtailment is low (0.3%) driven by high carbon prices and the average emissions from the grid are down to 200 g/kWh.

---

7 *European Commission, "Energy Roadmap 2050", Brussels, 15 December 2011*

8 *The Reference scenario was used in the analysis for the "Low-carbon economy 2050 roadmap" and "White Paper on Transport". The Reference scenario is a projection of developments following the policies before March 2010.*

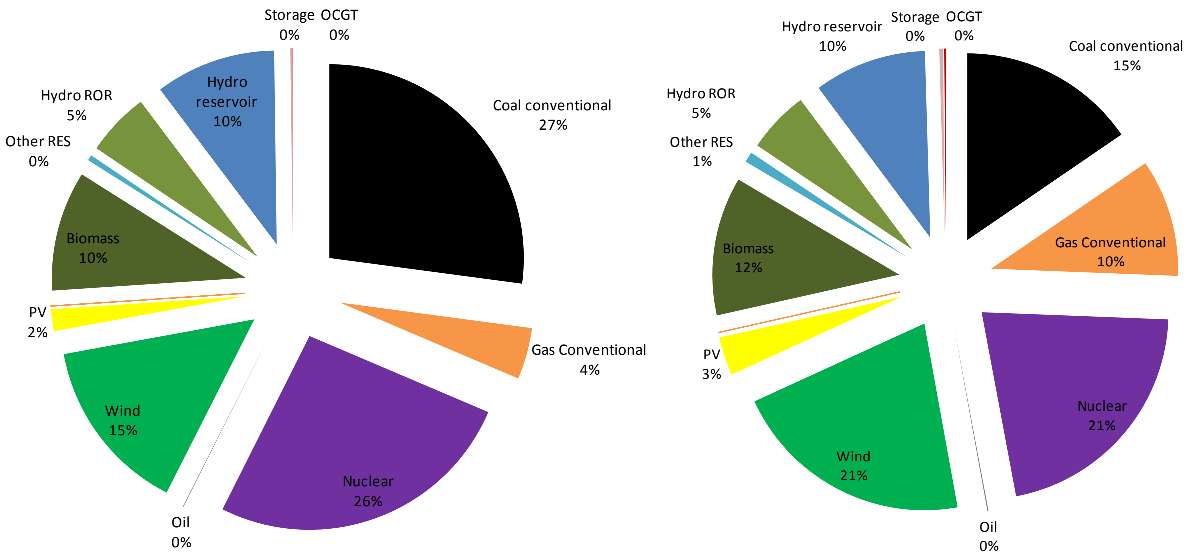
9 *http://ec.europa.eu/energy/energy2020/roadmap/index_en.htm*

10 *The figure includes transmission and distribution network losses.*

11 *The annual energy of each generation technology is calculated by DSIM based on the cost minimisation formulation.*

Figure 3.3 shows the annual electricity output of each generation technology and the peak demand at each region in 2020 and in 2030 respectively. It can be seen that the majority of regions are either importing or exporting areas indicating the importance of power exchanges across regions.

We have also used the CPI 2015 scenario.



(a) 2020 (b) 2030

Figure 3.3 Electricity supply in CPI scenario

Figure 3.4 shows the total installed capacity of each generation technology by 2020 and 2030 in CPI scenario. The installed capacity of OCGT has been optimised such that the total installed generation capacity, including renewable power, is adequate to maintain security of supply.[12] In this scenario, the capacity of coal, gas, and oil fired plant in 2030 will be reduced by 30% in ten years while the installed capacity of wind power increases by 45% and the PV capacity is double. The capacity of hydro plant and storage will be practically the same although there is going to be new investment in small Run of River (RoR) type hydro plant. As a consequence of increased penetration of renewable power and reduction in coal, gas, oil fired and nuclear power plant, the installed capacity of OCGT needs to increase by 2030 to maintain the same level of reliability.

12 *The security is measured using the Loss of Load Expectation (LOLE) approach. The LOLE index indicates the number of hours in one year operation where electricity load in the respective system exceeds the total installed generation capacity, which may include support from neighbourhood region.*

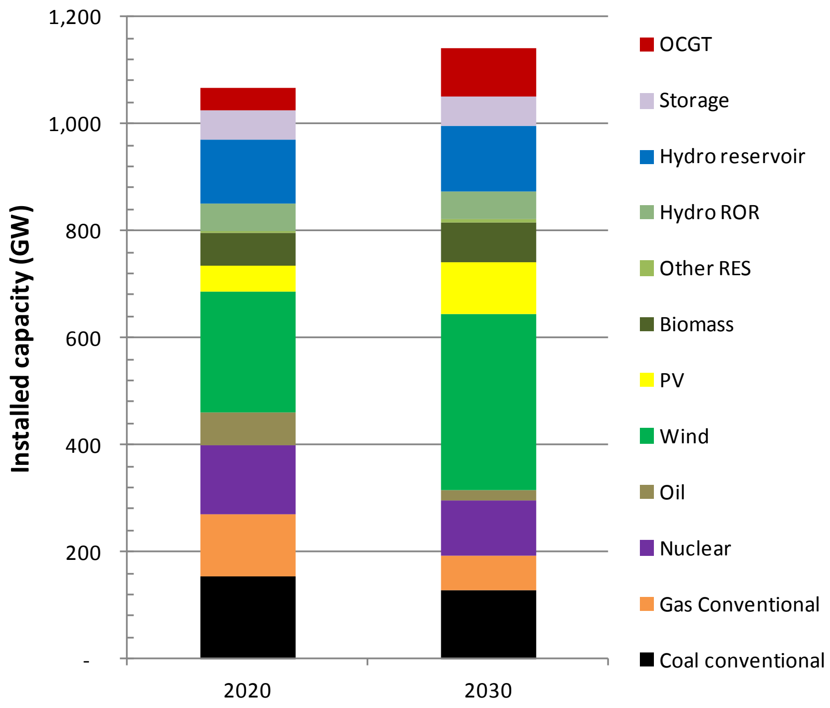


Figure 3.4 Installed electricity generation capacity in CPI scenario

High Renewable (RES) scenario

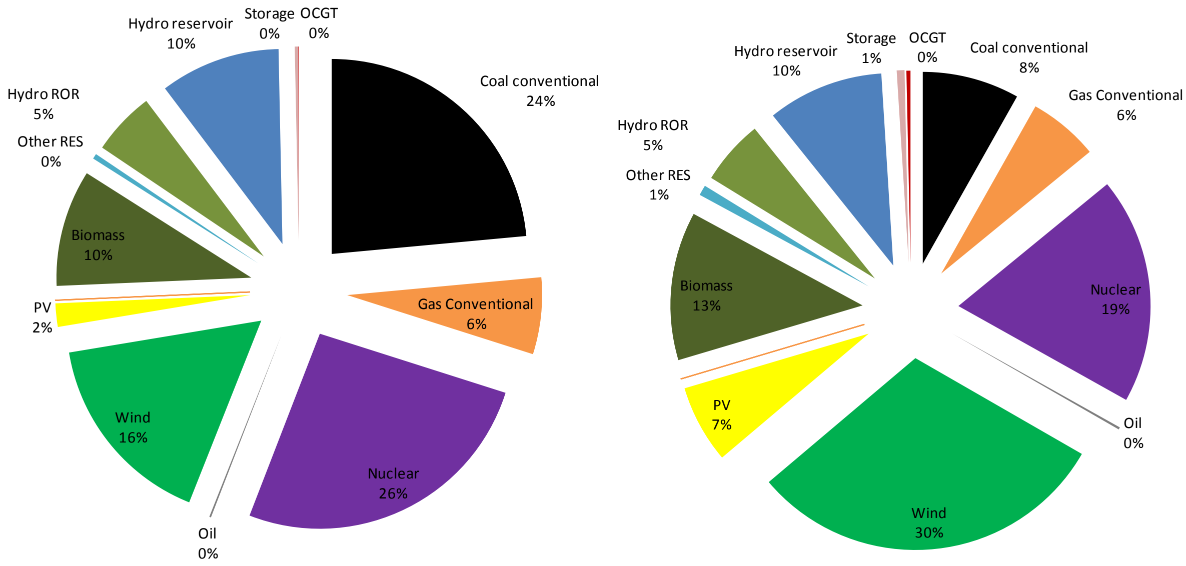
The High RES scenario aims at achieving a higher contribution of RES in supplying electricity demand by a significant increase in the installed capacity of wind power and PV generation.

By 2020, the system peak demand will be 640 GW with the annual system consumption of 3681 TWh. The contribution of each generation technology in supplying demand is summarised in Figure 3.5(a). Nuclear has the largest share in power generation (26%) and followed by coal fired plant (24%). These results are driven primarily by relative fuel prices for coal and low carbon prices in 2020 (€25/t CO2), though higher carbon prices than in the CPI scenario. Wind, both on-shore and off-shore, and PV contribute 16% and 2% respectively to the supply. Renewable curtailment is relatively low (~ 2%)[13] and the emissions from the grid are approximately 260 g/kWh.

By 2030, the system peak demand will increase to 662 GW with the annual system consumption of 3834 TWh including losses. The contribution of each generation technology in supplying demand is summarised in Figure 3.5(b). There is a significant reduction in the contribution of coal fired plant. It is down from 24% to 8% in ten years as the carbon prices increase to €35/t CO2. The contribution from nuclear power is down from 26% in 2020 to 19% in 2030. Wind, both on-shore and off-shore, and PV contribute 30% and 7% respectively

[13] *Among other factors, transmission constraints affect the amount of renewable power that needs to be curtailed for network flow management. All 2020 scenarios use the present network capacity plus the reinforcement capacity proposed by ENTSO-E, while for the 2030 scenario, transmission capacity is optimised by DSIM for each specific scenario resulting to more optimal built.*

to the supply. Wind power has the largest share in electricity supply by 2030. Renewable curtailment is low (1.2%) and the average emissions from the grid are down to 115 g/kWh.



(a) 2020 (b) 2030

Figure 3.5 Electricity supply in RES scenario

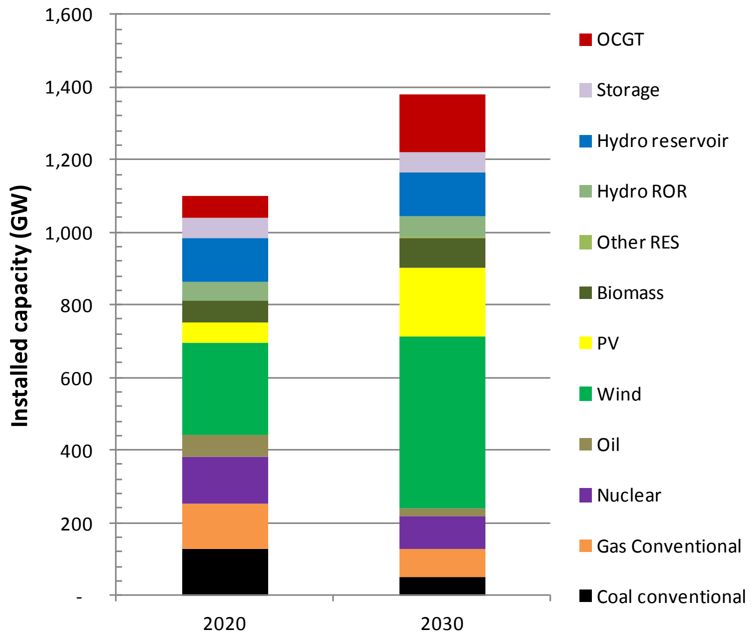


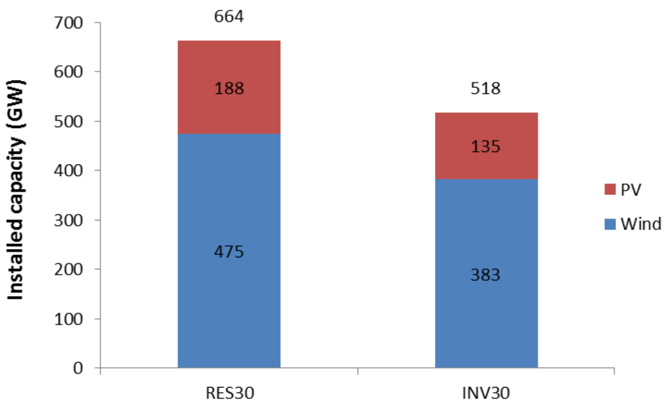
Figure 3.6 Installed electricity generation capacity in RES scenario

In this scenario, the capacity of coal, gas, and oil fired plant in 2030 will be reduced by approximately 50% in ten years while the installed capacity of wind power increases by 87% and the PV capacity increases more than threefold. Nuclear capacity is reduced by 26% but the capacity of hydro plant and storage will practically be the same. As a consequence of increased penetration of renewable power and reduction in coal, gas, oil fired and nuclear power plant, the installed capacity of OCGT needs to increase by 2030 to maintain the same level of reliability. For the 2015 we use a common scenario (see CPI above) since material differences in scenario by 2015 are unlikely.

Renewables Investment Coordination (INV) scenario

We have additionally constructed a further scenario for 2030 (only), the motivation for which is the observation that much of the renewables capacity in the RES scenario will suffer poor load factors because of its unfavourable geographical location. It would be possible to construct much of this capacity in more geographically favourable locations, and thus, through the improved load factor achieved, produce the same amount of energy from less capacity. In our INV[14] scenario we achieve a saving of 146GW of capacity, without reduction of output, through this relocation. Figure 3.7 shows this in aggregate. Figure 3.8 shows how much less wind and PV capacity is built in parts of Germany, for example, while transferring wind to westerly maritime regions, and PV to the south.

In a fully integrated market, there should be a natural economic incentive to construct capacity in favourable locations, to the extent that such are not distorted by market interventions such as non-neutral local subsidies and quotas. To achieve this, the Renewables Directive needs to be implemented so as to achieve its aims, i.e., a common market in renewable generation capacity.



Coordinated new wind and new PV deployment
→ saving 146 GW of new capacity
- Wind in the North
- PV in the South

In TWh	RES 2030	Coordinated
Coal conventional	352	347
Gas Conventional	333	338
Coal CCS	0	0
Gas CCS	0	0
Nuclear	731	731
Oil	8	9
Wind	1169	1168
PV	252	252
CSP	0	0
Biomass	333	333
Geothermal	33	33
Hydro ROR	210	210
Hydro reservoir	374	374
Storage	23	25
Other RES	0	0
OCGT /back-up	14	13
Total electricity production	3832	3834

Figure 3.7 Adjustment of the RES 2030 scenario to form the INV 2030 scenario

[14] *This is our own scenario, not a PRIMES scenario.*

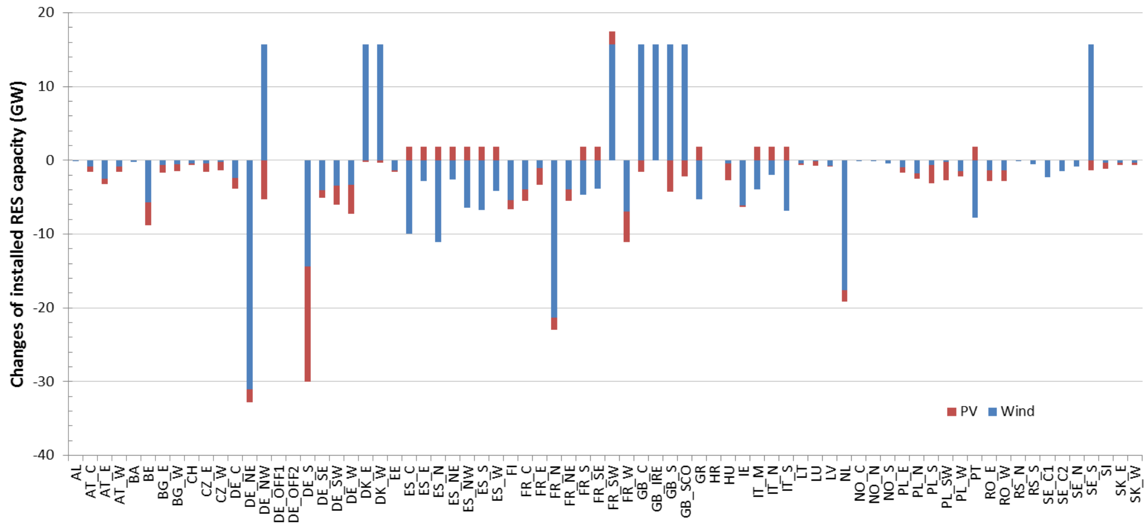


Figure 3.8 Locational adjustment of PV and wind from RES 2030 to INV 2030

Additional data for modelling of PRIMES scenarios

The model that is used depends upon input that is acquired by taking a PRIMES scenario and processing it alongside other data to produce a richer description, and put in a form that is suitable for input to the model. As a result of prior work, we are in possession of this additional data and outputs for PRIMES scenarios for 2020 and 2030. For our (common) 2015 scenario we have made some interpolation from the 2020 data.

4. GAS MARKET – FINDINGS

4.1 DETAILED SCENARIO DESCRIPTIONS

To determine benefits in terms of "Price" and "Security of Supply" in our scenarios as defined previously, it is important to establish a baseline of where European countries stand today in terms of degree of liberalisation and integration – this baseline is in fact our Base Case. To establish the baseline, we have assessed the level of maturity of liberalisation and integration across EU27 member states in four dimensions:

- Market liquidity: the existence of, and volume traded on trading hubs
- Competition at the border: number of competing natural gas importers in a country
- Price formation of border gas: the proportion of oil-indexed vs. hub-based prices in border gas prices
- Physical and trading integration: physical connectivity across markets and price convergence

The following sections summarize the main insights from this assessment, and subsequently provide a description of our "Base case" and the three scenarios.

4.1.1 Market liquidity across Europe

Over the past years, multiple gas trading hubs have emerged across Europe. The first European gas trading hub to be established was the "National Balancing Point" in the UK, in 1996. In subsequent years, hubs (both physical and virtual) were established in continental Europe, e.g. Belgium (ZEE), Germany (Gaspool; NCG), the Netherlands (TTF,), Italy (PSV), and France (PEG-Nord and PEG-Sud). More recently, some Eastern European countries have established hubs, e.g. the VTP in the Czech Republic, and the MGP in Hungary. Varying churn ratios[15] across the more established hubs indicate that liquidity levels differ significantly across markets (see Figure 4.1). Currently, only the British NBP and Dutch TTF are generally considered to be "liquid" hubs.[16]

4.1.2 Competition at the border

To estimate the level of competitiveness in markets, we determined the number of players actively importing gas into a market. The number of importing players is an indicator of the choice that gas wholesalers have regarding suppliers. If there is one dominant importer, wholesalers have little other choice than to source gas from this one party. Competition at the border (and therefore presumably the strength of competition in the corresponding wholesale markets) varies across EU27 member countries.

---

[15] *Measure of market liquidity, calculated as the total traded volume / physical volume traded*

[16] *Based on the notion that hubs are considered liquid if they have a churn ratio above 10 (Source: Oxford Institute for Energy Studies (OIES), P. Heather "The Evolution and Functioning of the Traded Gas Market in Britain", August 2010)*

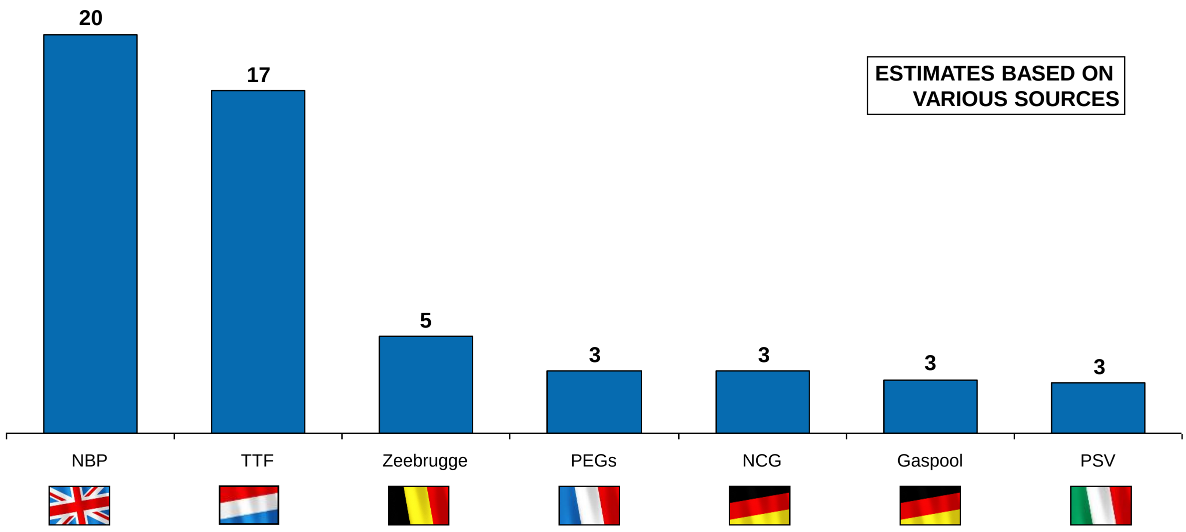


Figure 4.1: Churn Ratios Main European Gas Hubs (2011)

Notes: Estimates based on various sources
Source: ICIS Heren, IEA, TSO data, GTS, Oxford Institute of Energy Services "Continental European gas hubs: are they fit for purpose?", June 2012, p. 6, Booz & Company Analysis

4.1.3 Border prices

We use the price formation mechanism of border prices as one of the dimensions to determine the maturity level of liberalisation and integration of a national market. For example, in a market where border prices are close to hub prices, prices in wholesale markets are likely predominantly driven by supply / demand dynamics. If we take the UK as an example, it is evident that border price levels are more closely related to hub prices than to oil-indexed prices (see Figure 4.2). Several European markets in 2012 were characterised by border prices that can be described as a mix of hub and oil-indexed prices. We have assessed country-by-country for the EU27 member states the indicative make-up of border prices (see Figure 4.3). From this analysis it appears that while in some countries prices are fully or partially driven by hub prices, most countries have border prices that are close to oil-linked prices.

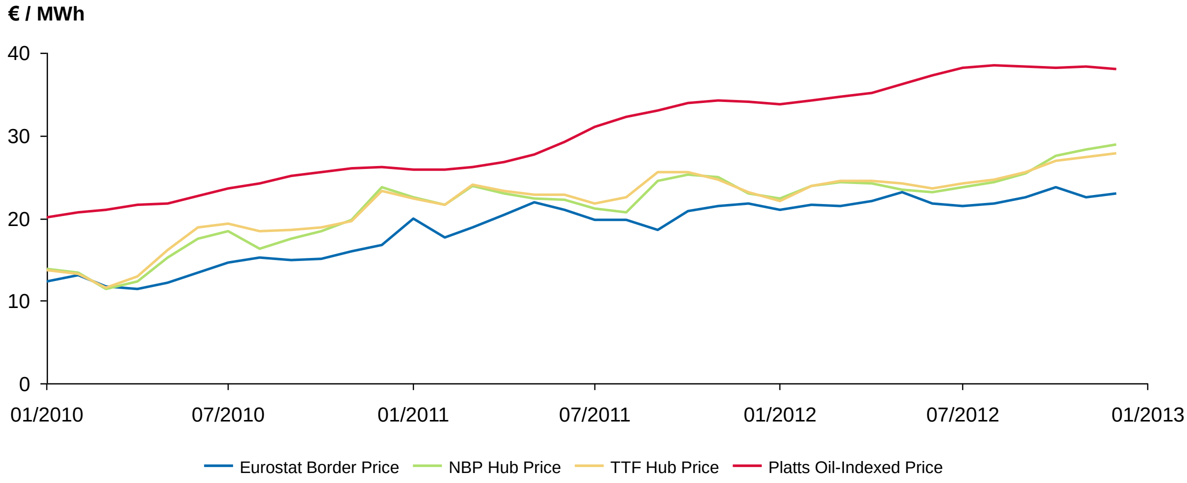


Figure 4.2: Monthly Border Price and Price Indicators, UK (2010-2012, in €/MWh)

Notes: Average Border price is based on total value of import / total volume imported per month (Eurostat data)
Hub prices based on Month-ahead prices from Bloomberg

Source: Eurostat, Platts, Bloomberg, Booz & Company Analysis

Figure 4.3: Price Mechanisms for Border Prices per EU27 Member State (2012)

Note: Location on graph based on country-by-country assessment of average border prices vs. hub and simulated oil-indexed contract prices, and expert market insights. Cyprus and Malta not included in overview (no gas consumption in 2012). Netherlands is not included as domestic production is the main source of supply

Source: Eurostat, Bloomberg, Booz & Company Analysis

4.1.4 *Integration*

To achieve integration of gas markets, sufficient physical cross-border connectivity is required. Physical cross-border connectivity within the EU today is more developed in NW-Europe than in the rest of Europe (see Figure 4.4). This physical connectivity in NW-Europe has allowed effective trading to develop between these countries, and has resulted in price convergence across its gas hubs (see Figure 4.5). This integration of NW-European markets was also confirmed by the literature reviewed in Section 2.2. Market integration between European markets other than NW-European countries is not apparent as of yet.

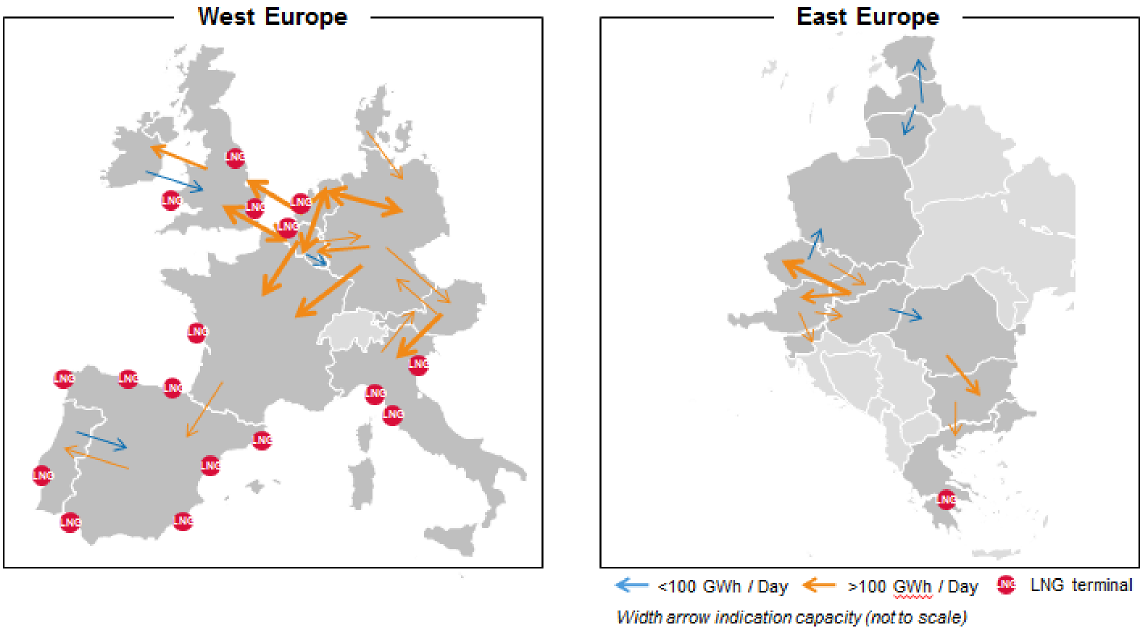


Figure 4.4 Physical Cross-Border Connectivity Europe (2012)

Note: Only includes main pipelines reported by ENTSO-G as "cross-border" and between EU27 member states
Source: ENTSO-G Capacity map & Database 2012 (updated May 2012), ENTSO-G TYNDP 2011-2020, Booz & Company Analysis

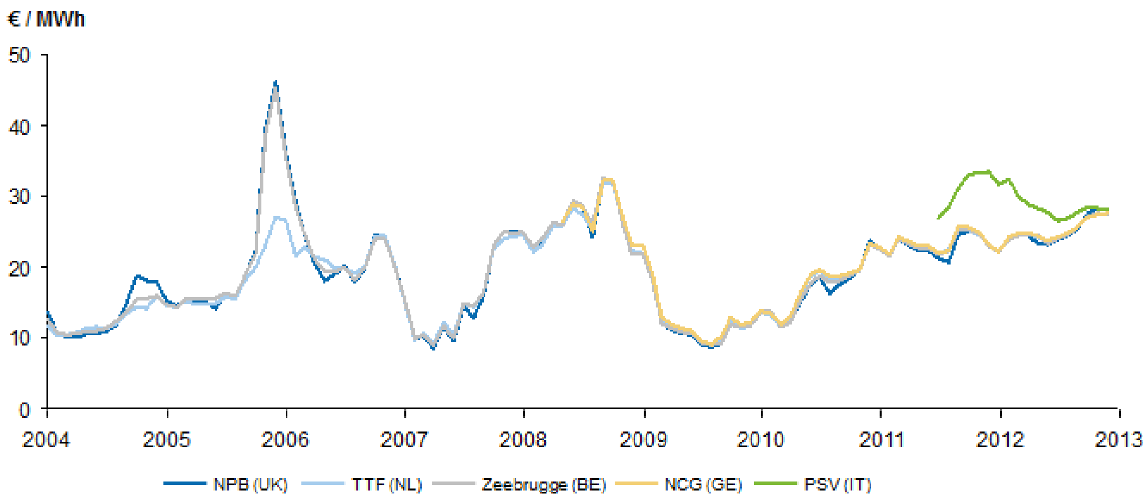


Figure 4.5: Price Convergence North-West European Hubs (2004-2012, in €/MWh)

Note: Prices are monthly averages of Month-Ahead prices
Source: Bloomberg, Booz & Company Analysis

4.1.5 *Scenario descriptions*

Based on the assessment of the four dimensions of market liberalisation and integration maturity presented above, we have ranked the EU27 member states (see Figure 4.6). The current European market in 2012 (Base Case) consists of a mix of markets in terms of maturity of liberalisation and integration, with some markets well advanced, whilst others are at an earlier stage in the process.

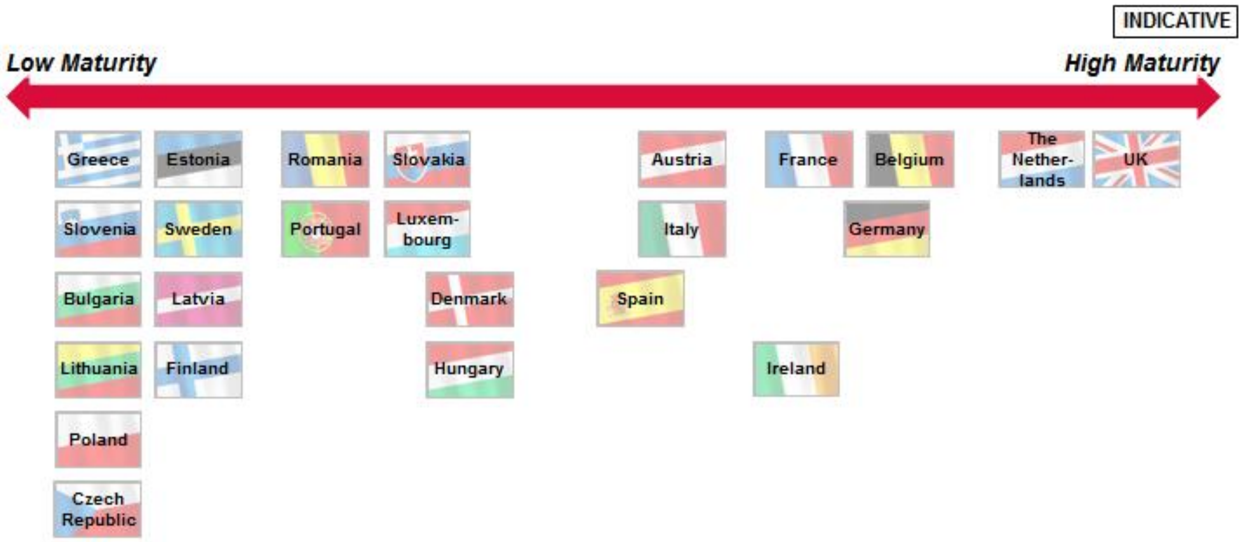


Figure 4.6: EU27 Maturity of Market Liberalisation and Integration (2012)

Note: Malta and Cyprus excluded (no gas consumption in 2012)
Source: Booz & Company Analysis

To make the various scenarios easily comparable to the Base Case, we describe the state of the gas market in the base case and the three Scenarios (as described in chapter 3) along five parameters: "Unbundling", "Third Party Access" (TPA), "Flexibility", "Connectivity", and "Hubs". Table 4.1 provides a detailed overview of our starting point for the Base Case and the assumptions underlying the various scenarios. Scenario 1 "2012 No Integration" is a hypothetical situation in which the different European national gas markets operate largely as islands that import gas through long-term oil-indexed contracts without any meaningful cross-border trading. Scenario 2 "Mid-State" is a situation in which the European market consists of a number of regions that are in varying stages of maturity of liberalisation and integration. Within regions, there is integration of national markets, but between regions the level of integration is limited. This is primarily due to the limited interregional interconnectivity, although other factors may play a role as well. It is assumed in Scenario 2 that interconnectivity will grow primarily in Western Europe.[17] Finally, Scenario 3 "Full Integration" is a situation in which the European market is fully integrated and operates as the equivalent of a "copper plate" in electricity markets with one relevant hub price signal valid throughout EU27 (other hubs may exist that are 'priced-off' this main hub, a situation not unlike the current US gas market with Henry Hub providing the dominant price signal for regional hubs throughout the country).

Table 4.1: Scenario Assumptions

Parameter	Base Case	Scenario 1 "2012 No Integration"	Scenario 2 "Mid-State"	Scenario 3 "Full Integration"
Unbundling	- TSO unbundling has taken place in some markets driven by (EU) regulatory initiatives	- TSO unbundling has not taken place in any market other than the UK - Large incumbents	- TSO unbundling has taken place across all markets - Existence of dominant incumbent	- All TSOs are unbundled - There are multiple players active in each member

17 *Based on ENTSO-G Infrastructure capacity projections for 2015 (ENTSO-G TYNDP 2011-2020 and 2013-2022)*

Parameter	Base Case	Scenario 1 "2012 No Integration"	Scenario 2 "Mid-State"	Scenario 3 "Full Integration"
	- Large incumbents dominate some markets, while others have competitive wholesale markets	dominate the market imports, infrastructure and distribution	is expected to persist in East European markets	state, without any player being dominant
TPA	- There is third party access enforced through EU and national regulations - Any relevant party can gain access to infrastructure	- There is no obligation for third party access - Incumbents can hoard capacity and block new players from accessing infrastructure	- All infrastructure is operated under TPA (except those with agreed exemptions) - There is no limitation to capacity access for any player in any EU member state	- All infrastructure is operated under TPA - There is no limitation to capacity access for any player in any EU member state
Flexibility	- There are multiple sources of flexibility (e.g. storage, import swing, LNG, "virtual storage") - Flexibility in liberalized markets is priced based on summer-winter spreads, whilst in other markets price is cost-plus based	- Flexibility is supplied primarily from local storage close to end consumers - Any existing hubs are not a meaningful source of flexibility; price of flex is cost-plus based	- Flexibility is supplied through a mix of storage, LNG, on import / production swing and hubs - Flexibility is optimized at regional, rather than EU level	- Flexibility is supplied through a mix of storage, LNG, import swing, and through hubs - Flexibility is optimized at EU27 level
Connectivity	- There is cross-border connectivity, primarily in North-Western Europe - Limited cross-border connectivity in other parts of Europe or between West and East	- There is limited cross-border interconnectivity other than to secure imports - There is no physical capacity for trading	- Interconnectivity across markets has increased vs. 2012, but primarily at regional level - In particular trade between Eastern, and Western Europe remains limited	- The EU27 market is fully physically integrated and operates as a "copper plate" - Gas can flow freely between all member states
Hubs	- There are liquid hubs in the Netherlands and UK, and several other less mature, but growing hubs - Most countries (primarily Eastern / Southern Europe) do not have a trading hub	- No liquid hubs for trading that provide meaningful price signals (except for NBP in UK) – any existing hubs are serve optimization and balancing - Gas is supplied solely through long-term oil-indexed contracts	- West European trading hubs are mature, and hubs are emerging in other areas - Hub prices have gained in importance as price signal but are not the only signal in the market across EU27	- There are multiple established trading hubs across Europe - The prices at the hubs have converged and is the only price signal in all EU27 states

Source: Booz & Company

4.2 INTEGRATION BENEFITS : PRICE

4.2.1 *Benefits and methodology*

To identify benefit of market integration in terms of the price of gas, we would ideally have focused our analyses on wholesale prices. Consistent, comparable data on wholesale prices across EU27 are however difficult to obtain. Therefore, we use border prices as a proxy for wholesale prices in the respective markets. We consider border prices as good indicators for wholesale prices, as wholesale price levels are typically strongly dependent on border prices. As benefits of market integration in terms of gas price come about through changes in the price, we are not concerned with the absolute prices, but with the differences between the different scenarios (see Figure 4.7).

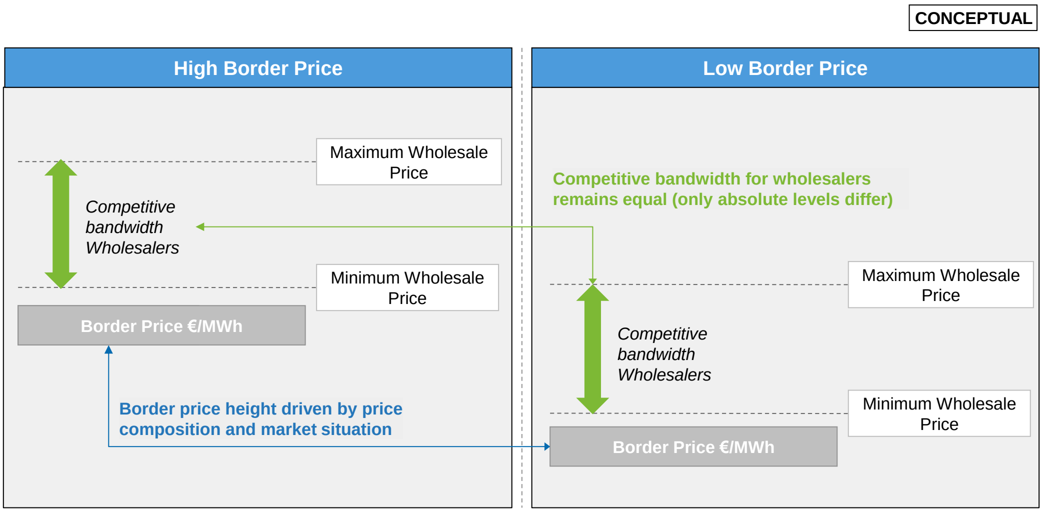


Figure 4.7: Border Prices as Indicator of Wholesale Price

Source: Booz & Company

We have identified three main potential effects of market integration on price.

The first effect concerns price levels. Under the different scenarios border prices will be different from today, and will differ between markets (except in Scenario 3 where all countries benefit from the same border price). Market integration creates economic benefits if it leads to lower border prices. This benefit is calculated as the difference between a country's border price in the base case and the border price in the each scenario, multiplied by gas demand under that scenario for each country. In 2012, Europe is in a situation of oversupply in which hub prices are lower than oil-indexed prices. If this situation continues, increasing market integration is expected to facilitate continued pressure on import prices, and *in extenso* on the actual price mechanism of indexation of gas prices to the prices of oil products. As market integration increases, the co-existence of these two prices gradually disappears until the situation of Scenario 3 "Full Integration" appears in which gas prices are 100% hub-based across EU27. To calculate the economic benefit from this gradual movement to hub-based prices, we base ourselves on 2012 averages of hub and oil-indexed prices, and apply the difference between the two across the scenarios. For each EU27 member state we assess the difference between current border prices and the assumed border prices under the three scenarios. In Scenario 1, we assume that border prices remain fully oil-indexed (at the average 2012 oil-indexed price). In Scenario 2, we define a mix of oil-indexed price and hub-prices specific for each country. Finally, for Scenario 3 we assume that all border prices equal the 2012 border prices in the UK, as a representative price marker for fully hub-based pricing. Again, all these assumptions on border price formation for the various countries are under the general market assumption of continued oversupply in Europe. (See Appendix A, Figure 7.1 for more details on methodology).

The second benefit of market integration in terms of "Price" concerns the price of flexibility. In countries where hubs are liquid, the value of flexibility is determined by market participants and finds its expression as the difference between hub prices in summer and in winter, the so-called "summer-winter spread". Traditionally however, the value of flexibility and therefore its price to market participants in Europe is determined by the actual cost of operating storage facilities through a "cost-plus" pricing methodology. As a result of market liberalisation and integration, hubs become more liquid and thus flexibility will be priced based on "summer-winter spreads", rather than "cost-plus" in an increasing number of markets. Current flexibility prices based on summer-winter spreads are significantly lower than "cost-plus" prices (see Figure 4.8). Therefore, an increase in liquidity at hubs would allow more players across Europe to access flexibility against lower prices based on summer-winter spreads, and benefit from the effects of market integration. The total benefit equals the difference in price multiplied by the required volumes of flexibility in a market. (See Appendix A Figure 7.2 for more details on methodology).

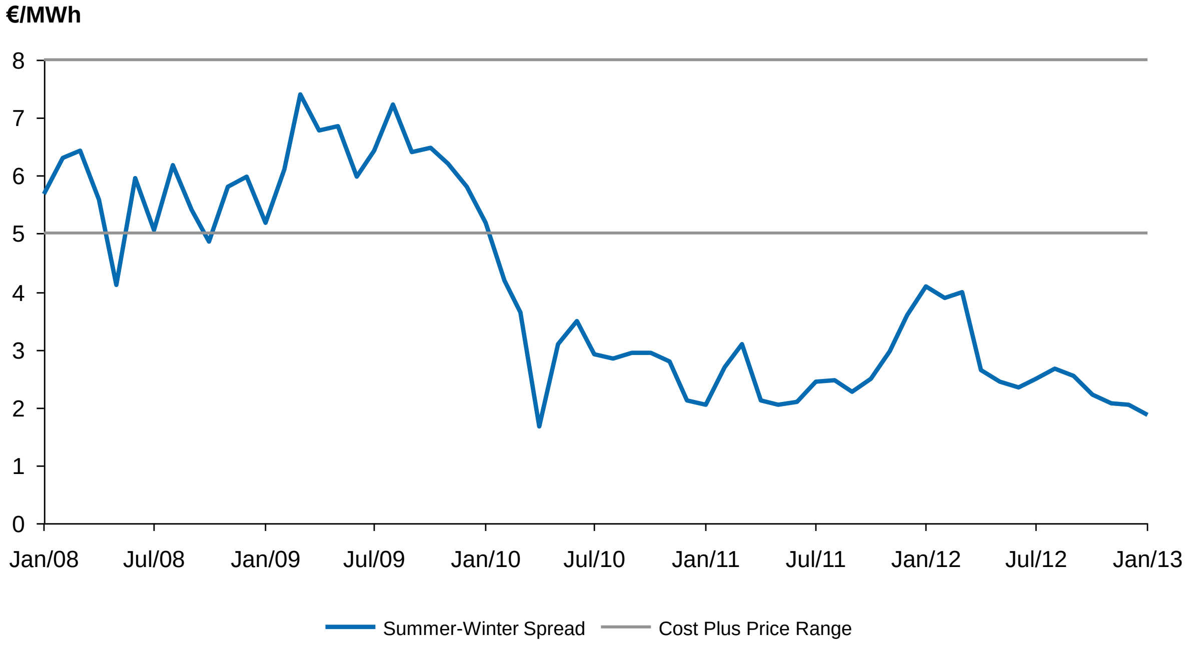


Figure 4.8: Monthly Average TTF Summer-Winter Spread (2008-2012, €/MWh)

1) Summer-Winter Spread equals monthly average of winter season ahead price - summer season ahead price at given date

Source: Bloomberg, Booz & Company Analysis

The third benefit of market integration in terms of "Price" concerns the prices paid for gas under long term contracts with minimum off-take obligations or so-called "Take-or-Pay" clauses, under which buyers are contractually obliged to take a minimum volume regardless of their ability to sell the volume in their end-markets. Historically, in a situation of (near-) monopoly, if an incumbent importer would find itself over-contracted it could pass on the additional cost to the market. With the emergence of hubs, players may be able to (partially) sell excess gas on the hub to other (international) parties. Therefore, hubs allow parties to recover (at least part of) costs incurred as a result of Take-or-Pay clauses. In the current market, hubs exist and parties have this possibility to sell excess gas. Under our general market assumption of continued oversupply, the relevance and liquidity of hubs will further grow in Europe. In Scenario 1 – where we assume there are no hubs that can meaningfully absorb excess volumes – parties would not have been able to sell excess gas at a hub, and would have therefore incurred more costs. So the benefit of market integration as it exists today versus a situation without any market integration or liquid hubs is the costs that could have been recovered by reselling excess gas at trading hubs. To quantify the benefit, a supply-demand balance per country was developed for those markets where gas can be sold at hubs in the base case scenario. (See Appendix A Figure 7.3 for more details on methodology).

Table 4.2 provides an overview of the three effects of market integration on price, and which effects will be quantified under which scenarios.

Table 4.2: Summary of Effects of Market Integration on Price per Scenario

	Scenario 1 "2012 No Integration"	Scenario 2 "Mid-State"	Scenario 3 "Full Integration"
Wholesale Price Differentials	- Countries that have hub-based border prices today import at oil-indexed prices - Impact is difference in price levels for those countries	- More states have hub-based border prices - Impact is difference in price levels for countries converted to hub-based prices vs. today	- All countries have hub-based prices - Impact is difference in price levels for countries converted to hub-based prices vs. today
Price Differentials in Flexibility	- Flexibility is sold at cost-plus based prices instead of summer-winter spread in selected countries - Impact is difference in price levels for those countries	- More countries enjoy hub-based flexibility prices instead of cost-plus based prices - Impact is difference in price levels for countries switched vs. today	- All countries enjoy hub-based flexibility prices instead of cost-plus based prices - Impact is difference in price levels for countries switched vs. today
Excess volume as a result of long-term Take-or Pay contracts	- Excess volume cannot be sold on trading hubs - Costs of excess volume is passed on to end-users	- n/a	- n/a

4.2.2 *Benefits Scenario 1 "2012 No Integration"*

Under Scenario 1 we assume that all markets have continued importing gas based on the long-term oil-indexed contracts. This is the case because competition at the border could not develop, and no pressure on oil-indexation could develop from an additional hub-based price signal in the market. Comparing that hypothetical situation to the Base Case, we find that in some markets price levels would have been higher than today under Scenario 1. This is the case for those markets that nowadays have border prices (partially) linked to hub price levels. From our methodology and assumptions, we estimate the maximum additional cost for gas supply under Scenario 1 at ~€21bn.[18] This is thus the estimated maximum benefit (or

[18] *Calculation based on the delta between border price 2012 and the oil-indexed price, multiplied by gas demand 2012. Denmark not included in the calculation due to very low volumes of import (no data on border prices). Spain not*

avoided costs) facilitated by market integration that Europe enjoyed in 2012. The benefit is the largest for markets that enjoy high levels of hub-indexed pricing in the Base Case and have high gas consumption, such as Germany and the Netherlands. As in the UK hub prices were prevalent already much earlier than on the Continent, we assume that UK price levels would have been the same in the Base Case and Scenario 1. Therefore, no benefits have been assumed for the UK here.

It should be noted that the size of this benefit is driven by the current difference in hub prices and oil-indexed prices. This size of this difference is not the effect of integration *per se* but is rather the result of, and is dependent on, the level of oversupply in the market..

The only countries in which flexibility prices against summer-winter spreads are apparent in the Base Case are the Netherlands and the UK. These are therefore the only countries that can be considered to be impacted by the effect of market integration on flexibility prices under Scenario 1. We assume that even if market integration had not arisen in NW-European gas markets, the cost of flexibility in the UK would have been determined by summer-winter spreads due to the fact that the NBP would have independently developed towards maturity and liquidity. Therefore, under Scenario 1 only in the Netherlands the cost of flexibility would have been different. Assuming prices for flexibility would have been determined on a cost-plus methodology and are comparable to today's price levels, we estimate the maximum additional costs that would have been incurred in 2012 in the Dutch market (and therefore the economic benefit) at €60-300mn[19] under Scenario 2.

To determine to what extent the EU27 benefitted from market integration in light of Take-or-Pay contracts, we performed a supply-demand balance analysis for those markets with access to a functioning trading hub in 2012. We found that Italy and France could have been faced with excess gas, as a result of demand falling below minimum Take-or-Pay levels in 2012. We estimate the maximum additional costs that these countries would have incurred at €6bn.[20] This calculation is hypothetical – we do not take into account what importers actually did do in 2012 to manage any oversupply (e.g. how much physical volume they did import and sold at hubs).

In summary, we estimate the maximum benefits facilitated by market integration in 2012 at €27bn. This value consists of the effects of market integration on the absolute gas price levels, on the price of flexibility and the effects of market integration on handling Take-or-Pay clauses in contracts. With approximately 500m inhabitants in EU27, this benefit translates to ~€50[21] per EU27 inhabitant in the year 2012.

included (current prices likely not driven by hub-indexation but successful renegotiation of long-term contracts and adjustments of P_0 values). Sources: Platts, Eurostat, Bloomberg, Booz & Company Analysis

[19] *Based on calculation of price difference between cost-plus based flexibility and summer-winter spreads 2012 multiplied by required flexibility volume in 2012 in the Netherlands (estimated as the sum of all monthly volumes above the average monthly demand). Sources: Eurostat, APX ENDEX, Booz & Company Analysis*

[20] *Based on minimum Take-or-Pay levels of 75% of contracted volumes, and the assumption that 50% of the excess volume could have sold against average month-ahead hub prices 2012, and 50% could have been renegotiated in the base case. Under Scenario 1, full minimum Take-or-Pay volumes would have to be purchased against oil-indexed prices without opportunity to sell at a hub or renegotiate Take-or-Pay levels. Sources: Contract Database Booz & Company, Eurostat, Platts, Booz & Company Analysis*

[21] *Based on 500 million inhabitants in EU27. Source: Eurostat*

4.2.3 Benefits Scenario 2 "Mid-State"

In Scenario 2 "Mid-State", most countries in Western Europe will have moved to partial or predominant hub-based pricing. This is based on the assumption that European markets will remain long or over-supplied, and the shift in border price formation to include increasing hub-indexation continues. Assuming that the difference between hub prices and oil-indexed prices remains at the level seen in 2012, these countries will enjoy lower gas prices as a result of the increase in hub-priced gas. Nevertheless, most EU27 member states will still see border prices based on oil-indexation, primarily countries in Eastern Europe, the Baltic States, and in Scandinavia. The shift of the markets in Western Europe towards increased importance of hub price signals in border prices results in a maximum economic benefit of €8bn in this scenario.[22]

To be able to benefit from flexibility prices set by summer-winter spreads, a market must have a truly liquid market. We believe that the time period to reach Scenario 2 "Mid-State" is too short to see a significant shift in flexibility pricing for most markets beyond the Netherlands and the UK. Hence, the benefits arising from lower cost of flexibility as a result of market integration are negligible compared to the benefits as a result of wholesale price reductions. Therefore, we do not consider lower cost of flexibility to provide a significant contribution to the overall benefits in the "Mid-State" scenario.

In summary, we estimate the maximum benefits of market integration by the time the Third EU Package is fully implemented versus the Base Case at €8bn per year (or ~€16 per EU inhabitant on average).

4.2.4 Benefits Scenario 3 "Full Integration"

In Scenario 3 "Full Integration", EU27 has evolved to one integrated market in which all gas is imported at hub prices. All base commodity price differentials between countries have disappeared and there is one price signal, i.e. the hub price, in the European market. A similar situation already exists in the US where prices across the country follow the price setting hub in the market, Henry Hub (see Case Study G1: US and Gas Price). The estimated impact of full conversion to hub-indexed prices is a maximum of €28bn[23] versus the base case, based on 2030 European gas demand profiles. The underlying assumption is that the current price differential between oil-indexed prices and hub prices is indicative for the benefit that arises from moving to full hub-indexed imports.

In the "Full Integration" scenario, we assume that all markets have access to flexibility against prices set by summer-winter spreads at the hub. This results in additional annual benefits of €0.5-2.6bn[24] versus the Base Case.

The maximum annual benefit that can be realized in the "Full Integration" scenario versus the Base Case is therefore €29-31bn. This translates to a total benefit per EU27 inhabitant of ~€60. It is important to note that we have used 2030 demand figures to calculate benefits of a fully integrated market. However, this should not be interpreted as a forecast of when we

[22] *Based on country-specific assumptions on mix of hub/oil-indexed prices for 2015, 2012 price levels, and 2015 PRIMES demand levels (Scenario CPI). Sources: Eurostat, Platts, PRIMES, Booz & Company Analysis*

[23] *Based on 2012 price levels, and 2030 PRIMES demand levels (Scenario CPI). Assumed price for 100% hub-indexed border price is the average 2012 UK border price. Sources: Eurostat, Platts, PRIMES, Booz & Company Analysis*

[24] *Required volume for flexibility is calculated by applying the flexibility necessary in 2012 (as % of 2012 demand) to demand levels in 2030 per country. Sources: Eurostat, Bloomberg, PRIMES, Booz & Company Analysis*

believe Europe will reach full market integration. This will depend on the development and implementation of regulation and market design across member states, as well as on behaviour of market participants

Case Study G1: US and Gas Price

The US had a natural gas consumption of ~690 bcm in 2011 (45% larger than EU27 2011 consumption). The US gas market has started deregulating in the 1970s, including unbundling of product supply, transportation and storage services, an approach also taken in Europe in the 2000s. The US gas market is a relatively mature market with one dominant price signal generated by Henry Hub in Louisiana. Henry Hub is the most liquid physical hub in the US, and prices at other hubs are priced off Henry Hub by “basis” or “location” differentials such as transportation costs (see Figure 4.9). Henry Hub evolved to become the price setting hub for the nation because the NYMEX (New York Mercantile Exchange) settled on Henry Hub as the delivery point for its future contracts in 1989. It was considered a suitable location at the time because it was a large, well-connected hub with abundant capacity.

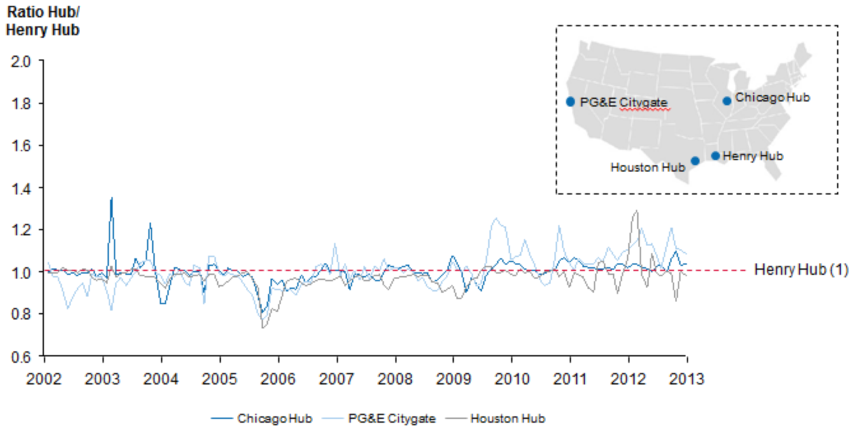


Figure 4.9: US Monthly Average Gas Spot Price Differentials (Henry Hub = 1, 2002-2012)

Source: Bloomberg, Booz & Company Analysis

A further illustration of how Henry Hub sets prices in all physically connected markets, is Cheyenne hub. Cheyenne was a relatively isolated and oversupplied regional gas market. It became physically connected to the Mid-Western US market when the Rockies Express Pipeline was built in 2007 (REX). From then on, gas from Cheyenne could flow to other (higher-priced and/or undersupplied) Midwestern markets. As a result of this physical connection, Cheyenne prices converged with Henry Hub prices (see Figure 4.10). Interestingly, in this specific case, prices rose for the newly connected market as a result of market integration. This can be explained by the fact that the Cheyenne market was oversupplied and connected with a less well supplied system.

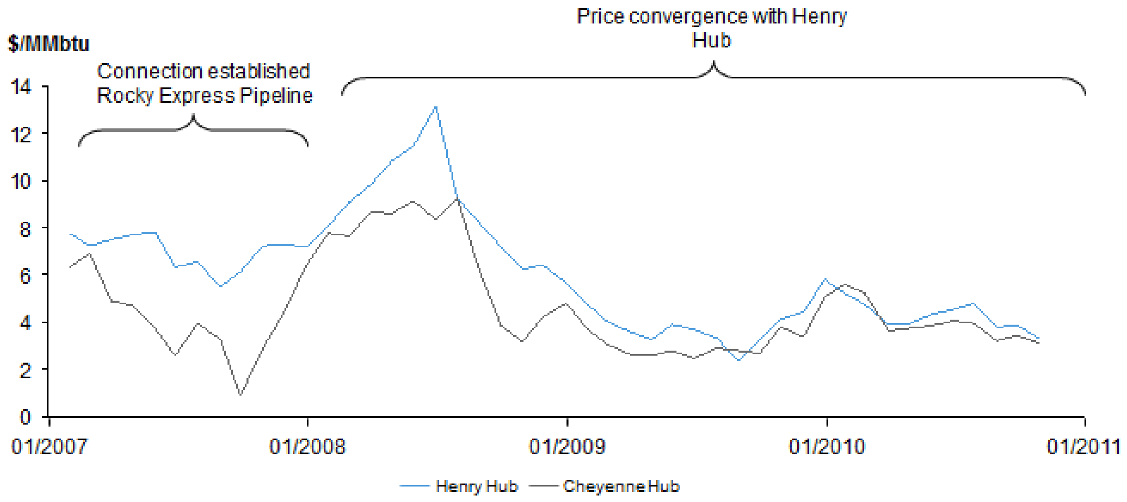


Figure 4.10: Monthly Average Gas Spot Prices at Cheyenne Hub and Henry Hub ($/MMbtu, 2007-2010)

Source: Bloomberg, Booz & Company Analysis

Sources: BP 2012, Eurostat, IEA, RBNEnergy, Sabine Pipe Line LLC, Texaco, FERC, Bloomberg

4.2.5 *Summary on benefits of gas market integration on price*

Benefits have been identified as annual benefits versus the Base Case, i.e. the state of European gas markets in 2012. The *maximum* annual gas price-related benefits of market integration, enabled by market liberalisation are ~€30bn in the "Full Integration" situation versus the Base Case (see Figure 4.11). This number is predicated on the current price differential between NW-European hub-prices and oil-indexed prices. If the European supply/demand balance changes, e.g. as a result of sudden demand growth in Europe or elsewhere in the world, or as a result of an unexpected supply reduction, hub prices will likely rise reducing the difference with oil-linked prices, and reducing the benefits of integration.

Europe already benefits from market integration, as evidenced by Scenario 1, and further benefits may be achieved as markets continue their integration toward "Full Integration" (Scenario 3). In addition to the benefits as described and quantified above, market integration may put further downward pressure on retail prices, as it can facilitate players competing in different national markets, thereby increasing the competitive pressure in those markets. We have not taken this effect into account for the purpose of this study, as in several Western European markets competition already exists at the resale/retail level of the value chain, and the additional competitive pressure generated by international market integration is likely to be relatively small compared to the changes in border prices. In East European markets, where currently retail markets exhibit less retail competition, an additional benefit may be generated by the onset of resale/retail competition. However, as the relevant volume to which this benefit applies is relatively small we have not taken it into account in this study.

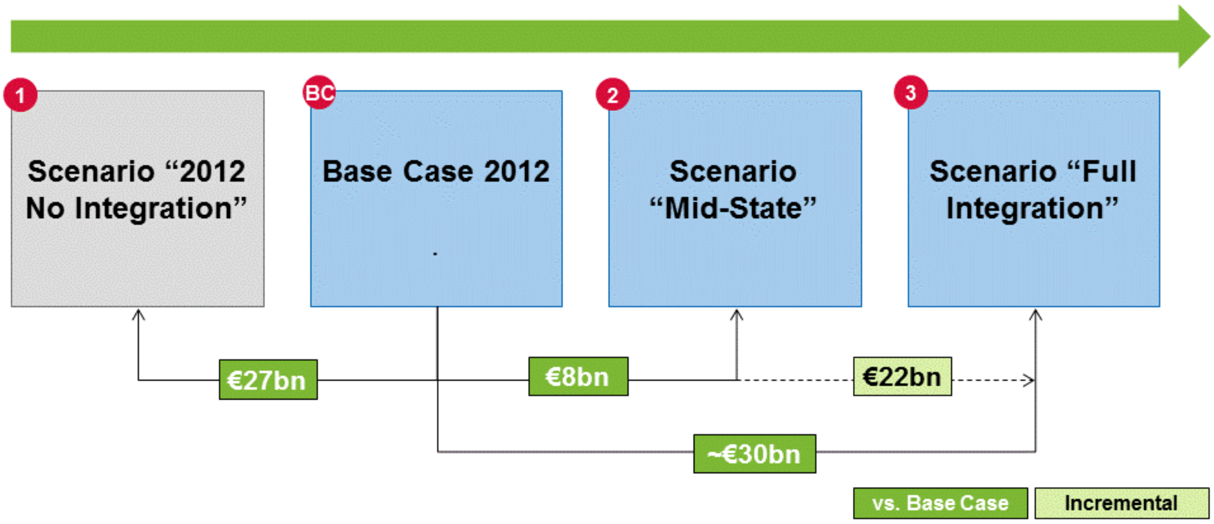


Figure 4.11: Summary Maximum Annual Benefits of Market Integration on Price

Note: Assumed market is oversupplied across the entire time period of analysis
Source: Booz & Company Analysis

4.3 INTEGRATION BENEFITS FOR SECURITY OF SUPPLY

4.3.1 *Benefits and Methodology*

Market integration is strongly dependent on the presence of connecting infrastructure to transport gas between markets. Therefore, in a situation with full market integration as in Scenario 3, infrastructure capacity is abundant and accessible to market players so as to allow gas trade and flows without infrastructure limitations. Sufficient connecting infrastructure is a *conditio sine qua non* for free gas flows and trade, but is not the only condition. Also the right regulatory and political conditions in the different member states need to be in place for this situation to arise.

Increasing connecting infrastructure capacity (or market players' access to it) increases security of supply: it enables countries (and regions) to diversify sources of supply, and reduces the risk of (economic) damage of supply interruptions from problems with existing supply infrastructure. On the other hand, an increase in connecting infrastructure capacity can result in higher coordination costs for pricing, scheduling and balancing protocols for infrastructure owners (see Literature Review). Therefore, appropriate market and industry structures, market designs, and regulatory institutions have to be in place to manage an increase in system complexity. For analysis purposes, we assume that the right market conditions are in place in the scenarios considered.

The result of increased security of gas supply is a reduction in the probability of occurrence of outages in the gas supply for a given country. An outage of gas supply can generate important damage to an economy: industrial facilities that use gas to produce heat for their production lines cannot operate; as gas-fired power plants cannot generate required electricity power plants with more expensive or more polluting fuels need to back-fill lost capacity or even brown-outs may occur, and small enterprises and offices cannot open for trade. A gas supply outage therefore will impact the GDP of a country. To quantify the benefits of increased security of supply we have calculated the reduction in "GDP at risk" from a 1% reduction in the probability that a EU27 country suffers a total gas supply interruption of one day in duration. Not every EU27 country's economy is equally dependent on gas, and therefore we have performed the calculation for each EU27 country separately. Note that we do not estimate the absolute probability of occurrence of a supply disruption, as this is impossible to do. The share of gas in total gross inland energy consumption of a country is taken as a proxy for the share of GDP that is exposed to gas supply, the "GDP at risk". In doing this, we assume that GDP is largely energy-dependent, and that the relative importance of gas in a country's energy mix is a good indicator for the contribution of gas to its GDP. The relevance of gas to an economy and GDP varies significantly across EU27 member states (see Figure 4.12).

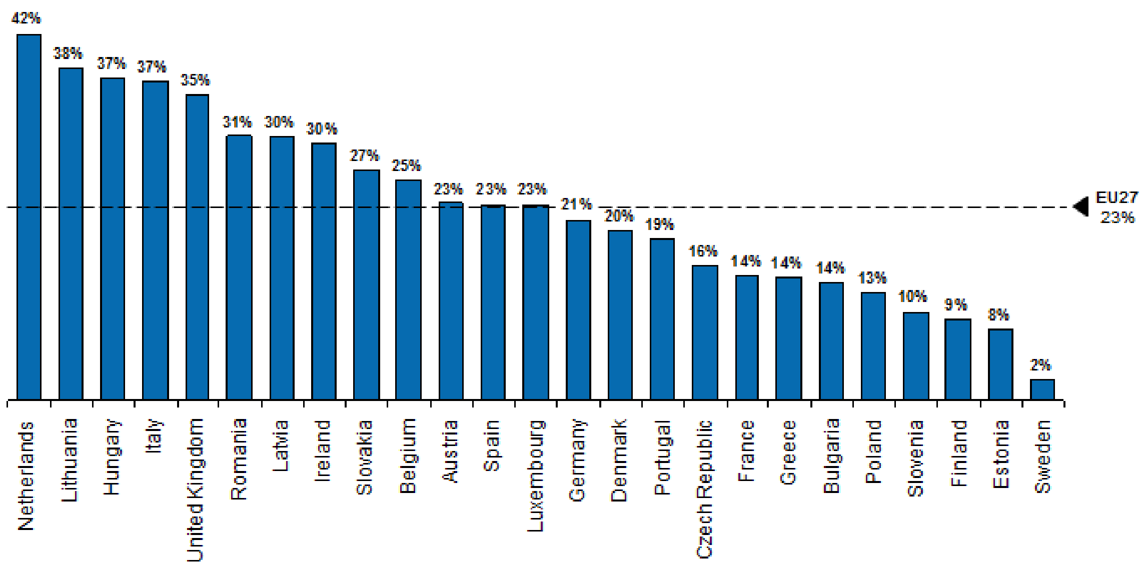


Figure 4.12: Share of Natural Gas in Gross Inland Energy Consumption (2011)

Note: Malta and Cyprus not shown as these countries did not have any gas consumption in 2011
Source: Eurostat, Booz & Company Analysis

We do not attempt to quantify the benefits for security of supply enjoyed today versus Scenario 1. It is difficult to determine which infrastructure that has been built in the past 12 years or so, would or would not have been built in a situation without European initiatives and pressure toward liberalisation and integration. Therefore, we focus this analysis on the two forward-looking scenarios: Scenario 2 "Mid-State", and Scenario 3 "Full Integration".

For Scenario 2 "Mid-State", we assume that an improvement in security of supply occurs for those countries benefiting from infrastructure additions that have not been built yet, but for which FID has been taken and that will be operational by the time "Mid-State" occurs, i.e. full implementation of the Third Package in all EU27 member states. For these countries we estimate the reduction in GDP at risk when a 1% reduction occurs in the probability of that member state suffering a total gas supply disruption of one day in duration (based on 2015 data).

For Scenario 3 "Full Integration", we assume that each EU27 member state enjoys "N-1" supply conditions, i.e. each country has sufficient additional supply capacity to satisfy peak demand for gas even if the largest supply infrastructure element is interrupted (see Figure

4.13). The cost associated with increasing security of supply is estimated by calculating the additions in infrastructure that would be necessary to establish "N-1" in each EU27[25] country. Subsequently, we estimate the reduction in GDP at risk when a 1% reduction occurs in the probability of a supply disruption for each EU27 country (based on 2030 data). (See Appendix A Figure 7.4 for more details on methodology).

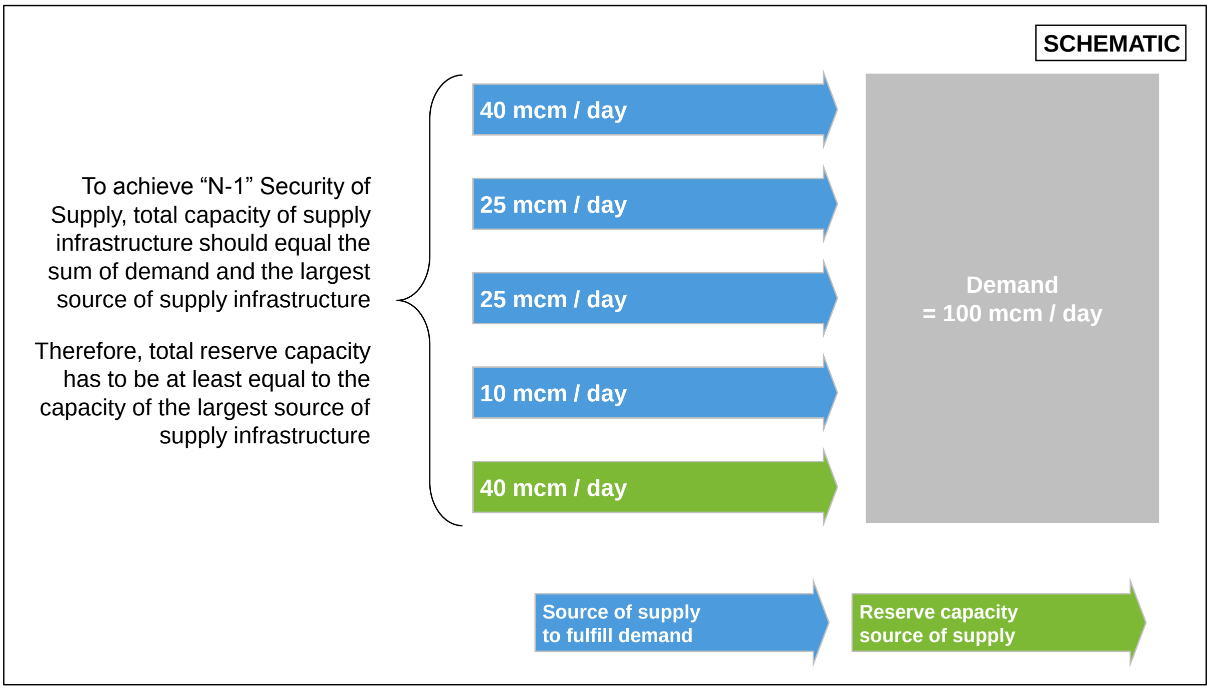


Figure 4.13: Concept of "N-1" Security of Supply

Source: Booz & Company

4.3.2 *Benefits Scenario 2 "Mid-State"*

Across Europe, a number of investments in gas infrastructure have been planned for which financial investment decisions (FID) have been taken. In total, 19 EU27 member states are impacted by these investments, and may as a result experience improved security of supply (see Table 4.3). For each of these 19 countries we have calculated the reduction in daily GDP at risk (in €mn, in 2005 Euros) of a 1% reduction in the probability of the occurrence of a supply disruption of one day in duration (see Figure 4.14).

Table 4.3: EU27 Physical Gas Supply Infrastructure Increase 2012-2015

Country	Pipeline Import Capacity[1)]	LNG Import Capacity[1)]	Storage Deliverability[1)]
Austria			
Belgium			
Bulgaria			

[25] *Due to no availability of infrastructure projections beyond 2022, we base our "N-1" analysis for the "Full Integration" Scenario on 2022 data from the ENTSO-G TYNDP 2013-2022*

Country	Pipeline Import Capacity[1]	LNG Import Capacity[1]	Storage Deliverability[1]
Czech Republic			
Cyprus			
Denmark			
Estonia			
Finland			
France			
Germany			
Greece			
Hungary			
Ireland			
Italy			
Latvia			
Lithuania			
Luxembourg[2]			
Malta			
Netherlands			
Poland			
Portugal			
Romania			
Slovakia			
Slovenia			
Spain			
Sweden			
United Kingdom			

Note: Green highlighted indicates a projected supply infrastructure increase
Indigenous production not included (production expected to decrease across EU27, or increase marginally only)
1) Additional capacity concerns capacity that is to be added between 2012 and 2015 and for which FID has been taken
2) In ENTSO-G 2011, an increase in pipeline capacity projected in 2015 from Belgium to Luxembourg; in ENTSO-G 2013 increase not reported (therefore assumed capacity is not to be increased)
Source: ENTSO-G TYNDP 2011-2020 and 2013-2022, Booz & Company Analysis

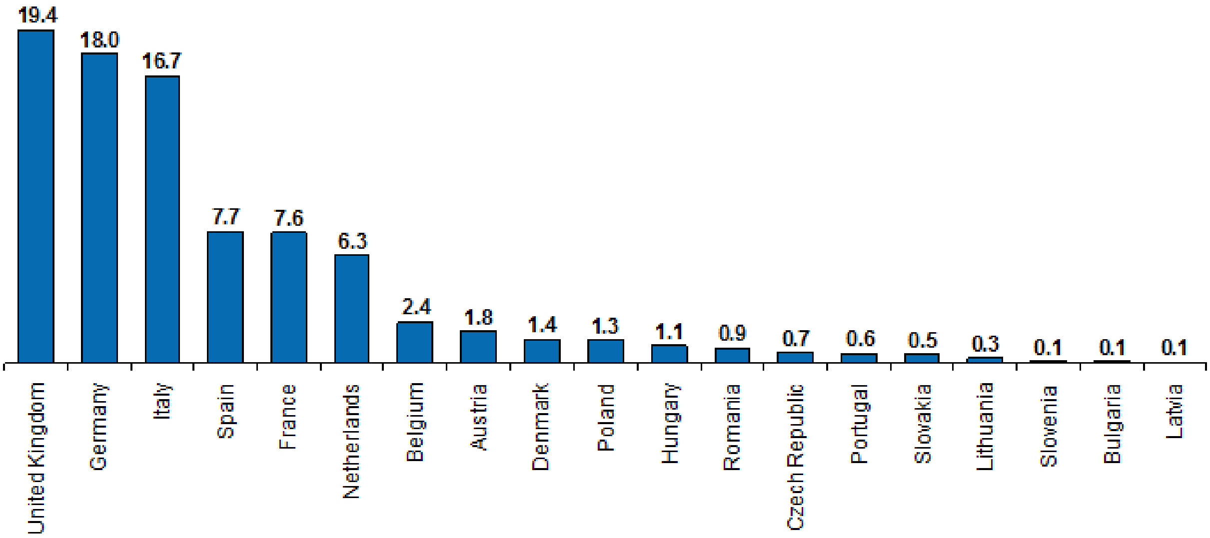


Figure 4.14: Reduction in daily GDP at Risk of a 1% Reduction in Probability of the Occurrence of a supply disruption of 1 Day Duration in Scenario 2 "Mid-State" (€mn in 2005 Euros)

Note: GDP is expressed in €mn in 2005 Euros as reported by PRIMES
Only countries shown impacted by infrastructure investments for which FID has been taken 2012-2015 (see Table)
Calculations based on PRIMES Scenario CPI 2015 data for GDP, Energy and Gas Gross Inland Consumption: ((GDP 2015 x % of gas in the energy mix 2015)/365) x 1%

Source: ENTSO-G TYNDP 2011-2020 and 2013-2022, PRIMES CPI Scenario 1990-2050, Booz & Company Analysis

Overall, the reduction in daily GDP at risk ranges between €0.1-19mn (in 2005 Euros). The NW-European countries have the highest *absolute* benefit. However, in *relative* terms as a percentage of total GDP, the impact is similar across some East European (e.g. Lithuania and Hungary) and West European markets (e.g. the Netherlands and Italy), as these countries have comparable levels of gas as a share of the total energy mix.

4.3.3 Benefits Scenario 3 "Full Integration"

In the "Full Integration" scenario, all EU27 countries are assumed to enjoy "N-1" security of supply. However, 10 countries will not reach "N-1" based on 2022 projections for infrastructure capacity[26] (see Figure 4.15). To achieve "N-1" in all EU27 member states, an estimated additional aggregated installed infrastructure capacity of ~100 mcm / day would be required across these 10 countries. Of course, the total size of the investments to realize this addition in connecting infrastructure capacity depends on the type of infrastructure to be built (pipeline capacity, LNG regasification terminals or storage facilities). Notwithstanding physical limitations, additional investments required may add up to an estimated €1.5-3bn.[27] These investments would be on top of the investments in projects for which FID have already been taken until 2022 across the EU27. ENTSO-G reports an aggregate cost estimate for these projects of ~€10bn, although this figure covers only 35% of

[26] *Based on infrastructure projects for which FID has been taken. Source: ENSTO-G TYNDP 2013-2022*

[27] *Based on a proxy of €15-30mn investment per mcm / day installed capacity. This proxy is based on historic and planned investment projects for pipeline infrastructure, LNG regasification and UGS facilities*

all projects for which FID is taken.[28] Therefore, the cost estimate for infrastructure projects with FID until 2022 is more than €10bn. We do not advocate that the additional investment of €1.5-3bn to achieve "N-1" security of supply across all EU27 states is necessary to achieve market integration. Nor are we passing judgment on the financial viability and attractiveness of such investments, or which parties should finance such new infrastructure.

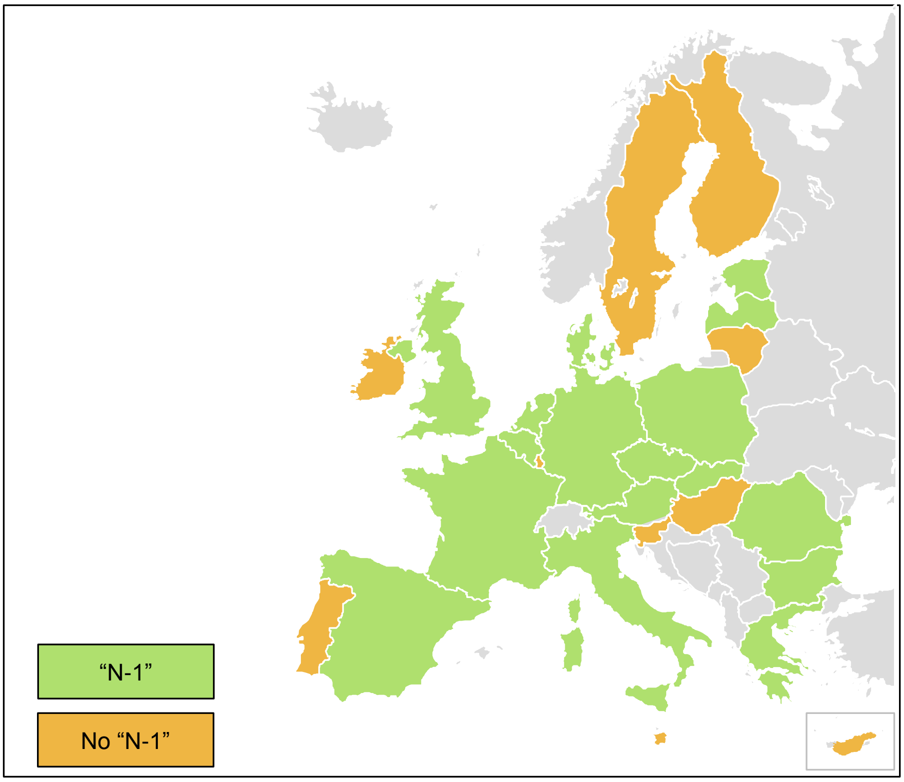


Figure 4.15: "N-1" in EU27 in Scenario 3 "Full Integration" (based on 2022 ENTSO-G data)

Note: Demand based on ENTSO-G 2022 high daily demand; daily capacity infrastructure based on projections 2022 for all projects for which FID is taken (daily pipeline capacity, maximum send-out capacity LNG terminals, and maximum send-out capacity Underground Gas Storage (UGS)); Production based on PRIMES CPI Scenario 2030
ENTSO-G reports UGS facilities at aggregated level; where aggregate storage volumes distorted outcome of "N-1" analysis, ENTSO-G storage capacities split based on available information at individual storage facility level

Source: ENTSO-G TYNDP 2011-2020 and 2013-2022, PRIMES CPI Scenario 1990-2050, GSE Storage Database May 2012, Booz & Company Analysis

Overall, the value of a 1% reduction in the probability of occurrence of a major gas supply disruption in terms of daily GDP ranges between €0.04-24mn (in 2005 Euros, see Figure 4.16). NW-European countries would, similar to in the "Mid-State" scenario, benefit most in *absolute* GDP from a reduction in the probability of a supply disruption occurrence. This may be expected, as these countries have amongst the highest absolute GDP, and have economies that continue to be relatively dependent on gas. However, in *relative* terms as a percentage of total GDP, the impact is similar across some East European (e.g. Hungary and Lithuania) and West European markets (e.g. Belgium, UK, and Germany).

[28] *Cost estimated for the other 65% not disclosed to ENTSO-G, and therefore not included. ENTSO-G specifically states that the estimate cannot be extrapolated to calculate the total cost estimate for all projects. Source: ENTSO-G TYNDP 2013-2022 Main report*

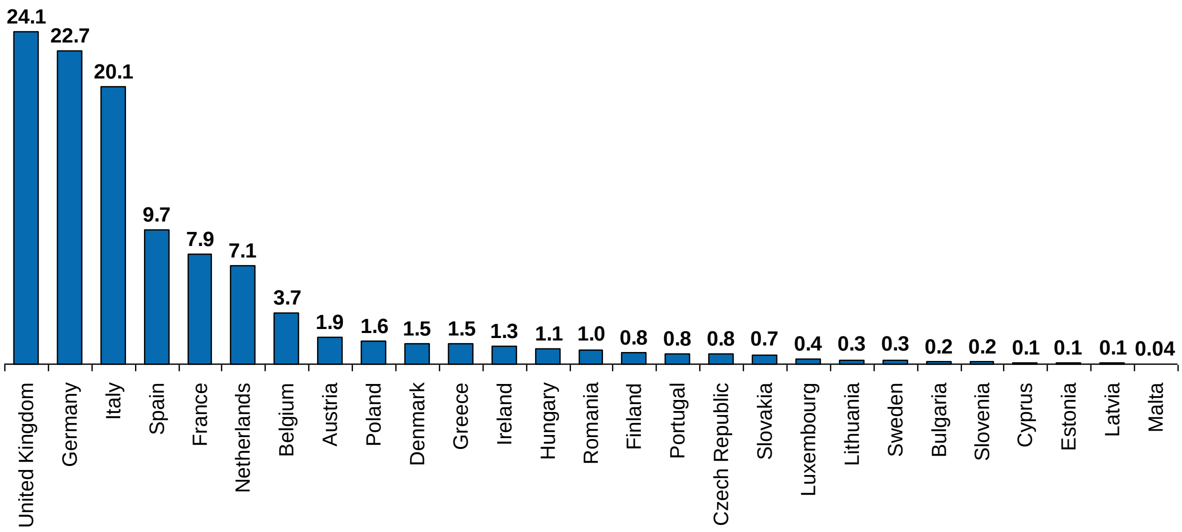


Figure 4.16: Reduction in daily GDP at Risk of a 1% Reduction in Probability of the Occurrence of a supply disruption of 1 Day Duration in Scenario 3 "Full Integration" (€mn in 2005 Euros)

Note: GDP is expressed in €mn in 2005 Euros as reported by PRIMES
Calculations based on PRIMES Scenario CPI 2030 data for GDP, Energy and Gas Gross Inland Consumption: ((GDP 2030 x % of gas in the energy mix 2030)/365) x 1%

Source: ENTSO-G TYNDP 2013-2022, PRIMES CPI Scenario 1990-2050, Booz & Company Analysis

Case Study G2: Iberian Peninsula and Security of Supply

The total Iberian Peninsula had a gas consumption of ~39 bcm in 2012, of which Spain's share amounted to ~85%. Both Spanish and Portuguese gas demand have experienced significant change over the past decade. From 2003 to 2008, gas demand in Spain grew with ~10% per year. This reversed after 2008, and turned into a decline of ~5% per year. Both the growth and the decline were driven primarily by gas demand in power generation. In Portugal, consumption has grown at an average of ~5% since 2003. This case study will focus on the Spanish market.

Spain is connected to foreign gas suppliers through pipelines from France, Morocco and Algeria, and via 7 LNG regasification terminals (see Figure 4.17). Spanish import capacity has grown significantly in the past decade: from ~51 bcm / year in 2005 to ~86 bcm in 2011 (average growth of 9% per year). The expansion in import capacity in combination with declining demand has resulted in reduced utilization of import infrastructure. In combination with a flat to continued declining gas demand forecast after 2015, Spain's security of supply is not necessarily at risk due to insufficient physical infrastructure. The risk for the Spanish market lies more in the fact that the country's supply is relatively undiversified, with more than 50% of its gas supply dependent (2011) on Nigeria and Algeria (see Figure 4.18). Uncertainties in Nigerian investment policies and regulatory frameworks make the country less attractive for investments in new infrastructure and upgrades of existing facilities. This has delayed plans for new LNG terminals, and caused a delay in the expansion of the only natural gas liquefaction facility in Nigeria. Moreover, gas production and transport infrastructure have had to declare *force majeure* in the recent past. For example, an LNG spot cargo tender was cancelled in March 2013 because the producer could not supply gas to the Nigerian liquefaction terminal due to pipeline sabotage.

Likewise, Algeria experienced an attack on the gas facility Tiguentourine in In Amenas in January 2013, leading to a disruption in production at the site for several weeks, illustrating the vulnerability of gas production facilities and supply in the country. Moreover, Algeria's gas sector is dominated by one party, Sonatrach. Spain's gas supply is therefore for more than one third dependent on the relationship with this party.

Expanding Spain's connection with the French and NW-European supply system through increased cross-border pipeline capacity with France would help to diversify Spain's supply base and reduce its high dependency on just two countries for gas supply. Such infrastructure is also necessary to integrate Spain's gas markets more with the other West European gas markets. Indeed, plans exist for a further expansion of the existing gas pipeline that connects Spain with France.

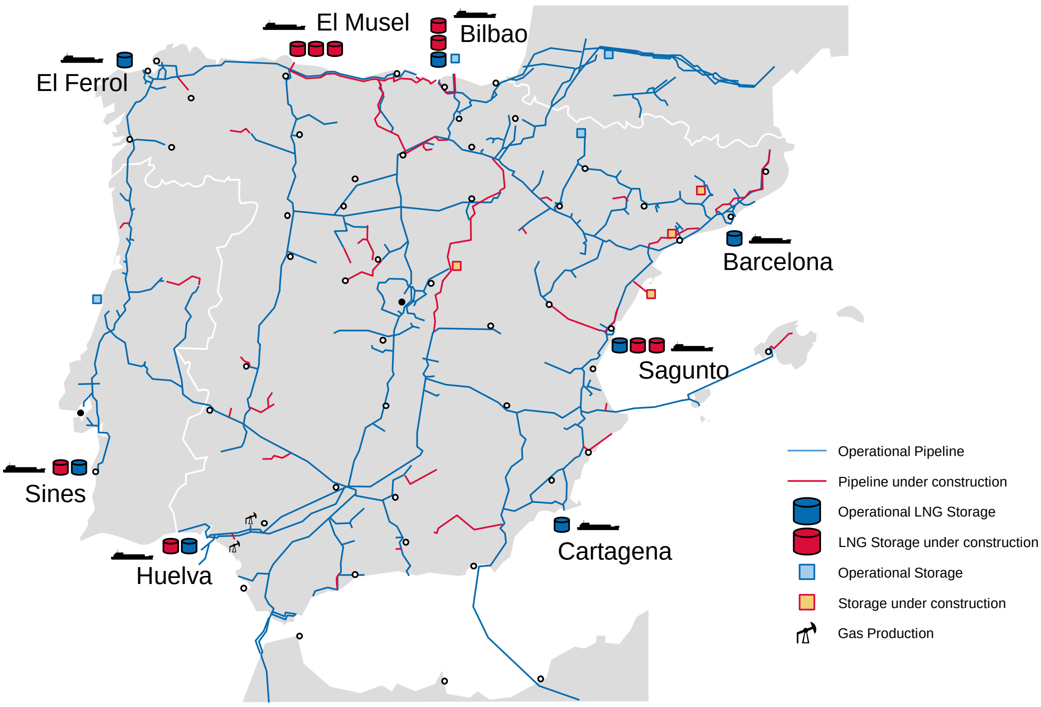


Figure 4.17: Spanish & Portuguese Natural Gas Infrastructure (2012)

Source: Sedigas, Booz & Company Analysis

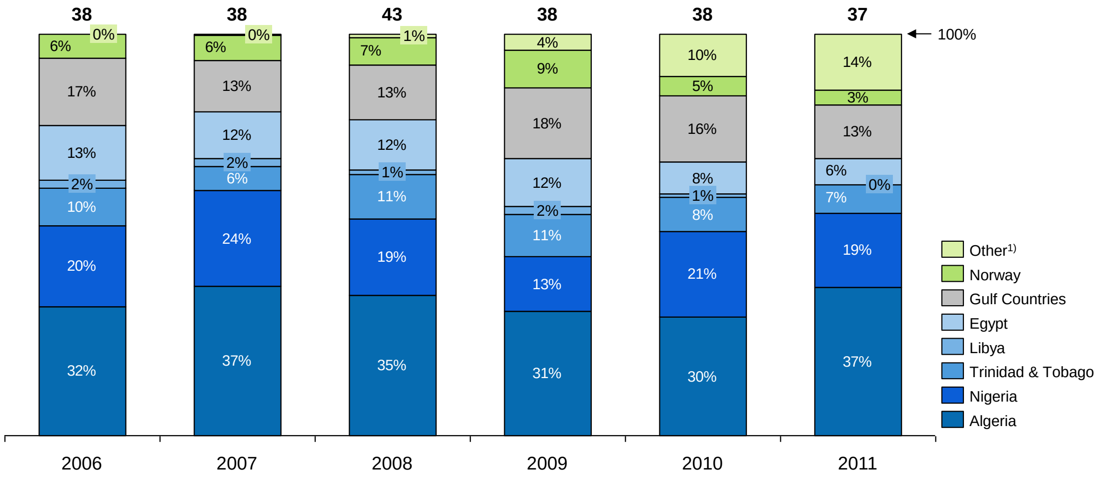


Figure 4.18: Spanish Gas Imports by Supply Country (bcm, 2006-2011)

1) Includes amongst others Belgium, France, Italy, Peru, Yemen, Portugal, United States of America

Source: Sedigas Annual Report 2011, Booz & Company Analysis

Sources: Eurostat, Sedigas, Spanish Energy Regulator's Annual Energy Report to EU Commission, EIA Country Analysis Briefs Nigeria (2013) and Algeria (2012), The Guardian (Nigeria), The Tide (Nigeria), Statoil Website 2013

Case Study G3: North-Western Europe and Security of Supply

Each NW-European gas market now has a physical or virtual trading hub, in different states of maturity and liquidity (see Figure 4.1). While the gas markets in these countries are not formally integrated, with each having its own TSO(s), regulation and grid codes, we do observe that the prices that are established on the hubs have converged (see Figure 4.5). Connecting infrastructure allows for players to trade and ship gas across borders, albeit within the constraints of available cross-border capacity.

The existence of liquid hubs contributes to the security of supply of NW-European markets. The price established at a hub is a reflection of the supply / demand situation in a market at any given time. In periods of supply shortage the resulting higher hub prices will attract supply. Conversely, in a period of oversupply the resulting lower price will make the market less attractive and supply will reduce (see also Makholm, 2007 in chapter 2, literature survey). This phenomenon is already visible on NW-European hubs, where price spikes occur when supply scarcity is expected (see Figure 4.19).

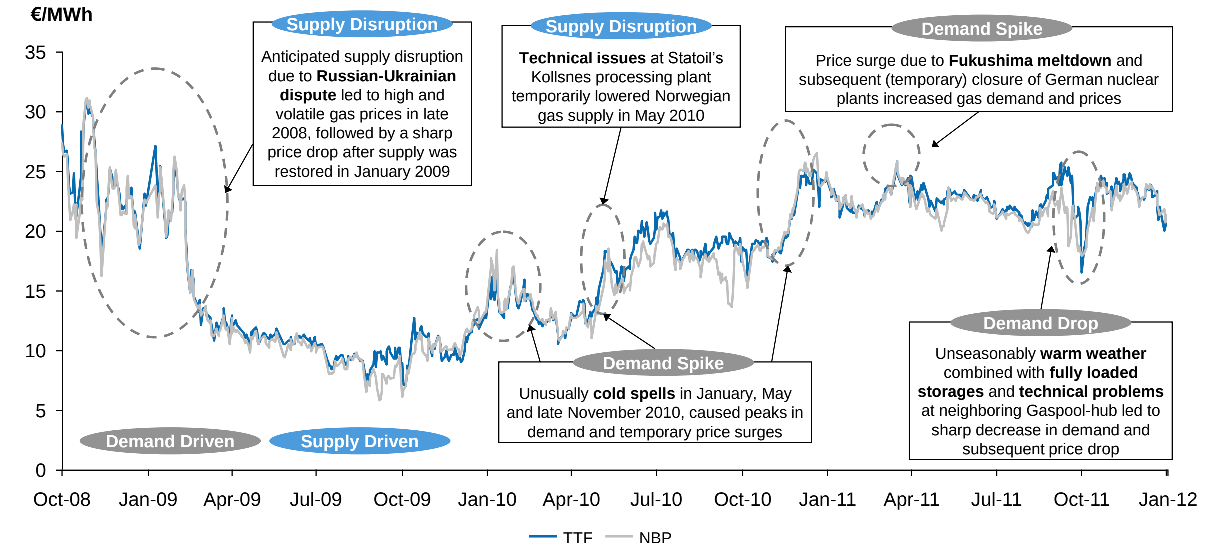


Figure 4.19: Supply / Demand Mechanism at NBP and TTF (Day-Ahead Price € / MWh, October 2008 – December 2011)

Source: Bloomberg, European Spot Gas Market, Dutch Metrological Institute, CNN, Makholm 2007, Booz & Company Analysis

4.3.4 *Summary on benefits of gas market integration for security of supply*

Additional physical interconnectivity enabling market integration can increase the diversification of supply, and reduce the dependency of markets on a limited number of sources of supply. It thus reduces the risk of occurrence and impact of a potential major supply disruption. We estimated the reduction in GDP at risk of a 1% reduction in the probability of occurrence of a major gas supply disruption of one day in duration, given the relative importance of gas to each EU27 market. This value in absolute terms is the highest in NW-European markets, in both the "Mid-State" and "Full Integration" scenario, as the energy mix (and thus the economies) of NW-European countries are generally more dependent on gas than that of Southern and Eastern European countries, and generally have higher absolute GDP. Thus, these markets enjoy the highest *absolute* benefit from an improvement in security of supply. However, *relative* benefits in terms of percentage of GDP are largely driven by the importance of gas to an economy, which varies across EU27 member states.

In addition to the €10bn+ of grid investment required in the Full Integration scenario, further infrastructural investments of €1.5 billion to €3 billion would be required to achieve "N-1" security of supply for all EU27 member states (based on 2022 gas demand data), depending on which type of infrastructure is chosen: connecting pipelines, storage facilities, or LNG regasification capacity. It should be noted that this analysis excludes potential additional connecting infrastructure that may be needed *within* countries, should bottlenecks exist within the transportation grids of those countries. Also, we do not claim that this investment is necessary to achieve market integration, nor have we analysed the financial viability and attractiveness of such investments, or which parties should finance such new infrastructure. In addition, further circumstances may be required to achieve market integration over and beyond sufficient (accessible) connecting infrastructure, such as the right market design, and other enabling regulatory and legislative measures.

4.4 CONCLUSIONS ON INTEGRATION OF GAS MARKETS

Market integration can produce important economic benefits from price effects and from increased security of supply. If the current situation of oversupply continues, market integration could facilitate a maximum benefit from price effects of up to €30 billion per year for EU27. In addition, we have demonstrated that several of the EU27 countries are already enjoying benefit facilitated by market integration. As further markets within the EU mature in terms of market liberalisation and integration, more member states will be able to experience similar benefits. Whilst our analysis has concentrated on import and wholesale prices, market integration can also lead to more players entering end-user markets and thus increasing competition within national markets. This may generate additional price pressure in retail markets and thus additional economic benefits.

For market integration to occur, sufficient available connecting infrastructure between markets is necessary, in combination with the supporting regulatory and political conditions to foster trade. Further connecting infrastructure reduces the dependency of markets on a limited number of sources of supply, and can therefore improve a market's security of supply. The impact of such an improvement in security of supply can be measured in terms of a reduction of GDP at risk caused by a significant supply outage. This differs significantly across countries, and is dependent on a market's dependence on gas and the absolute levels of GDP. A probabilistic estimate from country to country of the GDP at risk of a 1% reduction in the probability of occurrence of a major gas supply disruption for that country ranges from ~€0. 1 million to €19 million (in 2005 Euros) in the "Mid-State", and ~€0.04 million to €24 million (in 2005 Euros) in our "Full Integration" scenarios.

To achieve the "N-1" security of supply across all EU27 member states assumed in our "Full Integration" scenario, an estimated investment of €1.5-3bn in supply infrastructure is required, on top of the €10bn+ investments up to 2022 reported by ENSTO-G for which a financial investment decision has been taken. We have not determined whether these extra investments are in fact necessary to achieve market integration, nor have we analysed the financial attractiveness of, or which parties should finance such investments.

5. ELECTRICITY MARKETS – FINDINGS

5.1 INTRODUCTION

The liberalisation and integration of the electricity market of the EU has proceeded in three stages. The first stage, which covers the period prior to the focus of attention of this study, ran up until about 2004. At this period there was a phase of liberalising energy markets, mainly in a national context. Our case study of the electricity market in England and Wales, which was the most thoroughly liberalised, indicates that the potential benefits of moving from monopolistic markets to a liberalised national electricity market with reasonably effective local competition in electricity supply and generation, can be of the order of about 10% of the cost of supply. Other countries have chosen to comply with EU requirements without necessarily providing for structural reforms to the market that would provide reasonably effective local competition in supply and generation, and will likely have benefited rather less. These are matters of national competence, and distributional concerns may outweigh efficiency concerns in some countries. Although we describe this period as ending in 2004, in practice countries may still choose to reform their local market structure to increase levels of effective competition after this date. The creation of the Single Electricity Market combining the Republic of Ireland and Northern Ireland is perhaps the most dramatic example, but MIBEL integrating Spain and Portugal, is another post-2004 example.

The second stage of electricity market reform covers the period during which market coupling is introduced to facilitate increased cross-border electricity trading. Market coupling has already been introduced to a number of regions or borders in the EU. It is expected to become a requirement to introduce it across the EU, or at least to have in place mechanisms to facilitate its introduction, by 2014, although in practice there may be some delay. The requirements of this study ask us to assess the effects of market integration measures in the EU from around 2004 to the present day, and from the present day to 2014. We have agreed an interpretation that 2004 to the present day should refer to the roll-out of market coupling to date; and that present day to 2014 should be interpreted as meaning the completion of the roll-out of market coupling. To that end we have assessed the impact of market coupling on a number of cross-border markets, to the extent we were able to obtain suitable data to do so. We have projected from the size of those results to the size of the presently coupled market, and to the likely future coupled market. In the following section of this report we report on that work and those results.

The third stage of electricity market reform is what might follow beyond 2014 if the EU were to take further steps towards electricity market integration. To that end we attempt to model the effect of different outcomes in the electricity market. Unlike our analysis of the market coupling era, we do not focus on specific market integration measures, rather we consider a more physical interpretation of counterfactual and integrated market, using our judgment to describe the physical characteristics of the market outcome in a market that continues to use the 2014 electricity market institutions, as compared with a fully integrated electricity market, Our electricity model permits us to assess the costs of operating the specified electricity system, defined by its generation location and mix and demand.[29]

[29] *Principal cost assumptions are shown in Appendix C.*

The model includes a calculation of the optimal quantities of transmission capacity to build to facilitate that integrated market. We can therefore assess the costs of operating the market as a fully integrated market, where the optimal transmission would be available. This then is the potential situation that we can reach if the market is fully integrated, where the European electricity market would operate as if there were no restrictions imposed by national boundaries, and is perfectly despatched. To assess the costs of the alternative system that would arise if the 2014 market institutions are perpetuated, rather than achieving perfect integration, we need to apply our judgment to describe physical scenarios that would arise in that alternative world. The model can be used to assess how much additional generation must be built if there are constraints on transmission, or the costs of operating with a different specification of generation mix. We therefore construct "policy scenarios" (as opposed to the underlying market scenarios known as CPI and RES) that represent the consequence of different levels of integration in the market.

As we noted in Section 3.3.2, there may be some concern that our Baseline scenario assumes that the optimal quantity of transmission capacity is constructed, and there may be difficulty in achieving that. We have considered a variation to the 2030 Baseline case where only half of the optimal transmission capacity (half of the increment from today's level) is built. (This is similar to the Integrated with Low TX scenario we consider.) This has a reduction in economic benefit relative to the Baseline scenario of €2.6bn per year. This is relatively modest amount in comparison to the benefits of integration mentioned below indicates the robustness of our results.

5.2 The Benefits of Integration in The Market Coupling Era 2004-2014

5.2.1 *Introduction: The Era of Market Coupling*

The main institutional change that has occurred in the era 2004 to 2014 has been the gradual introduction of market coupling across European markets, which has recently accelerated. According to the Target Model it should be fully introduced across Europe by 2014 (with some minor derogations), but in reality is likely to be somewhat delayed, and further refinements in its mode of operation are likely to continue to arrive later. A complete treatment of market coupling, our methodology and data analysis, is reported in Appendix B. Here we briefly report on our findings from the study reported there.

Market coupling ensures that interconnectors are more efficiently used by simultaneously clearing their capacity with all bids and offers into the day-ahead auction. Before interconnectors were coupled, traders had first to secure capacity ahead of time on the interconnector, based on a prediction of likely price differences across the interconnector, and then offer or bid into the power exchanges on each end of the interconnector. In addition to daily auctions, most interconnectors also ran month, quarter and/or year ahead auctions for capacity, which could be nominated the day-ahead, if valuable, or withheld if not. The result of these various contracts ahead of time depended upon the rules of operating the interconnector, the liquidity of the various markets (for contracts and in the power exchanges) and the predictability of the price differences across the interconnector (and hence the direction of flows). In practice, there is some considerable unpredictability, which meant that trades were often ex post inefficient – there would be underused capacity when a substantial price difference remained, or trade was even against the price difference, described as a Flow Against Price Differential, or FAPD.

One measure of the inefficiency of interconnector use before coupling comes from the comparing the price differences and the flows. Figure 5.1 illustrates this for flows between the Netherlands (APX) and France (PowerNext) (Moss, 2009), showing that much of the time the interconnector was underutilised, and for a considerable fraction of the time the power flowed in the wrong direction. After market coupling the price differences between the two countries dramatically narrowed, as shown in Figure 5.2. Before market coupling the prices were within €1/MWh only 10% of the time and were more than €10/MWh apart 39% of the time, but after coupling the prices were within €1/MWh 72% of the time and were more than €10/MWh apart only 14% of the time.

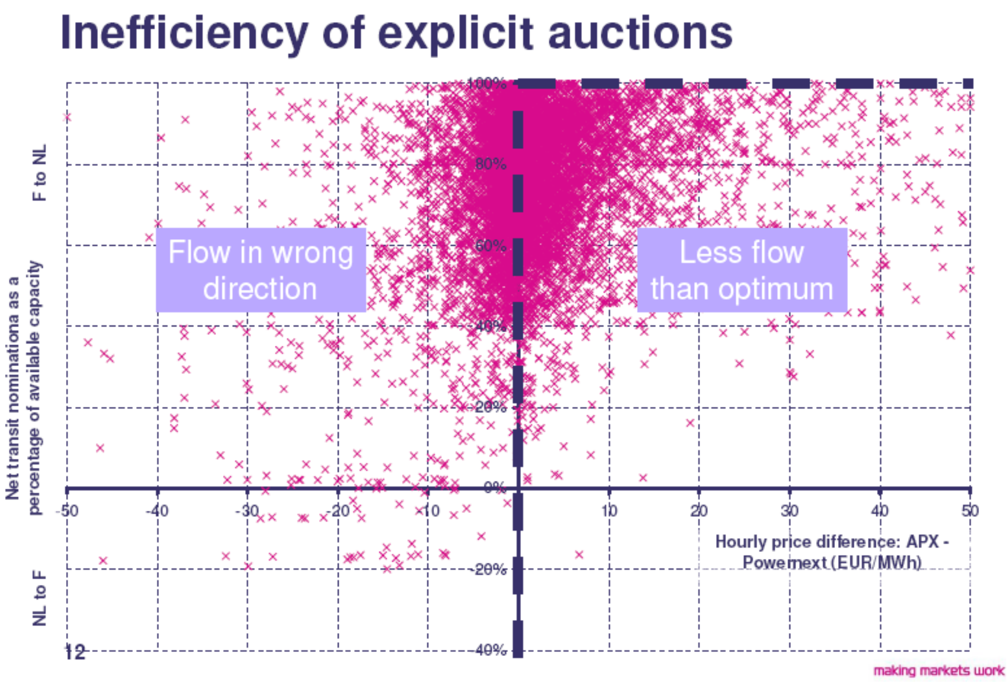


Figure 5.1 Price differences and utilisation of the NL-FR interconnector
Source: Moss (2009)

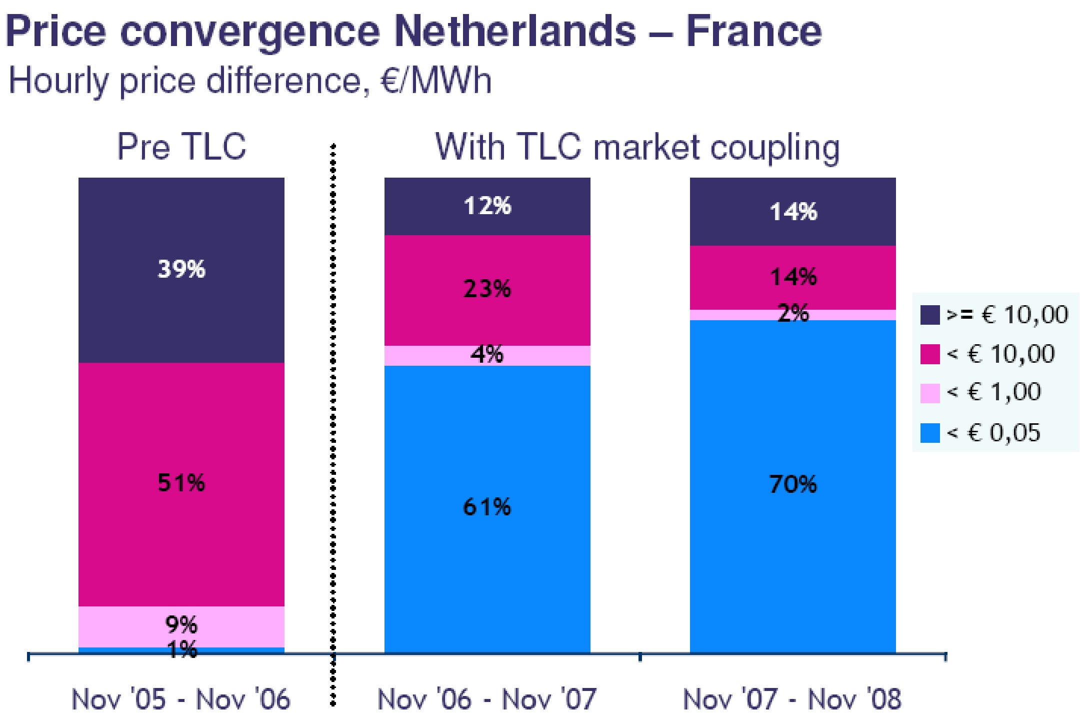


Figure 5.2: Extent of price convergence before and after coupling, NL-FR
Source: Moss (2009)

5.2.2 *The case of UK-France and France-Germany*

We have attempted to assess the effect of market coupling to assess the value of this improvement in the efficiency of trade across interconnectors, for some where we have data. We will then seek to extrapolate this to the market as a whole.

The volumes actually used and the price differences at which trade clears are observable for both coupled and uncoupled interconnectors, but unfortunately not the counterfactual of what they would have been had the interconnectors been respectively uncoupled or coupled. Given that there are no sufficiently accurate models that predict market prices (as opposed to, e.g. estimated marginal costs with optimal dispatch in idealised models), some way is needed to construct the counterfactuals. Ideally we would have an estimate of the slopes of net supply and demand in €/MW capacity. If we had no information and if the flows over the interconnectors were small compared to the total market into which they supplied, then a rough assumption would be to assume that prices did not change. An alternative is to consider the shape of realistic price curves and load duration curves, and from that we have assessed that the price is likely to change by no more than about 1€/MWh per GW change in load in most cases. This gives an alternative view. In the Appendix we show how we use these assumptions to calculate triangular amounts (half price times volume) to correct the approximate estimates of the gains from trade.

We have used these basic observations to study the trade on the UK-France interconnector (UK-FR) and the France-Germany (DE-FR) interconnector, as providing the best evidence on the effect of market coupling on trade.

Case Study E3: Interconnexion France-Angleterre, the France-UK interconnector

Interconnexion France-Angleterre (IFA)[30] is a high voltage DC link interconnecting the English and French transmission systems. The interconnector has a capacity of 2,000MW and supports transmission of electricity in both directions. It has been operational since 1986, allowing cross-border trade of electricity. It is jointly operated by National Grid Interconnectors Limited (NGIL) and Réseau de Transport d'Electricité (RTE). Historically, the flow has been mostly, but not entirely, from France to England. For example, in 2006, 97.5% of transfers were made from France to England, accounting for about 5% of total electricity available in the UK. The interconnector comprises of four 500 MW lines, which can be separately closed for maintenance or outage. Link availability is deemed satisfactory, being consistently above 93% for the past 5 years.[31]

The UK-FR interconnector is not directly coupled, but is indirectly coupled as a result of the explicit UK-NL coupling across the BritNed UK-NL interconnector, and the explicit coupling of the NL-BE-FR-DE market. This indirect coupling started during 2011 with the opening of the BritNed link and its associated market.

In the case of the IFA we observe:

- In 2011 exports from FR=>UK used 58% of total capacity and from UK=>FR a further 12%, making the overall utilisation of IFA 71%.
- In 2012 exports from FR=>UK used 74% of total capacity and from UK=>FR a further 10%, making the overall utilisation of IFA 83%.
- The average NTC in both 2011 and 2012 was roughly 1.25 GW in each direction (i.e. only 63% of its rated capacity), so an underutilisation of 29% in 2011 would be on average is 0.36 GW and the predicted price change (from the price duration curve) might be €0.36/MWh on average over the underutilisation, half that is €0.18/MWh.
- The extent of underutilisation was 14 TWh so the overstatement is €2.5 million, reducing the total 2011 losses from €23.6 million to €21.1 million or by 10%.
- In 2012 the underutilisation was 12.7 TWh so the overstatement was €2.3 million, reducing the total 2012 losses from €75.1 million to €72.8 million or by only 3%, proportionately rather less significant

Nevertheless it can be seen that inefficiencies remain material in this indirectly or partially coupled market.

For FR-DE we used a more eclectic set of sources and trace the trade by a mixture of estimation during the quarters of 2010, and make the following estimates.

[30] *National Grid, 2009,"IFA User Guide and Capacity Management System FAQ"*
[31] *National Grid,2010, "Interconnexion France-Angleterre Performance Report 2009-2010"*

Table 5.1: Estimated losses and trade DE-FR, Q1 2010-Q3, and actuals for Q4 2010 €*Millions*

Quarters	loss FR not exporting enough	Loss DE not exporting enough	FAPD FR	FAPD DE	total loss	actual trade	Potential trade
Q1 2010	€ 1.60	€ 2.59	€ 0.53	€ 0.88	€ 5.61	€ 43.88	€ 48.08
Q2 2010	€ 2.08	€ 4.97	€ 2.18	€ 0.97	€ 10.19	€ 14.85	€ 21.89
Q3 2010	€ 1.47	€ 4.41	€ 2.68	€ 0.46	€ 9.02	€ 20.02	€ 25.90
Q4 2010	€ 1.68	€ 3.34	€ 0.16	€ 0.66	€ 5.84	€ 36.87	€ 41.89
Year	€ 6.82	€ 15.31	€ 5.55	€ 2.97	€ 30.65	€ 115.62	€ 137.75

The Flow Against Price Differential (FAPD) certainly drops dramatically with coupling in Q4, although not to zero as coupling came half way through that quarter. We can also compare these estimates with another source we report in the appendix, according to which FAPDs for DE-FR accounted for just over €1 million in Q4 2010, and actual trade was €44 million. The figures in the table above for FAPDs for Q3 and Q4 in total are comparable to this, although the measured trade in Q4 at €37 million is somewhat below the actual €44 million trade. Total losses for the year are 22% of potential trade or 26% of measured trade, and this falls to 16% in Q4. For the first 3 quarters the losses are 31% of measured trade or 26% of potential trade. We assume no resistive losses over the interconnectors as they are part of the meshed grid, and the borders are infinitely thin.

5.2.3 *Overall assessment*

To review the patchy evidence presented above, with the exception of IFA for 2012, the losses from a failure to couple are probably higher than one quarter of measured trade. If that result holds more generally then one can gain a rough estimate of the EU-wide losses. Exports (and imports) in 2011 were about 315 TWh[32] out of 3,080 TWh supplied (or about 10%) so at the reference price is €50/MWh the total value of trade is about €16 billion/yr., and a quarter of that would be 2.5% of the total wholesale value of electricity traded, or €4 billion/yr. This could be an overestimate in relation to the Nordic market, as that has always been moderately efficiently interconnected. This total also includes the central European members who are unlikely to all couple by 2014. This then is the estimate of the potential value of market coupling from 2004 to 2014.

Figure 5.3 shows the extent of market coupling in 2011. It shows that a high proportion of the markets in Europe, by total population, are coupled to some degree or other. But the couplings are by sub-region, some quite small, such as Italy and Slovenia, some more extensive such as northwest Europe. Data on electricity trade by border might indicate how to divide this between present and potential gain. It seems likely that about half to two-thirds of the potential gain has been obtained by 2011.

[32] http://epp.eurostat.ec.europa.eu/statistics_explained/index.php?title=File:Electricity_Statistics,_2011_%28in_GWh%29.png&filetimestamp=20121128151011

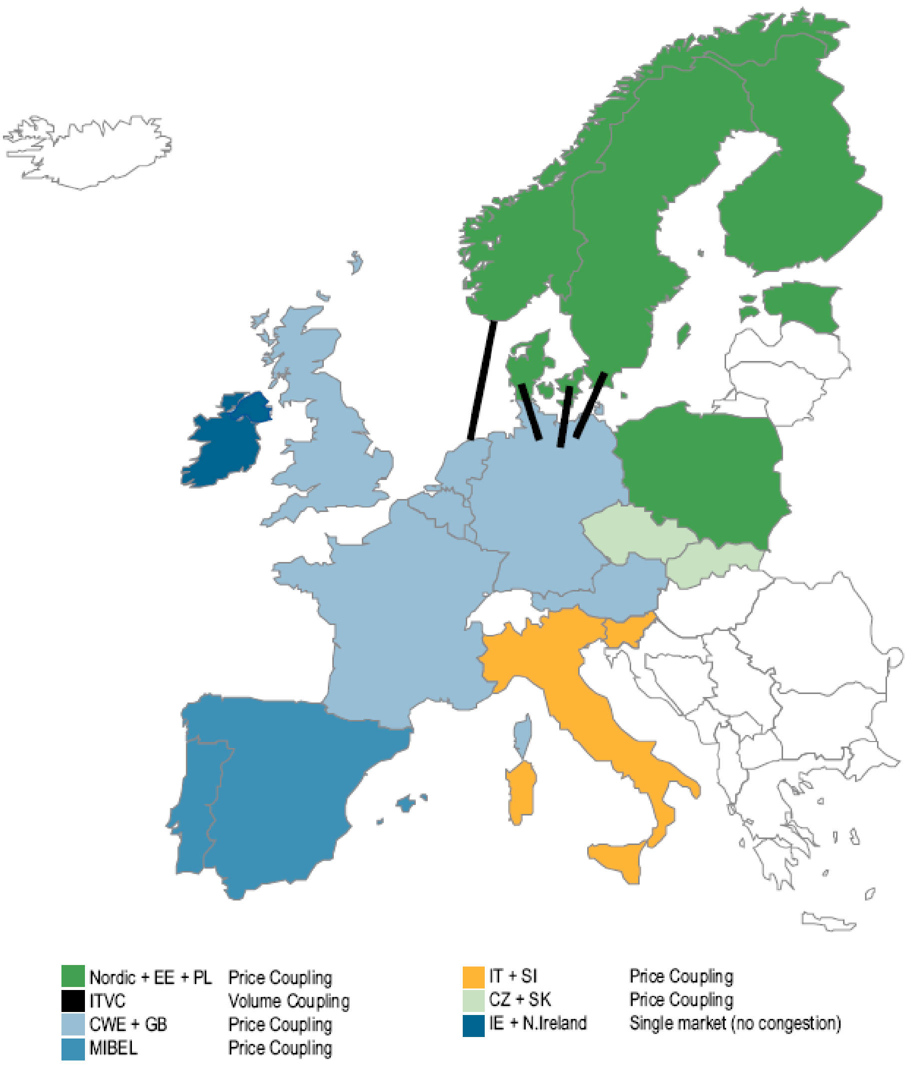


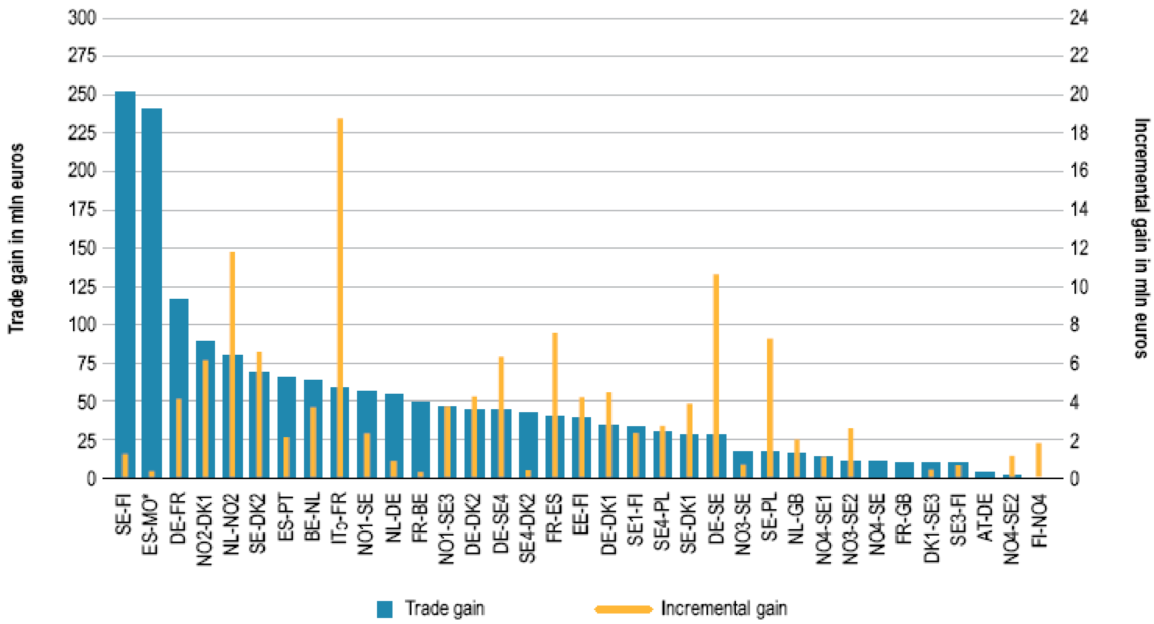
Figure 5.3: Market coupling in Europe 2011
Source: ACER (2012, figure 16).

ACER (2012) gives an interesting simulation study of the gross welfare benefits of cross-border trade, shown in Figure 5.4 below. We note the following extracts from the report.

> "Figure [5.4 below] shows the welfare gain from trade (that is "Welfare Trade Gain") by border for 2011, in millions of euros. This is the difference between the simulated gross welfare benefit stemming from the Zero scenario and the Historical scenario.[33] The figure also shows the so-called "Incremental Gain", which is the difference between the gross welfare benefit from the Historical scenario and that from the Incremental scenario, which assumes on a selected border an increment of 100MW extra interconnector capacity for trade. Note that extra capacity in this context need

[33] *The simulations were executed accordingly. Firstly, a complete batch with historical data for 2011 was created, including all order books, ATC values, etc. Based on this, the algorithm calculated the results of the Historical scenario. Secondly, the Zero scenario was calculated by altering the ATC value in the historical batch data to zero for one specific interconnector. Then the algorithm ran the calculations for the full year. This was repeated for each interconnector separately. The Incremental scenario was calculated in the same way, although increasing the ATC value in the historical batch data for one interconnector with 100MW.*

not to be associated with more investments, but should instead be related to more efficient capacity calculation methods.



Source: PCR project, including APX-Endex, Epex Spot, Nordpool, GME, OMIE (2012)

*Note: * refers to Morocco. ɔ indicates that the zone is a GME zone.*

Figure 5.4 Simulation results: gross welfare benefits from cross-border trade and incremental gain per border – 2011 (millions of euro per year)
Source: ACER (2012, figure 26, p68)

> "Figure [5.4] provides an insight into the relation between incremental and trade gains by interconnection. For instance, the figure shows that the interconnector between Sweden and Finland resulted in a trade gain of 252 million euros per year. The figure also shows which borders would benefit the most from making extra capacity available. For example, the figure indicates that additional capacity between the Netherlands and Norway would yield nearly an additional 12 million euros per year, which is an extra gain of 15%. Also, the case on the Italian–French border which has a percentage extra gain of 33% (19 million euros) is quite remarkable. In contrast, the link between Sweden and Finland has a negligible extra gain of 0.5% of the currently available capacity. Other interesting interconnector candidates for improving capacity include the following links: France-Spain, Germany-Sweden, Sweden-Poland and France-Great Britain." (ACER, 2012, pp67-8).

The incremental gain from more efficient use of interconnectors in this ACER model is exactly the same as the efficiency from market coupling we have been measuring. To take the specific examples mentioned in the quotation above, an extra 1 (not 100) MW of NL-NO capacity would be worth €1.25 million/MWyr, and IT-FR would be worth €1.9 million/MWyr. A simple sum shows that an extra 100 MW capacity on each of the 35 borders in Figure 5.3 would deliver gross benefits of about €124 million per year. This is equivalent to an average of €3.5 million per 100 MW of extra interconnector per year, or €35,000/MWyr. But a selective choice of the interconnectors to expand would greatly exceed this average, suggesting that a value of €50,000-€150,000/MWyr for improving coupling on the most inefficient borders is not unreasonable.

The earlier estimate of the gains from increasing cross-border trade from 10% of consumption to 15% of consumption assuming an average price difference before and after trade of €10/MWh (i.e. an annual value of €80,000/MWyr) might be worth 1% of annual consumption. This might be an under-estimate if some fraction of trade is in a perverse direction, as in practice it usually is prior to coupling. Our estimate above of 1.5-2.5% of wholesale electricity value therefore seems reasonable.

To attribute those economic gains to markets already coupled, and those that will be coupled in future, we made an estimate of the proportion of interconnector NTC in the EU (for these purposes, including Switzerland and Norway) that is coupled, weighed by the market sizes that are coupled. We calculated a range, varying from giving a half weighting to links, to equally weighting all links coupled in some way. This suggested that 58% - 66% of market is currently effectively coupled. Thus roughly 58% to 66% of the economic value of market coupling has already been achieved, and a further 34% - 42% will become available as all the interconnectors in the EU are coupled.

5.3 THE BENEFITS OF FUTURE MARKET INTEGRATION BEYOND 2015 TO 2030

5.3.1 Introduction: Methodology and Scenarios

A reduced model of European Electricity Transmission System illustrated in Figure 5.5 will be used for our analysis. The model covers major transmission connections between and within all current European Member States plus Norway, Switzerland, Croatian, Bosnia and Herzegovina. The model also consists of existing and potential new transmission connections. The effect of modelling used this reduced model is likely, according to the references in our literature study, somewhat to underestimate the benefits of integration by an amount in the range 1%-3.5% of system costs.

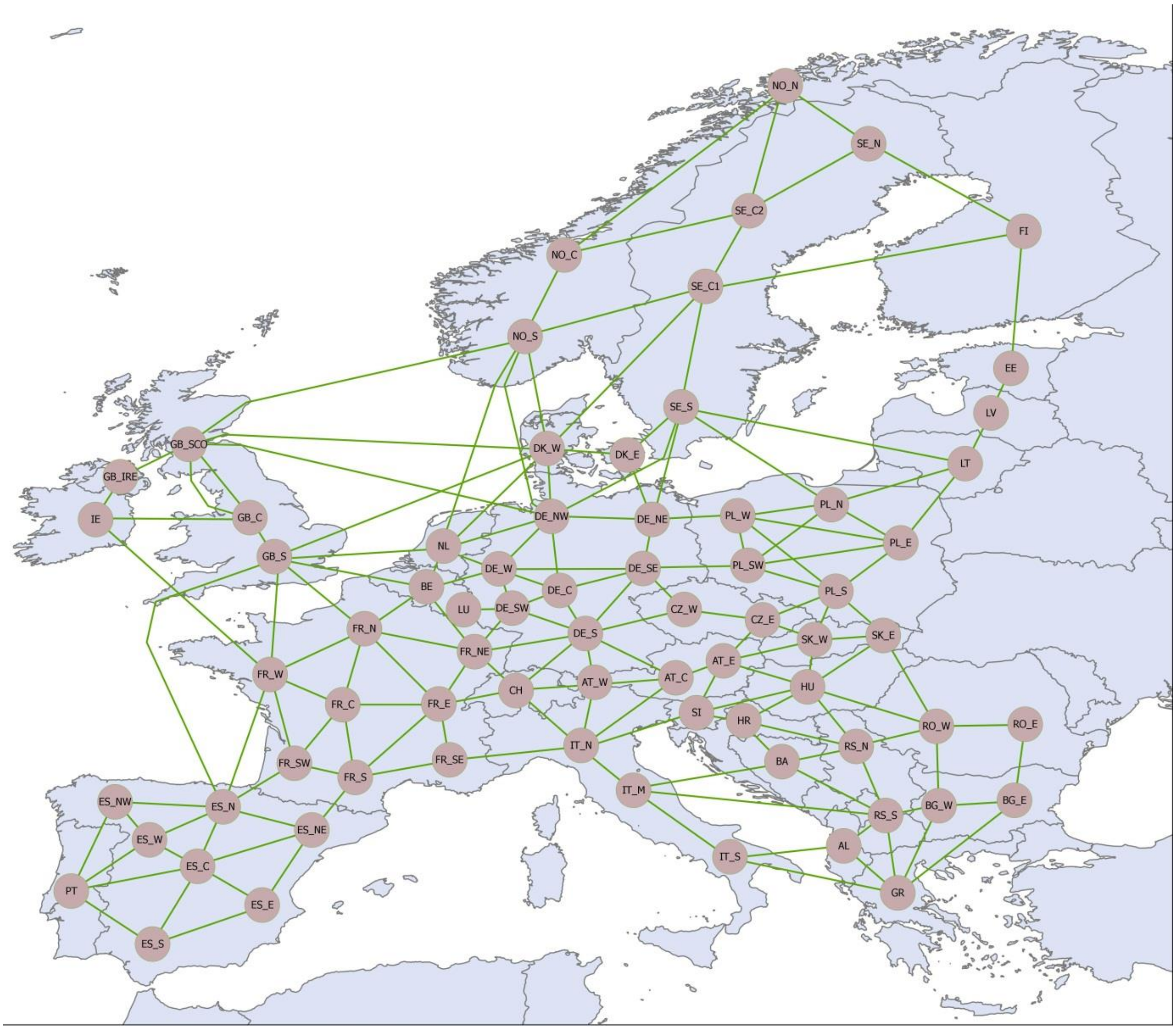


Figure 5.5 A reduced model of European Electricity Transmission System[34]

As background to understanding the results of the electricity modelling, we here summarise the market and policy scenarios we are studying.

Our studies of the market beyond 2015 are carried out on the basis of a number of background ***market scenarios***, which were described in greater detail previously. These are future scenarios for the energy market in terms of demand and generation mix by country. At an overall level, they specify a quantity of generation sufficient to satisfy the demand of Europe as a whole. These scenarios come from the PRIMES database provided to us for this study. The two scenarios we have studied are CPI – Continuing Policy and RES – High Renewables. These are defined at 2020 and 2030, and we have additionally formed a 2015 position, which is common for the two scenarios. We have additionally defined our own scenario we call INV, or the Coordinated High Renewables, defined in 2030 only. This scenario preserves renewables output at the same level as in the RES scenario, but reduces its capacity by 20GW through relocating the capacity to higher output locations.

---

[34] *Each region has a unique code.*

Our model is capable of calculating the transmission capacities necessary to support the generation defined in these scenarios, and the costs of operating those systems in terms of running costs and the capital costs of the generation and transmission. We can also use the model to compute the additional generation required if there were constraints on transmission capacity, or the alternative costs of operating the system when we judge that the level of integration in the market requires a different specification of the quantity of generation required. These are the basic mechanisms by which we calculate the benefits of different levels of integration. Different levels of integration are defined in terms of ***policy scenarios***.

Our baseline scenario defining the persistence of 2014 institutions is what we term the "energy neutral baseline". The reasons for this were fully explained in the previous section. In general, given the low cross-border transmission capacity existing in comparison to overall national demand levels, national self-sufficiency, or what might be termed energy neutrality, in electrical generation requirements, with only short term arbitrage, is a broad characterisation of the present situation in Europe. Whilst trade represents about 10% of total consumption, this is mainly short term arbitrage, and most countries have capacity to supply their own needs if trade were impeded. Thus it is something of a caricature, in that countries are not exactly self-sufficient, but deviations from energy neutrality are relatively small, and PRIMES does not suggest a material deviation from this. The use of this caricature for the baseline will somewhat over-estimate the effect of integration, but we note below an offsetting under-estimate from the use of a simplified transmission model.

Our policy scenario for a basic well-integrated electricity market is based upon our model's prediction of providing the necessary transmission and despatch for the basic CPI and RES scenarios, as if the electricity were being traded within one country. Our "integrated market" scenario is not the most favourable scenario we model, it is only a "basic integrated" scenario. In the basic integrated market, security of supply is shared across borders, but balancing is still carried out within national transmission systems. We consider some further enhancements to integration.

In addition to those two policy scenarios, we consider a number of further changes to the level of integration in the market. For completeness, we show the complete list of policy scenarios we are considering below:

- <u>Baseline</u> The baseline scenario takes the market scenario (CPI, RES, INV) and provides such additional generation such that energy neutrality is observed, i.e., each national market has within it the basic wherewithal to satisfy its own energy needs, and only trades to achieve short-term arbitrage. The PRIMES scenarios in fact do not deviate materially from energy neutrality.

- <u>Integrated market</u> In this scenario the basic requirements of a fully integrated market are provided for. Optimal levels of transmission will be built, because it is commercially and economically desirable to do so in a properly integrated market. Security of supply will be shared across boundaries. However balancing arrangements are still provided for within each separately managed transmission system, and there is no increased provision for peak reduction by demand management.

- Integrated with Low TX In this scenario, integration is reduced from the basic integrated case because of a lack of development in network access or insufficient cross-border transmission investment. In this scenario, only 50% of optimal new transmission capacity is constructed, but no link is reduced by more than 5GW. However whatever methods achieved the market integration of the Integrated scenario continue.

- Integrated but Self-Secure In this scenario, integration is reduced from the fully integrated case because nations explicitly provide for their own short term security of supply at a member state level. Security of supply refers to having sufficient spare capacity to be able to deal with the risk of major plant outages without involuntary demand shedding, to the standard of a maximum of 2 hours load-shedding per year. Otherwise the methods of the Integrated scenario are used.

- Integrated with EU Reserve In this scenario, integration is increased further by making some sharing of various balancing services between countries. Balancing services are very short term adjustments in supply to maintain voltage and frequency. Otherwise the methods of the Integrated scenario are used.

- Integrated with DSR In this scenario, Demand-Side Reduction (DSR) is facilitated by demand management techniques, made possible by adoption of smart grid technologies. By encouraging low-value users to curtail demand at peak times, the quantity of generation capacity required is reduced. For this scenario, we make the assumption that 10% of daily energy is flexible, and 15% peak load reduction can be achieved. Although it is an EU requirement to fit smart meters that will technically allow widespread demand side reduction, further developments are required to enable it to be implemented. If a capacity market is implemented without taking proper account of load management arrangements, then commercial incentives to implement demand management may be weakened.

These scenarios, market and policy, are summarised in Figure 5.6.

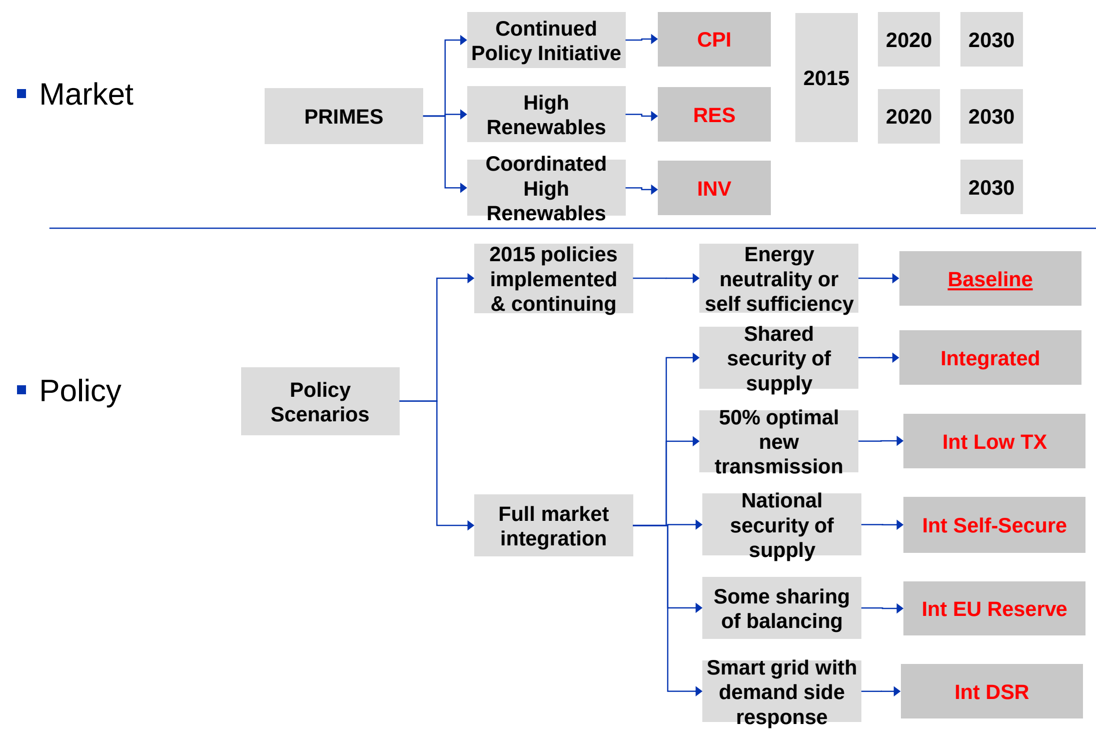


Figure 5.6 Summary of Electricity Scenarios Tested

Our transmission model is a simplified model of the European energy system, albeit that it takes into account the behaviour and complexity of the detailed networks the nodes represent. To model a dynamic despatch of the entire European transmission system is not tractably within the scope of a study of this nature. The evidence of our literature review, at least when applied to smaller parts of the EU, the effect of finer detail in models is that additional benefits of integration will be found, because certain localised difficulties are overlooked in the coarser model. In the two papers that enable one to assess it, the effect they found lay in the range of about 1%-3.5% of costs. On the other hand we have made the simplifying assumption that the baseline scenario is perfectly energy neutral, whereas in practice it is likely only to be approximately energy neutral. These two simplifications are likely to be offsetting to some degree.

5.3.2 *Cost Savings from Integration*

Our main metric of the benefits of integration is the cost savings achieved. We estimate savings as a range. This is because the PRIMES does not have sufficient generation capacity for security (or adequacy) of supply, thus we must add appropriate quantity of additional generation capacity in each scenario we study. We have two cases, first that the additional generation capacity is all peaking capacity. However in practice this capacity runs more often than is appropriate for peaking capacity, so we also consider modelling it as baseload capacity. This gives a range of values, since the reality will lie in between.

Costs measured include fuel costs, annualised generator capital costs, and annualised transmission capacity capital cost. Thus the amounts shown are net benefits, taking account of both savings in fuel and increases or reductions in the annual costs of capital stock. Generally speaking, fuel costs are much the largest component.

The cost savings in these simulations are purely the technical cost savings. An additional market gain from proper integration of markets would be increased competition to supply energy, even without changing the market structure of the present generators. Within a fullly integrated market with netting across interconnectors much more competition from one region into another can be facilitated, just as occurs within the boundaries of individual countries where there are several generators competiting in a locally integrated market. This report does not attempt to estimate what benefits might come from facilitating that additional competition.

We do not attempt to calculate incidence effects. What those are depends crucially upon the terms of trade. Governments can arrange retail markets in a way to protect groups of customers from the effects of changes in the terms of trade against them through the use of taxation and regulated charges. If Financial Transmission Rights are used as a mechanism of trade in transmission rights, changes in the terms of trade will likely be reflected in the value of those rights, and by making initial allocations of those rights to certain communities (as happens in some parts of the USA), these protections can be funded. In the past some national governments have chosen not to allocate efficiency gains in electricity markets to consumers, but rather to other parts of the economy, and governments will have such options in future.

The following graphs show the cost savings achieved in the two market scenarios, CPI and RES, we are studying. We start by reporting the results for the CPI scenario. In each case, we show net the integration benefit of the various integrated scenarios relative to the Baseline scenario, which is the energy neutral scenario. It should be understood that each is a hypothetical figure conditional upon the levels of market integration being achieved. This is particularly relevant in relation to the 2015 scenario, where it is not practical to achieve that level of integration so quickly, and the numbers indicate the potential had suitable integration measures already been implemented.

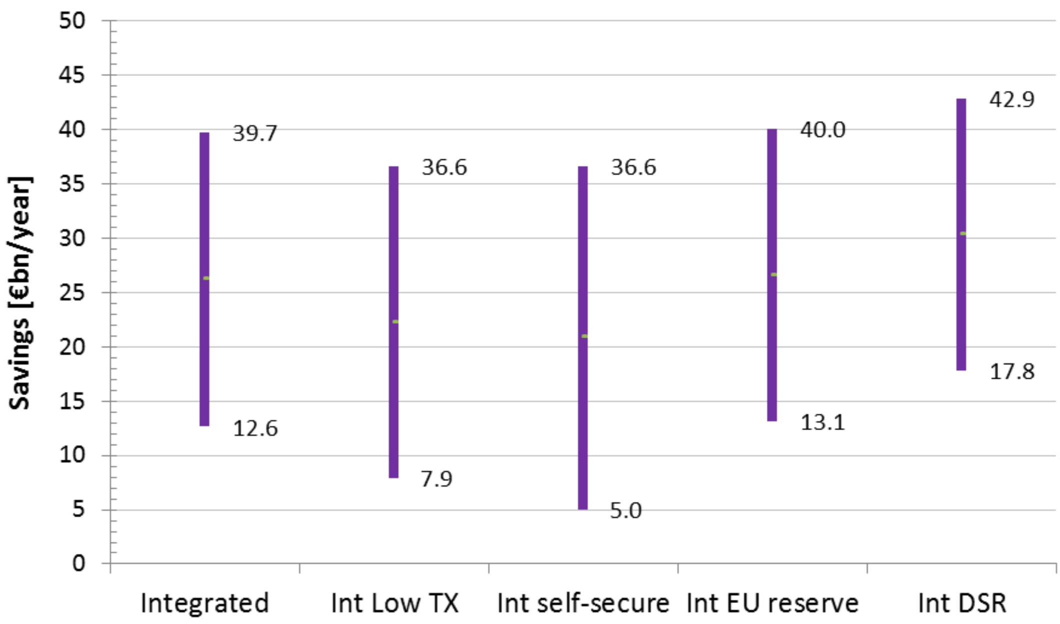


Figure 5.7: Range of annual cost savings in integration scenarios relative to baseline, CPI market scenario, 2030

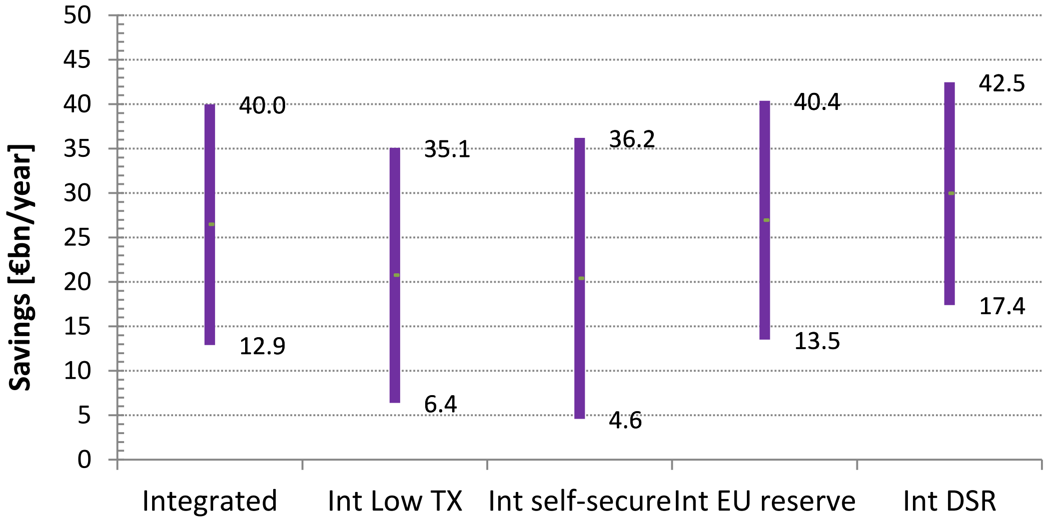


Figure 5.7A: Range of generation cost savings (capital and opex) in integration scenarios relative to baseline, before deduction of transmission costs, CPI market scenario, 2030

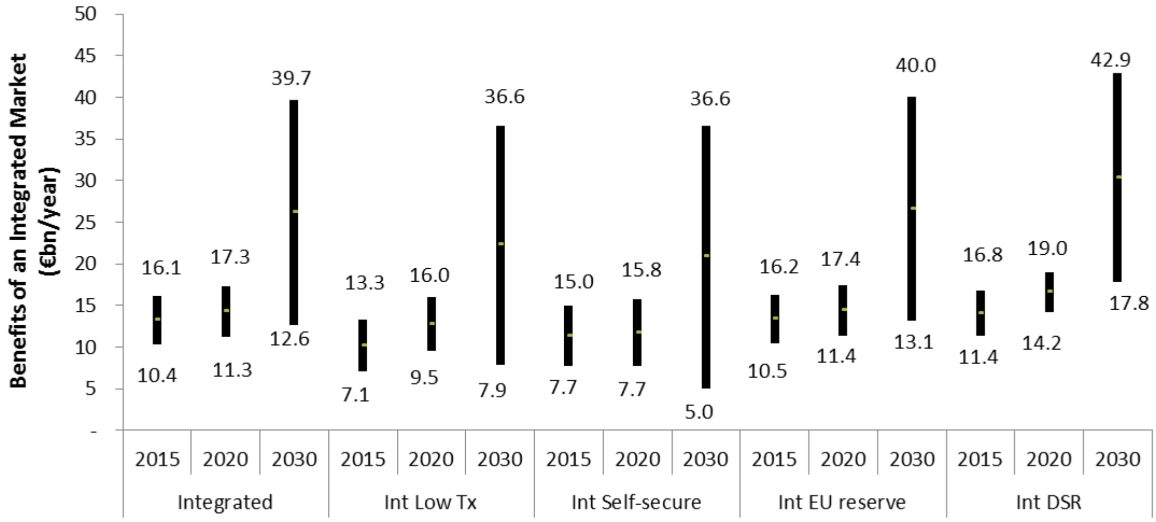


Figure 5.8: Range of annual cost savings in integration scenarios relative to baseline, CPI market scenario, 2015-2030

Figures 5.7 and 5.8 show the net cost saving benefits of the various integrated scenarios in the CPI market scenario, in comparison to our Baseline scenario of national energy neutrality. Figure 5.7 concentrates on 2030, and shows the variation by scenario. Figure 5.7A splits out the generation cost saving (capital and opex) in Figure 5.7 before adjustment for transmission capital costs. Figure 5.8 shows how this grows as time passes within each scenario. It is apparent that the cost-saving benefits of €13bn-€40bn per year in the basic fully integrated scenario in 2030 are quite substantial. There are already substantial cost savings being missed in the short run, as the 2015 scenario indicates, and this changes by a relatively small amount by 2020. The major change occurs by 2030 as major changes in the pattern of generation occur.

The Integrated but Low TX Capacity scenario indicates the effect of only about half of the additional optimal transmission capacity being built (additional relative to today), while still applying other integration measures. It can be seen that this reduces the benefits of integration less than 10%. Thus in the CPI scenario over 90% of the benefit comes from about half the optimal additional transmission capacity. So if planning or environmental restrictions do curtail the level of transmission capacity that is built in comparison to the commercial optimum, this is not serious so long as half the optimal capacity is built. Plainly it is the transmission trading institutions facilitating reliable long-term cross-border contracting in generation capacity that are far more critical for an economic optimum in plant choice than the quantities of transmission capacity. However we will see below that with reduced transmission capacity fairly large amounts of additional generation capacity must be built to retain security of supply. Thus there are broader advantages of achieving the optimal levels of transmission capacity.

The Integrated but Self-Secure scenario reduces benefits by about 8%, but (as we shall see below) further inflates the quantity of additional peak-lopping generation capacity that must be built.

The EU Reserve scenario indicates modest additional savings of about €0.3bn by 2030 resulting from some limited shared balancing. Although these savings are modest in terms of other figures mentioned here, they would be easy to obtain, even as an increment from the present market situation. There appears to be some greater willingness and commercial incentive for arrangements for cross-border sharing of balancing resources. The saving in generation capacity is modest but worthwhile. But whilst this might appear to be a relatively easy integration benefit to obtain, it remains small in relation to the main prize.

In the DSR scenario, with increased demand-side management facilitated by smart metering and other techniques, quite worthwhile additional savings of around 8% are obtained, and quite large reductions in generation requirements (see below). The commercial incentives to implementation of demand management techniques risk being undermined if capacity markets fail to take proper account of it.

In the following details, we concentrate on the case which supports the upper end estimate of cost savings, i.e. the case where all the additional capacity to provide security is peaking plant. Figure 5.9 shows the change in output by technology between the baseline scenario and the integrated scenario in CPI 2030. With running costs dominating, the main difference is that through lack of integration off-merit plant is being scheduled to run in the baseline scenario. In the integrated scenario, increased quantities of energy are obtained from baseload nuclear and coal plant, and high cost short term oil and other peaking plant is displaced in substantial quantity.

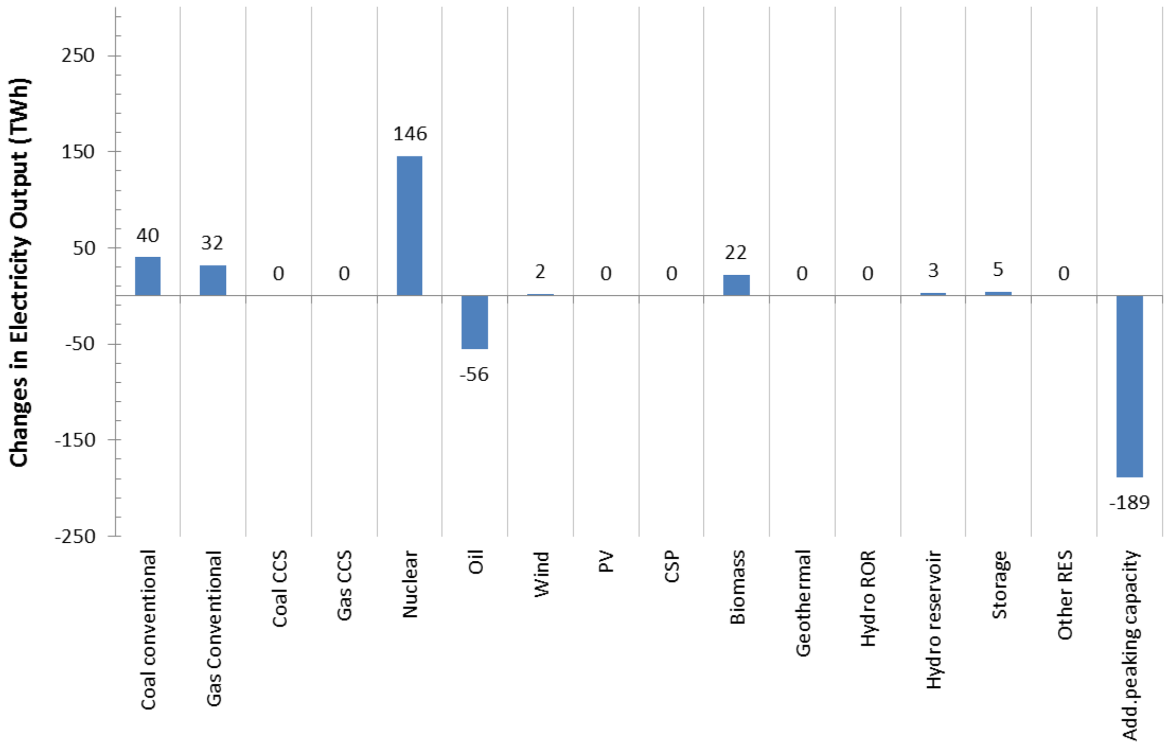


Figure 5.9: CPI 2030 Integrated Scenario change on Baseline Energy Neutral Scenario, energy output by technology

In the following, we present the same set of results for the RES market scenario, which has an increased quantity of renewable generation.

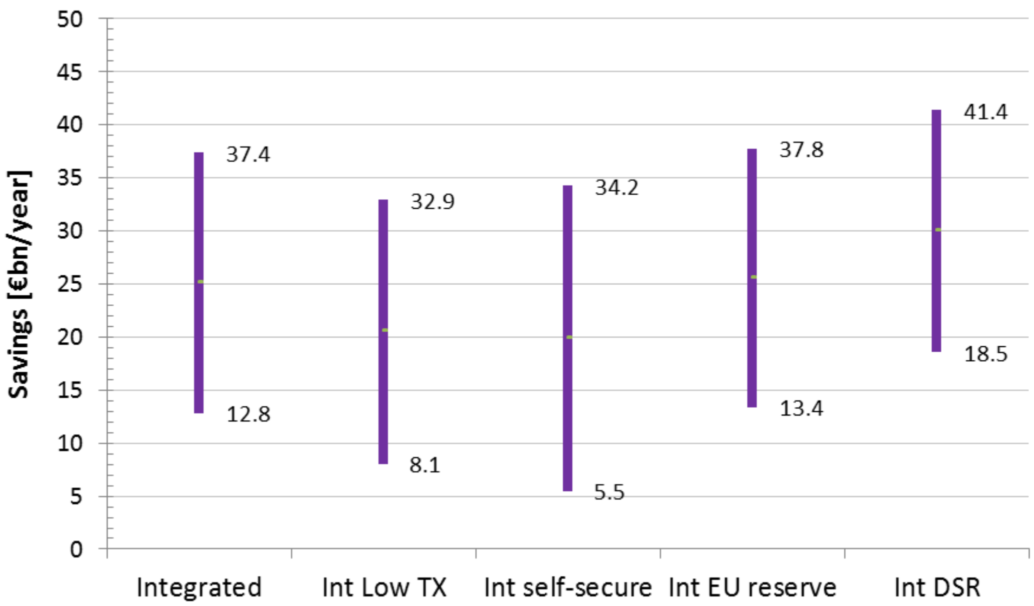


Figure 5.10: Range of annual cost savings in integration scenarios relative to baseline, RES market scenario, 2030

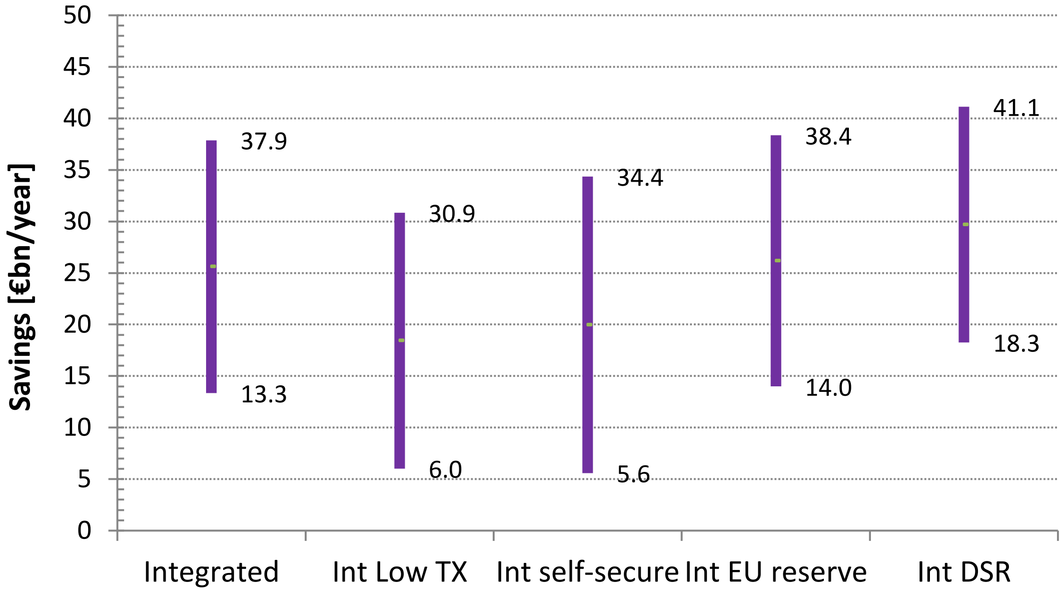


Figure 5.10A: Range of generation cost savings (capital and opex) in integration scenarios relative to baseline, before deduction of transmission costs, RES market scenario, 2030

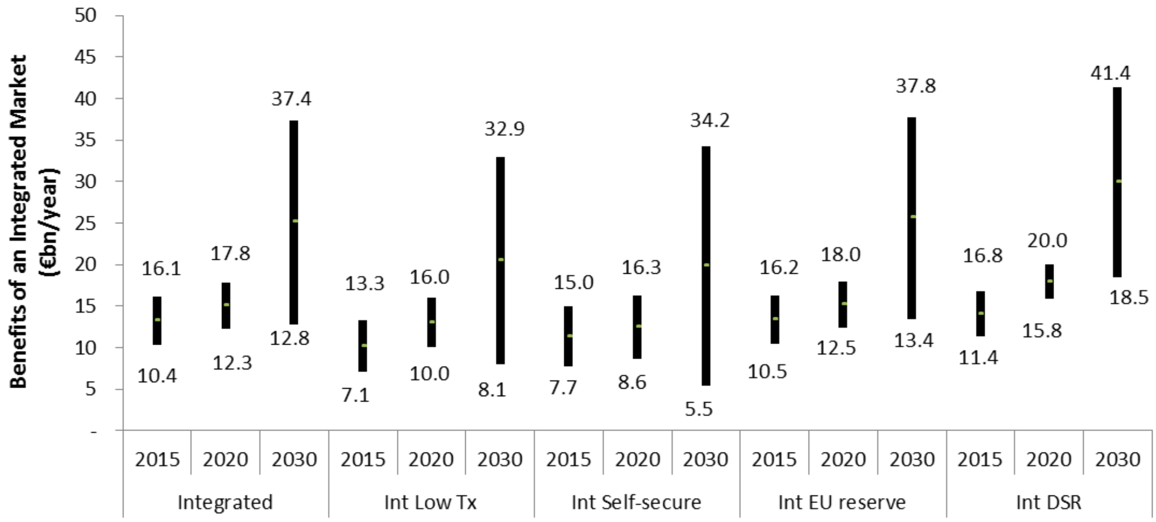


Figure 5.11: Range of annual cost savings in integration scenarios relative to baseline, RES market scenario, 2015-2030

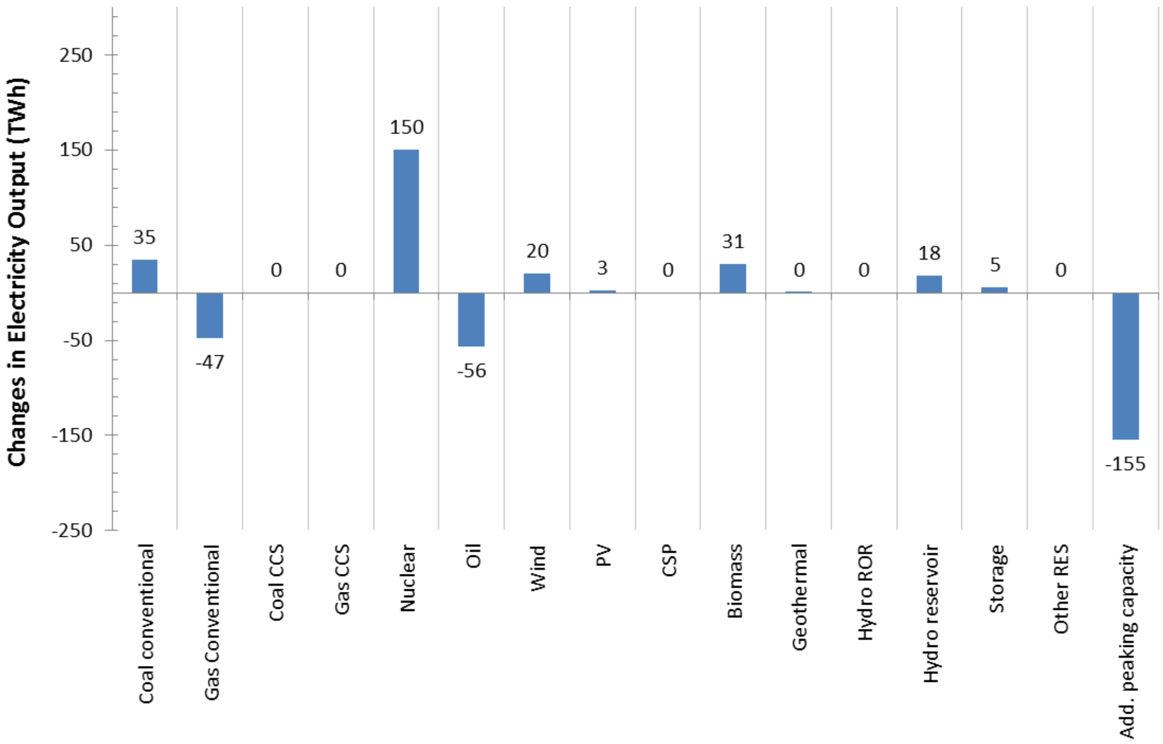


Figure 5.12: RES 2030 Integrated Scenario change on Baseline Energy Neutral Scenario, energy output by technology

It can be seen that broadly the same patterns and magnitudes exist for CPI and RES. Thus market integration will have similar benefits whether the future world is represented by CPI or RES. The details of comparison are more clearly seen from the comparison chart at Figure 5.13 which follows. Figure 5.12 indicates an interesting difference, in that in integrating in the RES scenario the integration facilitates the displacement of not just peaking and oil plant, but also baseload gas plant too, through more effective use of intermittent and cheaper baseload plant.

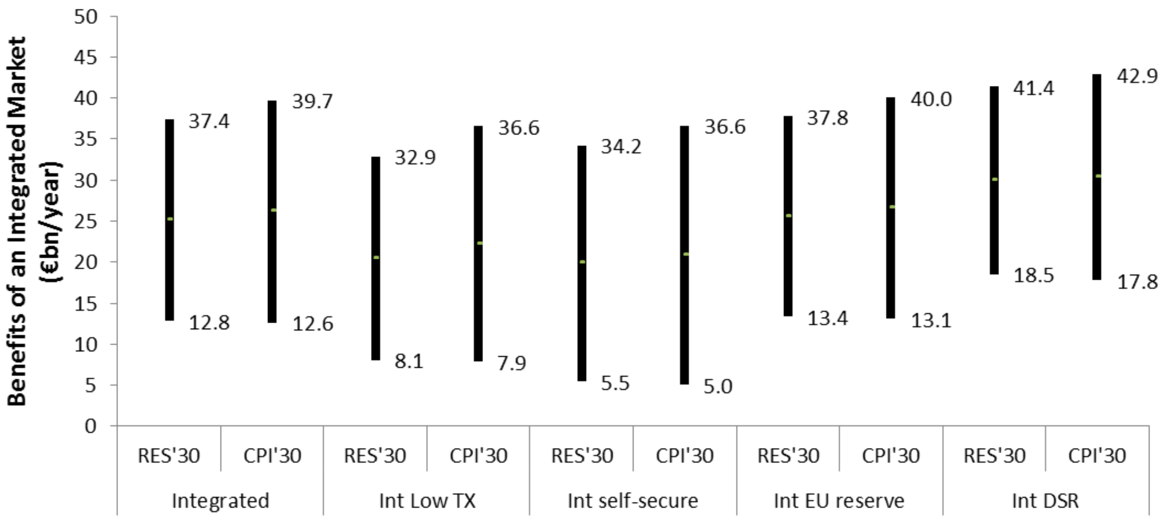


Figure 5.13: Range of annual cost savings in integration scenarios relative to baseline, CPI vs. RES market scenario, 2030

It can be seen that in general the net benefits of integration in the RES scenario appear less than in the CPI scenario. This is because the RES scenario includes more capacity that costs very little to operate – wind, etc. Thus in general the short term costs of generation are lower in the RES scenario – the short term cost plant has been built whatever the economic case for it. Thus since the costs of failing to integrate are dominated by fuel costs, the costs of failing to integrate are lower in a scenario where plant has lower fuel costs.

But we can also see that moving from the Integrated scenario to the Low TX scenario is more costly for RES, and the benefit of moving from the Integrated scenario to DSR is greater for RES. With high renewables, the effect of changes in the level of market integration are greater than in the CPI scenario. This is because renewable generation is more variable, and less well matched in location to demand, thus its efficient allocation is more dependent upon the proper working of markets.

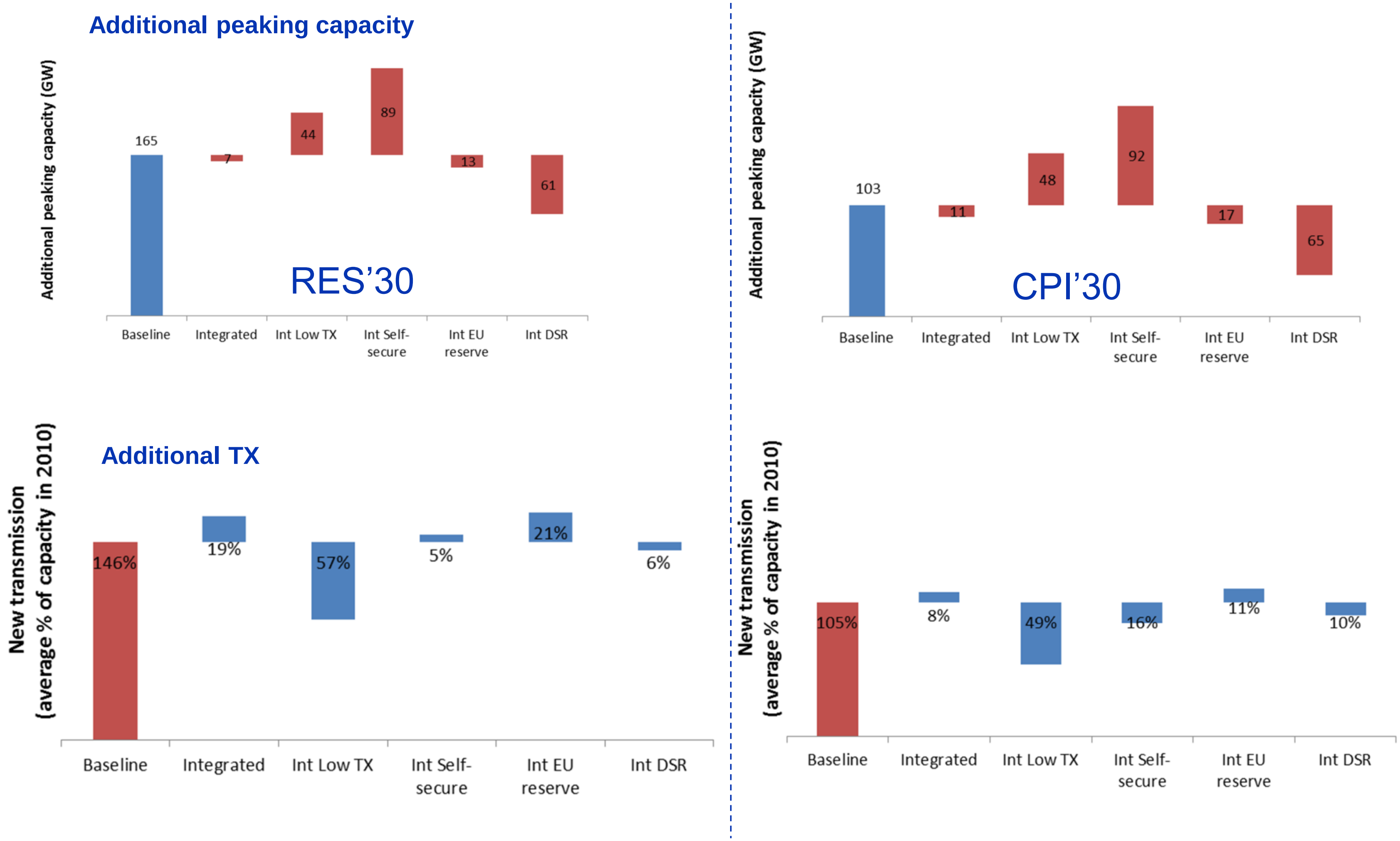


Figure 5.14: CPI and RES 2030: Investment in additional firm generation capacity needed to maintain security of supply, and additional transmission capacity required

5.3.3 *Generation and Transmission Infrastructure Required*

Figure 5.14 shows the additional generation capacity required in each scenario in 2030, for both CPI and RES, to deliver security of supply, and also the optimal additional transmission capacity. The additional transmission capacity is shown as a %age increment on the existing quantity in existence at 2010.[35] To convert the given %age figures to absolute quantities of transmission capacity, the quantity in existence at 2010 is taken to be 69 TW-km.

The quantity of additional generation capacity for security of supply above PRIMES is quite large even in the baseline case. Although we noted earlier that over 90% of economic benefits come with about 50% of additional transmission capacity, the impact of that shortage of transmission capacity on the additional generation capacity required is quite large. The impact of national self-security policies is larger still. Demand side management through smart grids is very effective in combating the requirement for additional generation capacity.

It can also be seen that quite substantial amounts of additional transmission capacity are desirable even in the baseline case. The ENTSO-E plan for 2020 is based upon a 40% increase in transmission capacity from the current base, and this 40% increase is adequate for the 2020 scenarios. Thus it can be seen that it is important to achieve the ENTSO-E plan for transmission capacity, and to continue building capacity at a similar or even somewhat higher rate in the following decade. The adjustments to optimal transmission capacity for the various scenarios are relatively modest in terms of that overall general desirability of greatly increasing the quantity of interconnection capacity.

(a) CPI 2030 (b) RES 2030

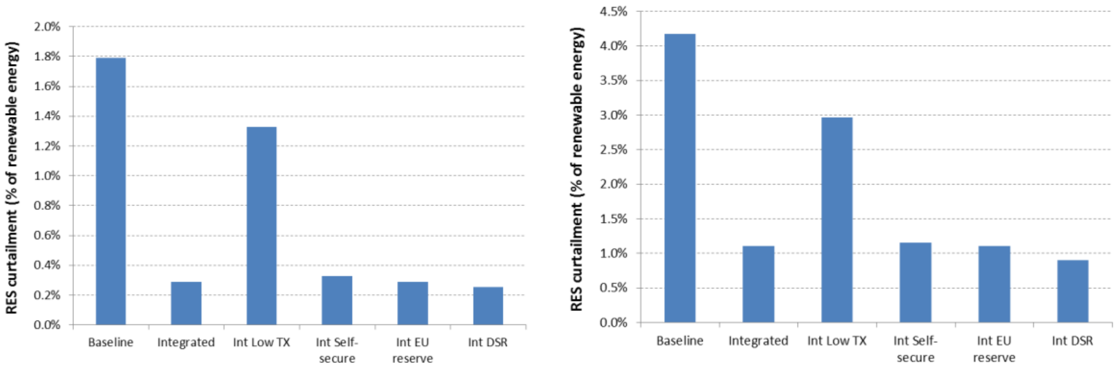


Figure 5.15: Curtailment of renewables CPI vs. RES market scenario, 2030

Curtailment is when the quantity of transmission capacity available is insufficient to deliver the amount of renewable energy that may be instantaneously available due to variations in weather, since it is not economic to build so much transmission capacity to be able to deliver it all. Figure 5.15 shows the amount of curtailment of renewable generation in each scenario. Curtailment is currently low, but will necessarily increase as the proportion of renewables in the system increases. It can be seen that the integrated scenario reduces the amount of

[35] *Geographic length of the interconnectors is taken into account, so transmission capacity is measured in TW-km rather than GW: For example, 1000km of 1GW interconnector has a capacity of 1TW-km.*

curtailment in the well-integrated scenarios in 2030 by a factor of around 4 to 8 from baseline.

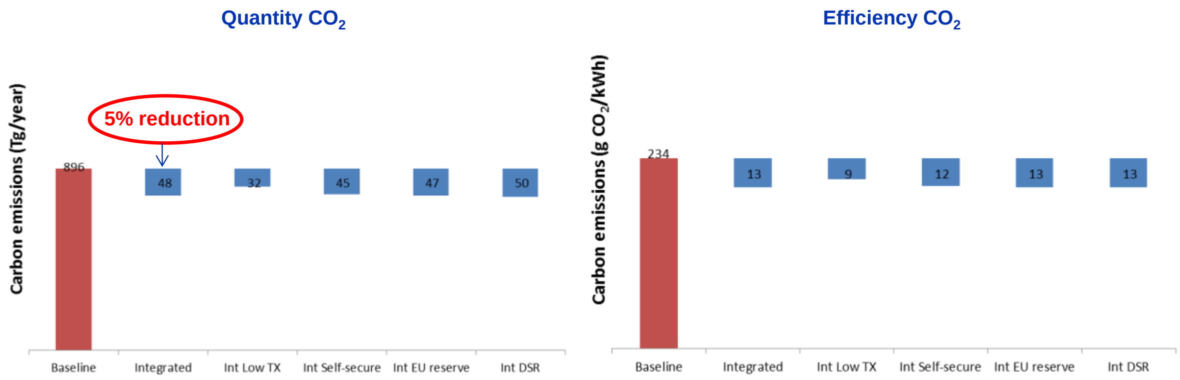


Figure 5.16: CPI 2030 CO_2 Emissions: Total, and Amount per kWh

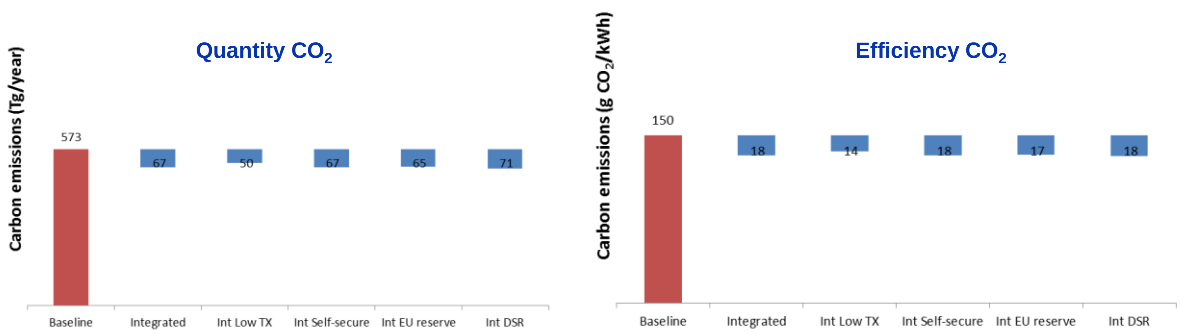


Figure 5.17: RES 2030 CO_2 Emissions Total: and Amount per kWh

Figures 5.16-5.17 shows the CO_2 emissions in each scenario. It can be seen that the integrated scenario reduces CO_2 by about 5% in the CPI scenario and about 12% in the RES scenarios. As the comparison between the quantity and efficiency charts show, the reduction in CO_2 is related to the intensity of emission per kWh, rather than due to quantity of energy. In effect, greater efficiency can be achieved through integration. Other integrated scenarios produce relatively little difference, apart from the Low TX scenario materially reduces the benefit. Again we see differences are larger in the RES scenarios - integration becomes more valuable in a high renewables world.

5.3.4 *Renewables Investment Coordination*

We have also examined the INV 2030 scenario, where 146GW of renewables capacity from the RES 2030 scenario can be saved without reduction in energy output by relocating it. Figure 5.18 shows that net savings of about €16bn - €30bn a year (after netting out the effect of additional transmission costs and some generation cost savings, shown in the right hand bars in the chart) would be achieved by this relocation, the range reflecting a range of costs for PV capacity.[36] Some additional transmission capacity is required to facilitate the

[36] *We observe that Siemens AG has carried out a similar exercise and made a rather smaller estimate, being in the range of €30bn - €45bn cost saving in total npv as opposed to our €16bn - €30bn annual savings cost. However the details of the*

relocation, but at a small fraction of the cost of the capital savings in the generation capacity. There would also be some additional operating costs, following from the increased curtailment of the renewables which would have to be covered by some additional peaking plant. This is because an optimal transmission system does not seek to provide capacity for all flows, and the amount of flows it is not cost-effective to satisfy is likely to increase as greater fluctuations are placed upon the system.

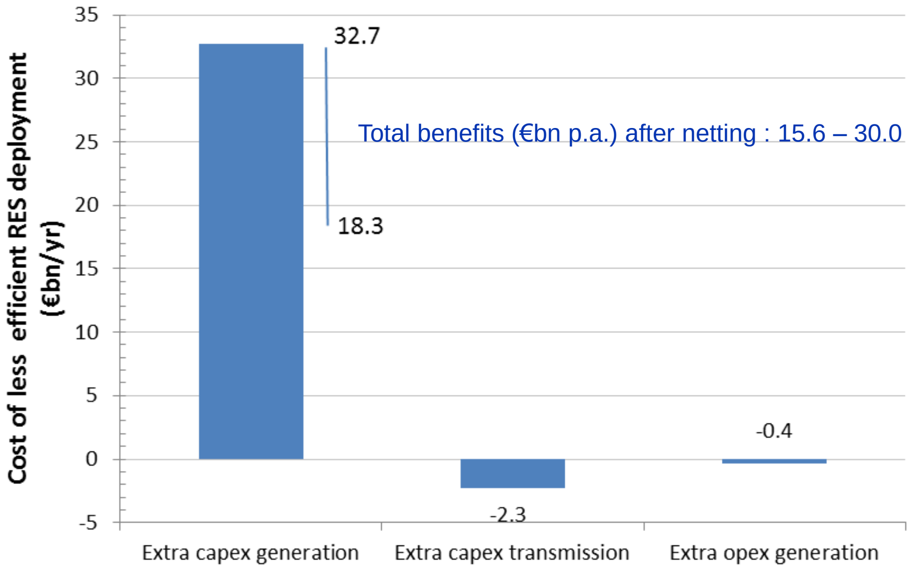


Figure 5.18: INV 2030 Cost benefit of relative to RES 2030

Figure 5.19 shows the change in optimal transmission capacity requirements by node pair for INV 2030 in comparison to RES 2030. It can be seen that the effect is not merely strengthening, rather about as many node pairs can be reduced in their capacity, though by a smaller amount than other node pairs require strengthening. Some of the links require very substantial strengthening, 20GW or so, reflecting that some regions would, in a fully integrated market, find it economically advantageous to export large quantities of renewable energy. Such export would be far cheaper than generating it locally to the demand instead.

---

calculation are not made clear. See Siemens AG presentation "Competitive Energy Landscape in Europe", M Suess, 14 May 2013.

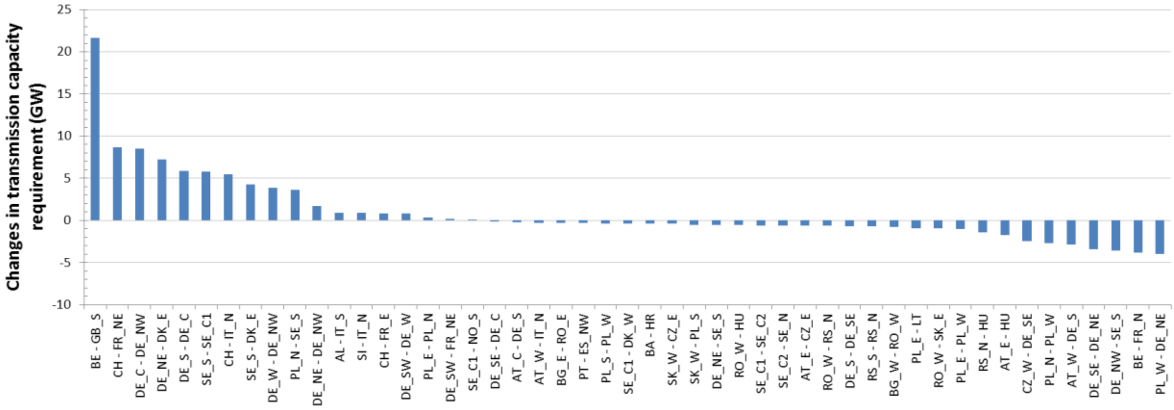


Figure 5.19: INV 2030 Change in optimal transmission capacity by node pair relative to RES 2030

5.3.5 Synthesis and Conclusions

During the period since 2004, the main integration initiative in the electricity market has been the introduction of Target Electricity Model, based on the market coupling approach, which is intended to be extended to the entire European electricity market by 2014, although there may in practice be some delay. We have estimated that the benefits of the integration due to market coupling, once market coupling is fully implemented across the EU, will be of the order of €2.5bn to €4bn per year, or about €5 to €8 per capita per year. About 58%-66% of this benefit has already been achieved due to the level of market coupling already present, especially in the large electricity markets of NW Europe and the Nordic region. The remaining 34%-42% should be achieved with the completion of the Target Electricity Model.

But market coupling is delivering only the benefits of short term arbitrage in energy trading. The Target Electricity Model thus only partially delivers a fully integrated electricity market, which would facilitate the long term and short term trading of energy, balancing services and security of supply without regard to political boundaries. We have found that much larger gains can be obtained if the market is truly integrated, which would require the adoption of much deeper market methods of integration, such as the use of Financial Transmission Rights. We have assessed only the technical gains: further gains could come from the effect of increased competition in generation which would be facilitated in a properly integrated market.

In €bn/year (rounded)	2015	By 2030
Integrated	10.0 to 16.0	12.5 to 40.0
Reduction for 50% less TX investment	-3.0 to -3.5	-3.0 to -5.0
Reduction for self-security	-1.0 to -3.0	-3.0 to -7.5
Extra for shared balancing	ca 0.1	0.3 to 0.5
Extra for Demand Side Response	0.5 to 1.0	3.0 – 5.0
Extra for Coordinated RES investment	n/a	15.5 to 30.0

Figure 5.20: Summary of the net benefits of market integration from 2015-2030, taking into account the variety of scenarios studied

In Figure 5.20 we summarise the net market integration benefits that could be achieved, in round figures. €1billion per year translates into €2 per capita per year, so a simple conversion from the figures in the table above to per capita figures is available if desired. The 2015 figures indicate what could have been achieved if markets had already been fully integrated, although plainly on that timescale that will not happen. The 2030 figure shows how that can grow over the following 15 years if in fact market integration is achieved.

The first line of the table shows the net benefits of achieving basic market integration. Each further row shows the adjustment that should be made to that for each of the conditions mentioned. These can be added up if more than one applies. It can be seen that integrating the market delivers the largest benefits, in the range of €12.5bn to €40bn per year by 2030. At the upper end, around 90% of the net benefits will be achieved even if the increment in transmission capacity is only half of what is optimal. A similar reduction in benefit would apply if countries seek to achieve security (adequacy) of supply at a national level. Some modest benefits would come from sharing balancing reserves. And material gains of the order of €4bn could come from using smart grids to facilitate demand side response at the consumer level. Large gains of €16bn-€30bn a year are available if there is a true common market for renewable energy as envisaged by the Renewables Directive. This will be achieved by making it commercially desirable to locate renewable generation capacity in locations that are most effective for it. This will make it economically desirable to build the transmission capacity necessary to support it.

Achieving this will require tough political decisions to be made. Political buy-in from member states so that they will be willing to facilitate this level of integration requires them to have confidence in the integrated market to deliver the energy and security of supply their constituents desire, as they would if they were representing just a small part of a larger country, thus to breaking out of the self-sufficiency mind-set that most countries still retain.. Energy markets, renewables markets, and capacity markets need to be truly international if cost savings are to be achieved while maintaining security of supply and renewables targets. However once embarked upon it is a route of low regret. The benefits are large and relatively insensitive to different market scenarios. Incidence effects are driven by the terms of trade, and mechanisms are available to protect negatively affected parties, if governments choose to employ them.

Full integration will require large investments in transmission capacity, albeit not much larger than is already desirable without it. But this is much cheaper than the alternative of further investment in generation capacity. The ENTSO-E plan of a 40% increase by 2020 is fully adequate. However this rate of investment needs to be maintained to 2030. However use of smart grids to facilitate Demand Side Reduction will materially reduce the requirement for additional transmission capacity. And around 90% of economic benefits of integration are achievable even if only half the optimal increment of transmission capacity is built.

6. LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators – a body set up under EU Regulation to carry out certain community tasks in the EU energy market, especially in relation to network rules
bcm	Billion Cubic Meters – volumetric measure for quantities of gas
CPI	A PRIMES (qv) scenario referring to Continued Policy Initiatives
DSR	Demand Side Reduction – any method of responding to peaks in demand which is achieved by arranging with customers to reduce their demand voluntarily rather than running additional generating capacity
EC	European Commission
ENTSO-E	European Network of Transmission System Operators of Electricity
ENTSO-G	European Network of Transmission System Operators of Gas
EU	European Union
EU27	Represents the 27 member states of the European Union
FAPD	Flow Against Price Differential – an inefficient use of an interconnector where the net flow is in the opposite direction to what the price differential would indicate, consequent upon lack of proper integration of the market
FID	Financial Investment Decision
IFA	Interconnexion France-Angleterre, the France-UK electricity interconnector
INV	A market scenario ("renewables INVestment coordination") we have devised based upon the RES PRIMES scenario, which has the same renewal energy output, but with 74GW of capacity eliminated by relocating capacity to geographical locations where it would have a better load factor
LNG	Liquefied Natural Gas
mcm	Million Cubic Meters – volumetric measure for quantities of gas
MWh	Megawatt hour – a measure for energy content of gas or electricity, 1000 kWh
NW Europe	North-Western Europe
NBP	National Balancing Point – the gas trading hub in the UK
NCG	NetConnect Germany – a gas trading hub in Germany

NTC	Net Transfer Capacity – the capacity available for allocation on an electricity interconnector
NYMEX	New York Mercantile Exchange
OCGT	Open Cycle Gas Turbine – a technology of electricity generation of low capital cost generally used only at times of high demand. Referred to in this report as a generic representative of peaking plant, rather than intending to specify the technology.
OIES	The Oxford Institute for Energy Studies – independent research centre of the University of Oxford specialising in the economics and politics of international energy
PEGs	Points d'Echange de Gaz – the gas trading hub in France
PRIMES	Modelling system that simulates a market equilibrium solution for energy supply and demand in the EU member states. (Authored and owned by the National Technical University of Athens)
PSV	Punt di Scambio Virtuale – the gas trading hub in Italy
RES	A PRIMES (qv) scenario with higher renewable generation than CPI (qv). In figures may sometimes be used as a general abbreviation for renewables.
SoS	Security of Supply
TEM	Target Electricity Model – a high level description of a system of cross-border integration in the electricity market based on market coupling, intended to be introduced fully across Europe by 2014
TSO	Transmission System Operator
TX	Abbreviation for Electrical Transmission Capacity
TTF	Title Transfer Facility – the gas trading hub in the Netherlands
TWh	Terawatt hour - a measure for energy content of gas or electricity – 1,000,000 MWh or 1,000,000,000 kWh
TWkm	A quantity of electrical interconnector capacity representing both its length and its electrical capacity, for example 1 TWkm represents 1000km of an interconnector of 1GW capacity
TYNDP	Ten Year Network Development Plan as published by ENTSO-G
UGS	Underground Gas Storage

7. APPENDIX A: DETAILED CALCULATION METHODOLOGY ON BENEFITS IN GAS MARKETS

Benefit per Country	=	Δ [$Price_{Basecase}$ & $Price_{Scenario}$]	X	$Volume_{Scenario}$
Base Case		$Price_{Basecase}$ is the actual 2012 average gas border price per country		
Scenario 1		$Price_{Scenario1}$ is the average 2012 oil-indexed gas border price (all countries)		$Volume_{Scenario1}$ is the actual gas consumption 2012 per country
Scenario 2		$Price_{Scenario2}$ is based on an assumed mix of hub- and oil-indexation of 2012 average gas border prices per country		$Volume_{Scenario2}$ is projected natural gas gross inland consumption 2015 per country (PRIMES CPI Scenario)
Scenario 3		$Price_{Scenario2}$ is the average 2012 hub-indexed gas border price (all countries)		$Volume_{Scenario3}$ is projected natural gas gross inland consumption 2030 per country (PRIMES CPI Scenario)

Figure 7.1: Calculation Methodology for Benefits on Wholesale Price Differentials

Source: Booz & Company

Benefit per Country	=	Δ [Flexibility $Price_{Basecase}$ & Flexibility $Price_{Scenario}$]	X	Flexibility $Volume_{Scenario}$
Base Case		Flexibility $Price_{Basecase}$ is the 2012 flexibility price per country (dependent per country)		
Scenario 1		Flexibility $Price_{Scenario1}$ is cost-plus based price for flexibility 2012 (estimated at €5-8/MWh) (all countries)		Flexibility $Volume_{Scenario1}$ is projected natural gas gross inland consumption 2015 per country (PRIMES CPI scenario) multiplied by the share of total volume required in flexibility (based on 2012)
Scenario 3		Flexibility $Price_{Scenario3}$ is hub-based (summer-winter spread) price for flexibility 2012 (estimated at €3-4/MWh) (all countries)		Flexibility $Volume_{Scenario3}$ is projected natural gas gross inland consumption 2030 per country (PRIMES CPI scenario) multiplied by the share of total volume required in flexibility (based on 2012)

Figure 7.2: Calculation Methodology for Benefits on Price Differentials in Flexibility

Source: Booz & Company

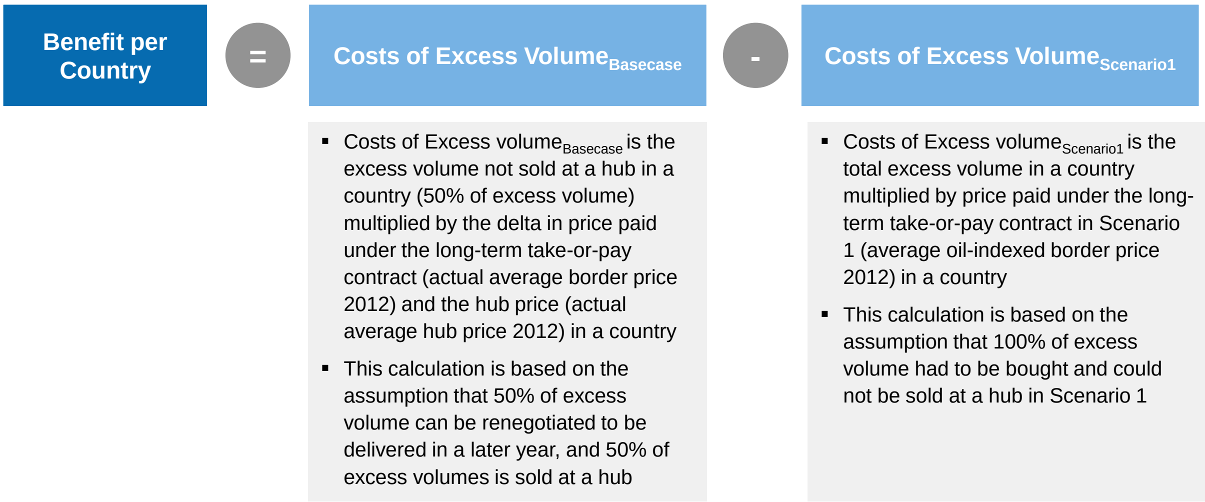


Figure 7.3: Calculation Methodology for Benefits on Costs of excess volume as a result of long-term Take-or Pay contracts

Note: In the calculation above, a "negative" outcome of the calculation above indicates higher costs in Scenario 1 than in the base case (i.e. benefits as a result of market integration)

Source: Booz & Company

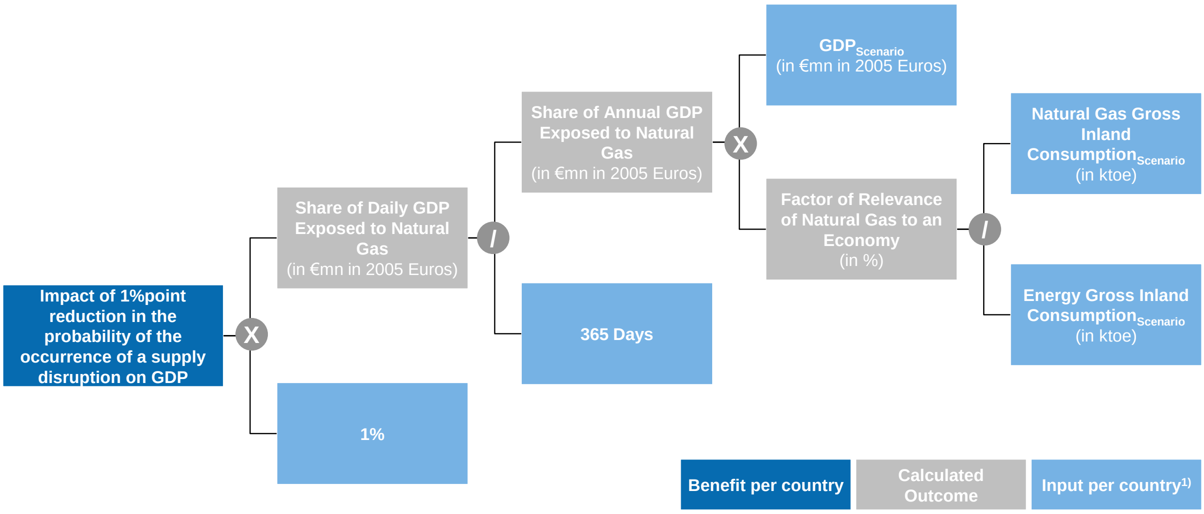


Figure 7.4: Calculation Methodology for Reduction in daily GDP at Risk of a 1% Reduction in Probability of the Occurrence of a Supply Disruption of 1 Day Duration

1) Input for Consumption and GDP based on PRIMES CPI Scenario Data (Scenario 2: 2015, Scenario 3: 2030)

Source: Booz & Company

8. APPENDIX B: THE BENEFITS OF MARKET COUPLING

8.1 MARKET COUPLING OF DAY-AHEAD MARKETS

One of the main aims of the Target Electricity Model (TEM) is to facilitate more efficient trade in electricity between Member States, in the short, medium and longer term. Compared to our benchmark starting year of 2004, by 2014 the TEM aims to deliver more efficient use of interconnectors by market coupling day-ahead and intraday, and also to allow balancing services to be traded across borders. As part of improving efficiency, the TEM anticipates that longer duration contracts for transmission rights should either be issued as Financial Transmission Rights (FTRs) by TSOs (the better option) or encouraged to emerge in response to market forces, e.g. as Contracts for Differences on the Nordic model (less attractive as less liquid and not naturally hedged). Long term cross-border contracts, particularly FTRs with a tenor of 2-3 years, are essential if large consumers are to feel confident about importing power, and are hence critical for making otherwise often dominated local markets contestable. In the medium and longer run, the aim is to improve the coordinated planning of transmission investments to achieve EU benefits, and to build more transmission capacity where its social benefits exceed costs.

Of these various developments market coupling of the day-ahead market is the most advanced, and the subject of this part of the report. Intraday trading and sharing balancing services are both important, and have been the subject of various studies that attempt to measure their costs and benefits.

The aim of this appendix is to quantify the benefits of improving existing interconnector use. Although this is moderately simple in theory, it is quite complex in practice, for a number of reasons that will be discussed more fully below. The main problem is the lack of the right kind of data and the difficulty of specifying the counterfactual. Given these difficulties, it is sensible to examine alternative more readily available metrics of the success and impacts of increased market integration. The main finding is that the gains from market coupling are considerable in absolute terms, and at least an order of magnitude larger than the costs, while recognising that they are small when compared to the total value of wholesale turnover. For example, the benefits of coupling the 2 GW French-England interconnector (IFA) might have been about 25% of the value of total potential trade in 2011, or some €23 million, and slightly less at €20 million in 2012. To put this in rough perspective, the UK consumes about 320 TWh and France over 500 TWh, out of the EU total of 3,165 TWh. At, say, €50/MWh, the wholesale value of UK electricity consumption is €16 billion and of France is somewhat more than €25 billion. The gain in coupling IFA is therefore 0.14 of 1% of UK consumption and about 0.09 of 1% of French consumption (recognising that there are other interconnectors in each case and that the total improvements will be multiples of these figures).

This appendix sets out a limited number of estimates of the losses on interconnectors that are not yet coupled. To summarise the patchy evidence, the losses from a failure to couple are perhaps 15-25% of measured trade. If that result holds more generally then one can gain a rough estimate of the EU-wide losses. EU exports (and imports) in 2011 were about 315

TWh[37] out of 3,080 TWh supplied (or about 10%). At the reference price of €50/MWh, the total value of trade is about €16 billion/yr., and losses might be 1.5-2.5% of the total wholesale value of electricity consumed, or €2-4 billion/yr. This is probably an overestimate as the Nordic market has always been moderately efficiently interconnected, and as this total includes the central European members who are unlikely to all couple by 2014.

8.2 THE POTENTIAL GAINS FROM TRADE ACROSS INTERCONNECTORS

To gain some idea of price differences between interconnected countries, figure 8.1 shows that although prices move in sympathy, driven by common fuel price movements as well as the ability to trade, they also diverge, particularly Spain and GB that are weakly interconnected to France.

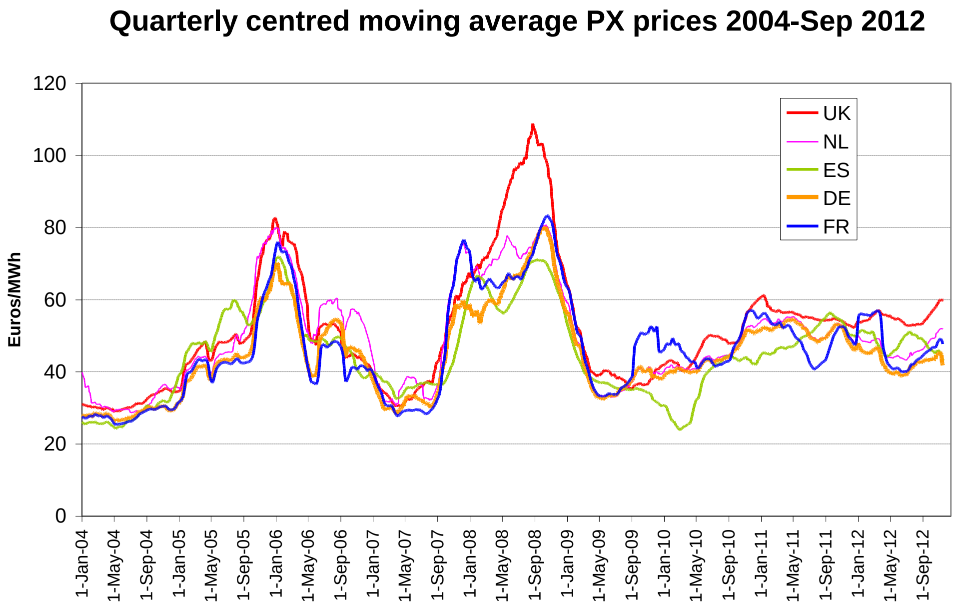


Figure 8.1 Average day-ahead prices in various neighbouring countries

Figure 8.2 demonstrates that the relevant interconnectors experienced large absolute price differences over this period. These figures suggest that the annual value varies between more than €50,000 to perhaps €150,000/MWyr or between €6-17/MWh, and suggests that the cost of not fully using available interconnector capacity could be very considerable.

37 *http://epp.eurostat.ec.europa.eu/statistics_explained/index.php?title=File:Electricity_Statistics,_2011_%28in_GWh%29.png&filetimestamp=20121128151011*

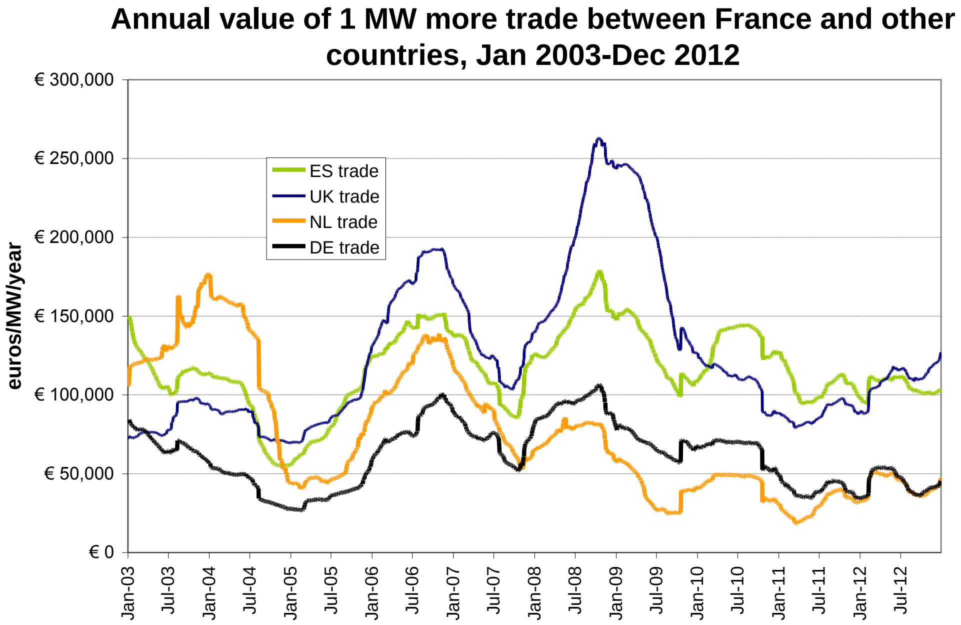


Figure 8.2 Valuing trade over interconnector per MW of extra capacity used

8.3 THE INEFFICIENCY OF EXPLICIT AUCTIONS FOR INTERCONNECTORS

Market coupling ensures that interconnectors are more efficiently used by simultaneously clearing their capacity with all bids and offers into the day-ahead auction. Before interconnectors were coupled, traders had first to secure capacity ahead of time on the interconnector, based on a prediction of likely price differences across the interconnector, and then offer or bid into the power exchanges on each end of the interconnector. In addition to daily auctions, most interconnectors also ran month, quarter and/or year ahead auctions for capacity, which could be nominated the day-ahead, if valuable, or withheld if not. The result of these various contracts ahead of time depended upon the rules of operating the interconnector, the liquidity of the various markets (for contracts and in the power exchanges) and the predictability of the price differences across the interconnector (and hence the direction of flows).

In the best case one country would be systematically cheaper than another, so that it would always be sensible to purchase and use all the available capacity. In other cases, price differences and flow patterns may be hard to predict even day ahead, with many traders purchasing export capacity ahead of the opening of the power exchanges, after which the prices signal that importing would be desirable (or *vice versa*). If there is still time after the day-ahead power exchange closes to renominate generation and demand contracts, and using the interconnector has been revealed to be unprofitable, and if the contract to use the interconnector took the form of a Physical Transmission Right (PTR), which is an option but not the obligation to flow power, then the trader could step away from the contract and not flow power, so the interconnector would be unused in the export direction. In the worst case the power would be required to flow as contracted, and would amplify the price differences across the interconnector.

As we are considering the move from the *status quo* in 2004 to full market coupling, there is no need to consider intermediate improvements in operating interconnectors, of which Use it or Sell it (UIOSI) was the most valuable. This allowed holders of longer-term contracts for the use of the interconnector to either nominate flows day ahead, or if they chose not to nominate, then the capacity would be allocated to the day-ahead interconnector auction, and any positive price would be credited to the original contract holder.

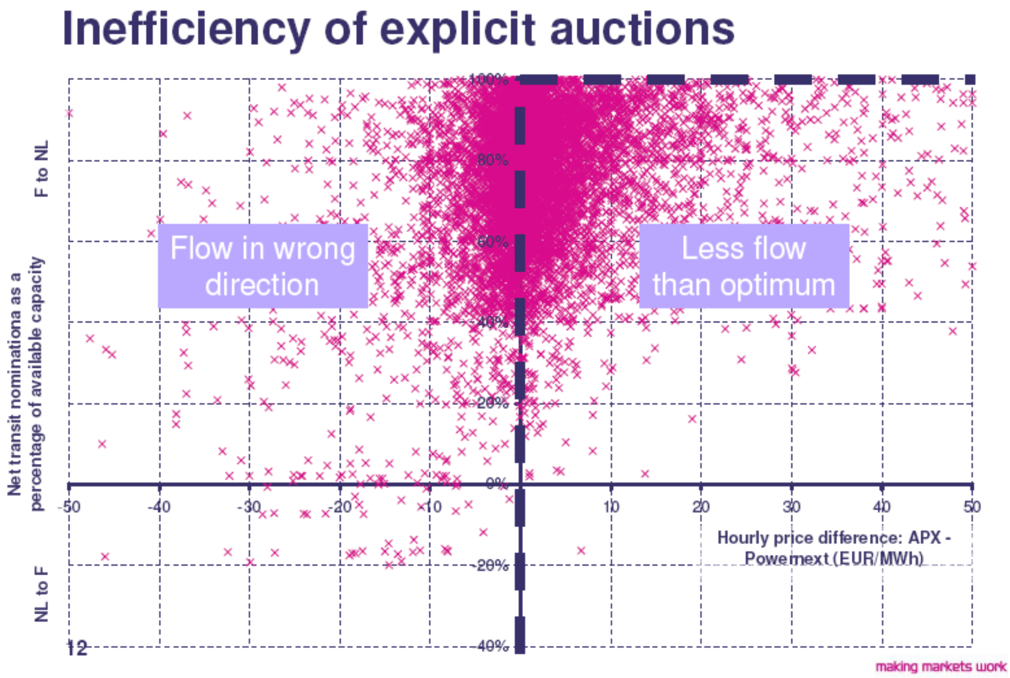


Figure 8.3 Price differences and utilisation of the NL-FR interconnector
Source: Moss (2009)

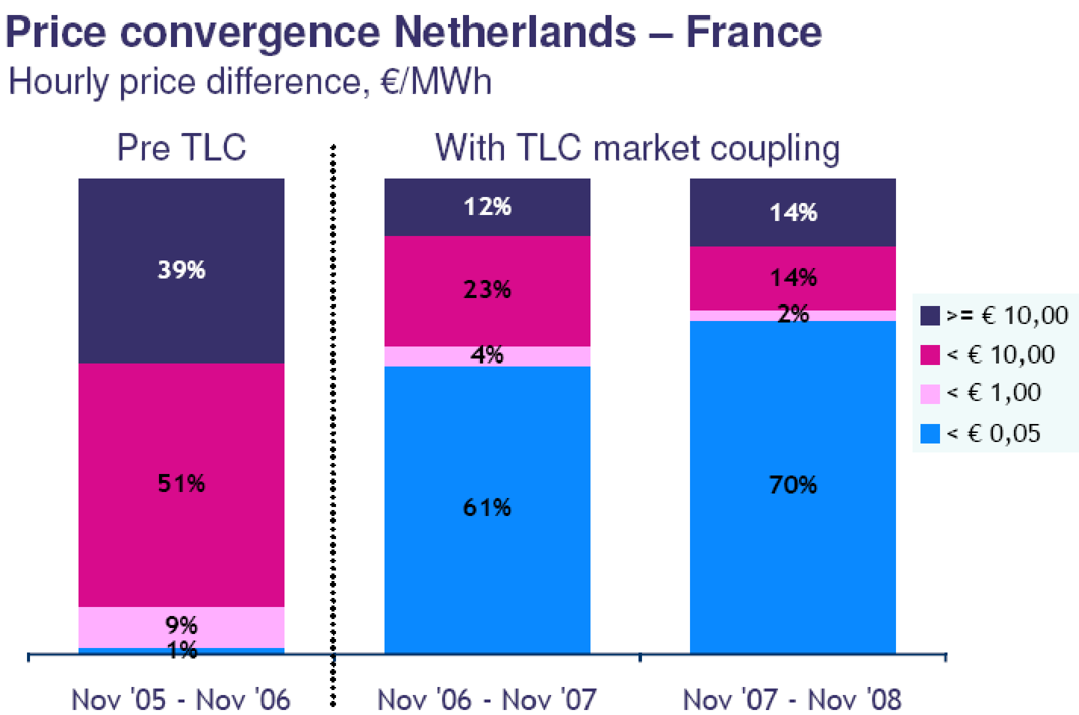


Figure 8.4: Extent of price convergence before and after coupling, NL-FR
Source: Moss (2009)

One measure of the inefficiency of interconnector use before coupling comes from the comparing the price differences and the flows. Figure 8.3 illustrates this for flows between the Netherlands (APX) and France (PowerNext) (Moss, 2009), showing that much of the time the interconnector was underutilised, and for a considerable fraction of the time the power flowed in the wrong direction. After market coupling the price differences between the two countries dramatically narrowed, as shown in Figure 8.4. Before market coupling the prices were within €1/MWh only 10% of the time and were more than €10/MWh apart 39% of the time, but after coupling the prices were within €1/MWh 72% of the time and were more than €10/MWh apart only 14% of the time.

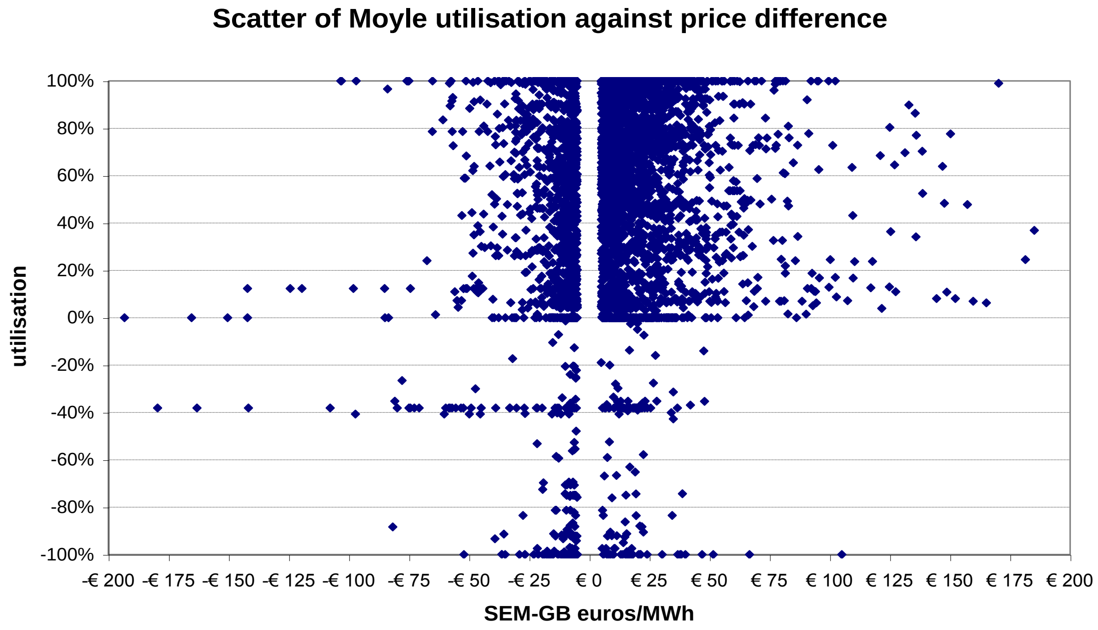


Figure 8.5 Utilisation of the Moyle interconnectors, 2009
Sources: UK prices are UKRPD from APX half hourly, SEM prices from the SEM, flows from Mutualenergy, utilisation taken as measured flow over daily maximum flow, price differences truncated between +/- €25 to +/- €200/MWh

Similar inefficiencies can be observed on other borders. Figure 8.5 shows the utilization of the Moyle interconnector from Scotland to N Ireland (into the Single Electricity Market, SEM) in calendar year 2009, where price differences of less than €25/MWh have been suppressed to avoid over-cluttering the figure. If the price difference is positive and Ireland is importing, then the power is flowing in the right direction (top right sector of figure) although clearly the interconnector is not being fully utilized most of the time. Similarly if price differences are negative and Ireland is exporting, power is again flowing in the right direction (bottom left sector).

If the price difference is positive (SEM prices are above GB prices) and the utilisation is negative (Ireland is exporting) or the price difference is negative and the utilisation is positive (importing), then power is flowing in the wrong direction. About one-third of the time power flows in the wrong direction. This is partly explained by the SEM market prices being determined after dispatch, while the GB prices are "day-ahead" (actually a weighted average of trades up to an hour ahead of dispatch).

ENTSO-E publishes the Net Transfer Capacity (NTC) for interconnectors for summer and winter, and for winter 2010/11 the total NTC capacity between the EU-27 countries was 95 GW. If, improbably, that entire capacity was fully utilised for trade, with an availability of 8,000 hrs. per year, the volume of trade would be 760 TWh. The actual value of international trade in 2011 was 315 TWh, or 40% of the potential. To give a simple estimate of the potential benefit of coupling all of these interconnectors, if utilisation were to be raised to 60% utilisation (i.e. imports and exports were to be increased by 50%) trade would increase by about 160 TWh. If the average of the before and after price differences were €10/MWh then the gain might be €1.6 billion per year.

To put this figure into perspective, the EU27 electricity consumption is about 3,100 TWh and if the average price were €50/MWh the wholesale value would be about €155 bn/yr., so coupling might be worth about 1% on this basis. Clearly this estimate rests on a number of unsubstantiated assumptions (likely trade increase, average price difference before and after price coupling) and so the next step is to firm up this estimate with detailed case studies and other evidence.

8.4 METHODOLOGY FOR MEASURING THE BENEFITS OF COUPLING

Figure 8.6 shows one possible configuration of the interconnector before and after coupling. Volume A is the amount used before coupling with the net supply in the direction of trade and the net demand shown. Market coupling then leads to the full utilization of the interconnector to the volume B, narrowing the price difference as shown. The benefit of coupling is then the green coloured trapezium, on the (competitive market) assumption that the net supply represents the marginal cost (including any scarcity rents) and the net demand represents the willingness to pay for power. In algebraic terms the benefit is the average of the price differences before and after coupling times the increase in the volume of trade or the area of the trapezium DEGH.

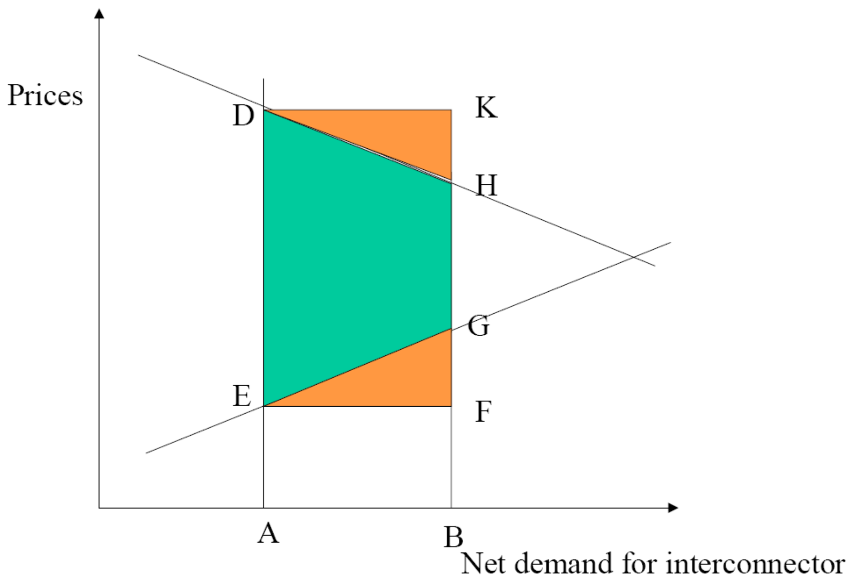


Figure 8.6 Benefits of market coupling when the interconnector remains congested

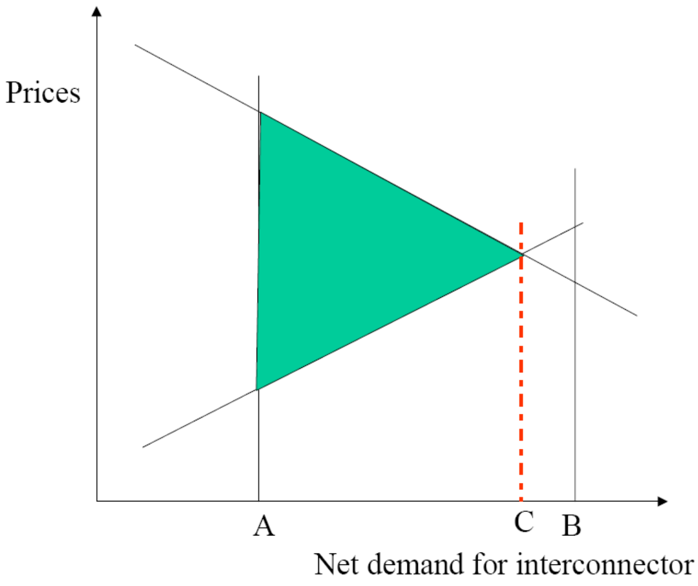


Figure 8.7 Benefits of market coupling when the interconnector becomes uncongested

Figure 8.7 shows the case (evidently common between NL and FR) when market coupling eliminates the price differences in the two markets and the interconnector remains uncongested, with total volume C. In this case the benefit is half the original price difference times AC, the increase in utilisation. Finally figure 8.8 shows the case in which the interconnector is flowing power in the wrong direction. In this case point A corresponds to, say, importing a volume 0A when the efficient coupled solution would be exporting an amount 0C (the capacity of the interconnector is 0B in each direction, although there is no reason why export and import capacity should be the same).

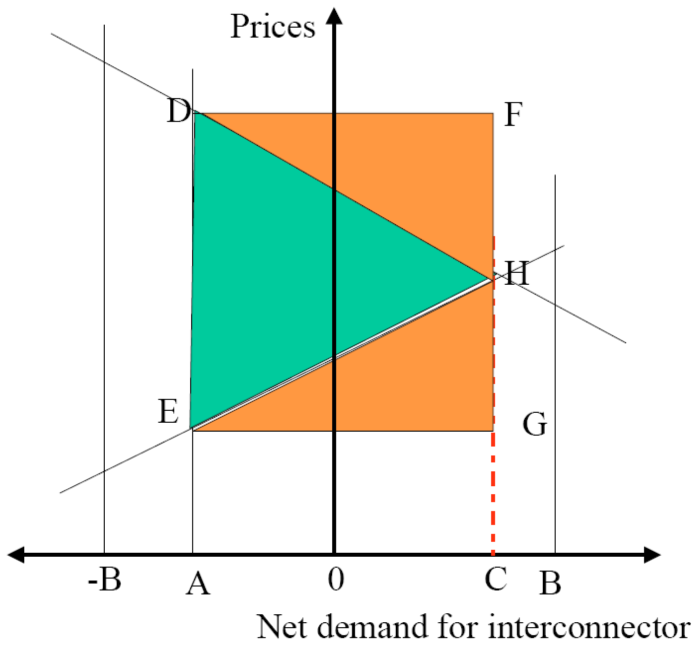


Figure 8.8: Benefits from changing the direction of the power flow

In this case the benefit is half the initial price difference ED times the volume AC, or the area DEH, which is half the area DEGF that assumes prices do not change.

8.5 PRACTICAL CALCULATIONS

The volumes actually used and the price differences at which trade clears are observable for both coupled and uncoupled interconnectors, but unfortunately not the counterfactual of what they would have been had the interconnectors been respectively uncoupled or coupled. Given that there are no sufficiently accurate models that predict market prices (as opposed to, e.g. estimated marginal costs with optimal dispatch in idealised models), some way is needed to construct the counterfactuals. Ideally we would have an estimate of the slopes of net supply and demand in €/MW capacity. If we had no information and if the flows over the interconnectors were small compared to the total market into which they supplied, then a rough assumption would be to assume that prices did not change, so that in figure 8.6, the cost of inefficient use would be measured by the area DEFK, an overstatement of the correct measure DEGH.

In order to gain some rough feel for the sensitivity of price to changes in supply one might examine the offer schedules into power exchanges (or possibly balancing markets in the case of intraday changes in interconnector flows), but this data requires heavy data crunching, and is beyond the scope of this study. Instead an alternative is to examine the relationship between spot prices in GB and levels of supply (actually demand, which is close to supply in percentage terms). There are three possible prompt prices in the GB wholesale electricity market – the original "spot" price, once called UK RPD (reference price data) but now called MIP (Market Index Price), a weighted average of OTC trades close to gate closure, and two auction prices held day ahead for hourly delivery the next day, one coupled to the EU market coupling algorithm for clearing BritNed, and N2EX which is for exactly the same product. Figure 8.9 shows that the price duration curves (PDCs) are fairly similar.

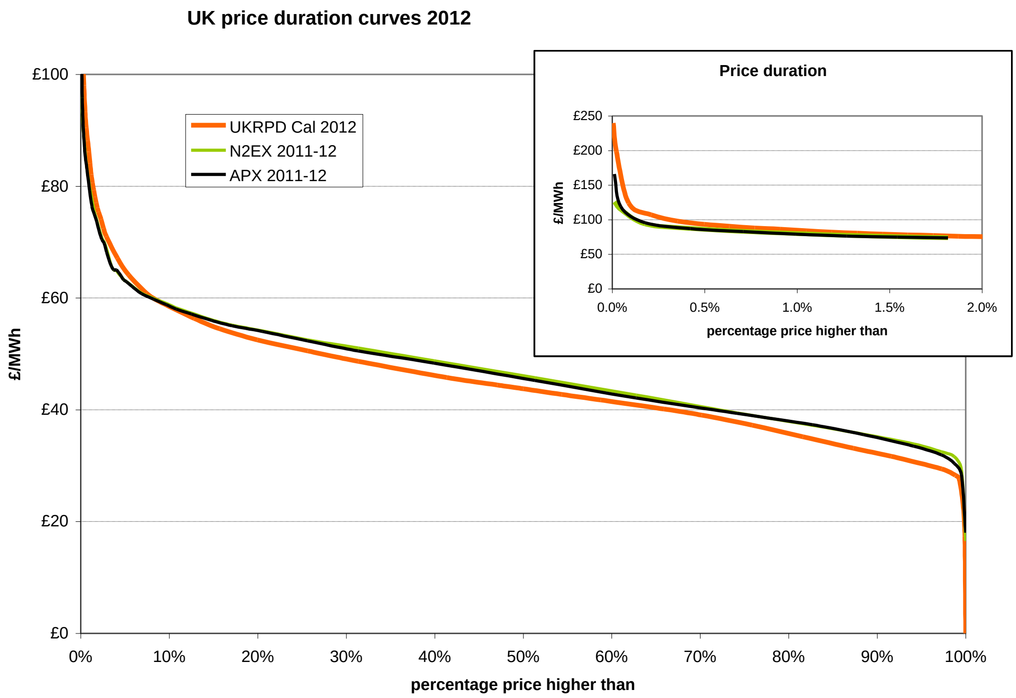


Figure 8.9 Spot prices for UK for recent years

One important feature of all these price curves is that they exhibit a fairly steady decline over the middle 75% of the hours, with most of the extreme variation occurring in the tails – for 2012 the prices change about £20 or €24/MWh going from 20% to 95%.

The next step is to examine the Load Duration Curve (LDC), the counterpart to the PDC, shown in Figure 8.10 where peak demand was about 57GW. The change in load is fairly linear between 10% and 95% of the time, and the change in load is 44% of 57GW over that range, or a change of 25 GW corresponding to the price change of €24/MWh. That suggests a price sensitivity of a little less than €1/MWh per GW change in supply.

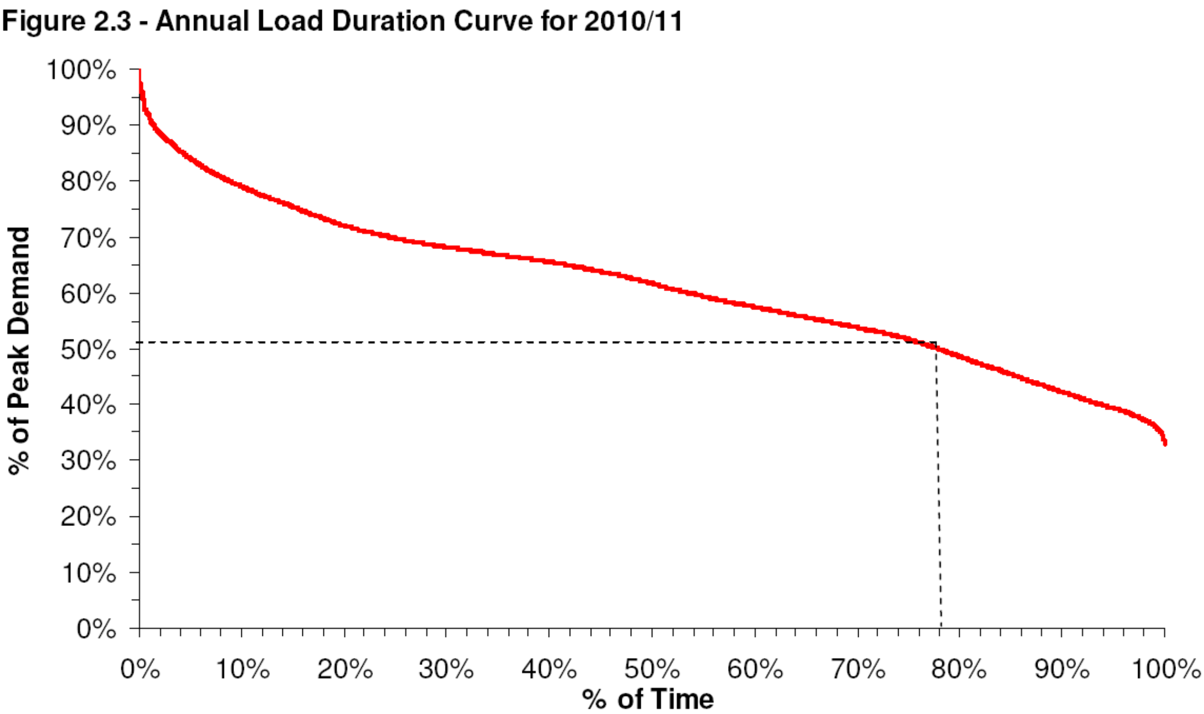


Figure 8.10 The Load Duration Curve for GB for April 2010- March 2011
Source: NGET *2011 NETS Seven Year Statement*

Of course, this price change only applies to changes in GB production, not to changes in French supplies, where the combination of nuclear power, hydro and strong links to other countries would suggest a lower sensitivity, so using €1/MWh per GW change in supply likely overstates the correction to be made as a result of price impacts.

8.6 RESULTS FOR THE ENGLAND FRANCE INTERCONNECTOR (IFA)

If we ignore any impact of changing trade on prices in either country, then it is relatively simple to compute the inefficiencies of under or incorrect utilisation. Tables 1 and 2 give the results for calendar year 2011. The term FAPD is "Flow against price differentials" which occurs when commercial nominations for cross border capacities are such that power flows from a higher price area to a lower price area.

The interpretation is as follows. The potential value of trade in any direction is the price difference (corrected for the losses) times the NTC in that hour and direction. The loss under-exporting is the difference between the actual value of exports and the potential value, for those hours in which the trade flows followed the price difference. In cases of Flows Against Price Differences (FAPD) the flows were in the opposite direction to that signalled by the prices, and the losses reported here are equal to minus the actual value of the trade (which is negative so adds to the potential value) – the rest of the cost is made up of the loss in exports in the correct direction, so arguably part of the cost of FAPD shows up as lost export value.

Note first that a transmission (resistive) loss of 2% reduces the value of potential trade by 10%, with proportionally larger impacts on the losses through inefficient trade, so clearly transmission losses are material, and their proper treatment in coupling not entirely clear, given that the losses are real but seem to be ignored. Next, the potential losses are 24-27% (depending whether or not losses are included) and as such material, and quite large in absolute value at € 22-28 million per year, of which underutilisation is the larger part (but much of that is failing to export when actually importing or vice versa so is arguably a FAPD).

Table 8.1 IFA trade data 2011 *no losses* € m.

Potential value exports FR=>UK	€ 84.0	80%
Potential value exports UK=>FR	€ 20.9	20%
Potential total value trade	€ 104.9	100%
Loss underexport FR=>UK	€ 12.5	12%
Loss underexport UK=>FR	€ 10.8	10%
FAPD FR=>UK	€ 3.2	3%
FAPD UK=>FR	€ 1.5	1%
Total loss	€ 28.1	27%

Table 8.2 IFA trade data 2011 *Losses = 2%* € m.

Potential value exports FR=>UK	€ 77.8	82%
Potential value exports UK=>FR	€ 17.4	18%
Potential total value trade	€ 95.2	100%
Loss underexport FR=>UK	€ 10.3	11%
Loss underexport UK=>FR	€ 8.5	9%
FAPD FR=>UK	€ 2.4	3%
FAPD UK=>FR	€ 1.2	1%
Total loss	€ 22.4	24%

The next two tables repeat this for 2012. In this case transmission losses had a proportionally slightly smaller impact on potential trade (reducing it by 6%), and the trading losses were a lower proportion of potential trade at 14-16%. The differences between 2011 and 2012 are indicative of the annual variability of the value of trade and possibility of more extreme outcomes.

Table 8.3 IFA trade data 2012 *no losses* € m

Potential value exports FR=>UK	€ 115.5	73%
Potential value exports UK=>FR	€ 43.1	27%
Potential total value trade	€ 158.6	100%
Loss underexport FR=>UK	€ 11.9	7%
Loss underexport UK=>FR	€ 6.8	4%
FAPD FR=>UK	€ 3.1	2%
FAPD UK=>FR	€ 3.1	2%
Total loss	€ 24.8	16%

Table 8.4 IFA trade data 2012	Losses = 2%	€ m
Potential value exports FR=>UK	€ 108.7	73%
Potential value exports UK=>FR	€ 40.6	27%
Potential total value trade	€ 149.3	100%
Loss underexport FR=>UK	€ 10.3	7%
Loss underexport UK=>FR	€ 5.5	4%
FAPD FR=>UK	€ 2.4	2%
FAPD UK=>FR	€ 2.7	2%
Total loss	€ 20.8	14%

It is possible to make a rough estimate of the overstatement of these losses as a result of failing to allow for the estimated €1/MWh/GW. In figure 8.6 it is necessary to correct the measured loss DEFK by subtracting the areas DKH and EFG, where the sum of KH and GF is given by the slope €1/MWh/GW and the change AB. This is ½ times the change in volume times the change in price, or equivalently ½ x 1 xAB^2.

In 2011 exports from FR=>UK used 58% of total capacity and from UK=>FR a further 12%, making the overall utilisation of IFA 71%. In 2012 exports from FR=>UK used 74% of total capacity and from UK=>FR a further 10%, making the overall utilisation of IFA 83%. The average NTC in both 2011 and 2012 was roughly 1.25 GW in each direction (i.e. only 63% of its rated capacity), so an underutilisation of 29% in 2011 would be on average is 0.36 GW and the price change might be €0.36/MWh on average over the underutilisation, half that is €0.18/MWh. The extent of underutilisation was 14 TWh so the overstatement is €2.5 million, reducing the total 2011 losses from €23.6 million to €21.1 million or by 10% (so not insignificant). In 2012 the underutilisation was 12.7 TWh so the overstatement was €2.3 million, reducing the total 2012 losses from €75.1 million to €72.8 million or by only 3%, proportionately rather less significant. The error in ignoring price impacts increases as the *square* of the shortfall and so becomes smaller as interconnectors are more fully used.

8.7 RESULTS FOR FRANCE GERMANY INTERCONNECTION 2010

It is also possible to estimate the inefficiency of the France-Germany interconnector for the year 2010, although as this interconnector was coupled in November 2010 and as reliable NTC data is only available from September 2010, there is relatively little reliable data available for the pre-coupling case. Nevertheless, the example is useful as it can be compared with the reports presented in the *Quarterly Report on European Electricity Markets* (QREEM), which gives similar information for other interconnectors. From Q3, 2010, the QREEM started publishing data on 'flow against price differentials' (FAPD), just before the markets of Central West Europe were coupled on the 9th of November 2010 (and after which FAPDs should, and mostly were, zero, at least according to QREEM). If the data for FAPDs from QREEM can be validated against a detailed analysis for one of the interconnectors then it might be possible to extrapolate the results to a wider set of countries.

To quote from QREEM 2010 Q4:

> "An event named 'flow against price differentials' (FAPD) occurs when commercial nominations for cross border capacities are such that power is set to flow from a higher price area to a lower price area. The FAPD chart provides detailed

information on adverse flows. It has two panels. The first panel estimates the ratio of the number of hours with adverse flows to the number of total trading hours in a quarter. It also estimates the monetary value of energy exchanged in adverse flow regime compared to the total value of energy exchanged across the border. The monetary value of energy exchanged in adverse flow regime is also referred to as "welfare loss". A colour code informs about the relative size of FAPD hours in the observed sample, going from green if less than 10% of traded hours in a given quarter are FAPDs to red if more than 50% of the hours are FAPDs. The second panel gives the split of FAPDs by subcategory of pre-established intervals of price differentials. It represents the average exchanged energy and relative importance of each subcategory on two vertical axes."

One important border for which the pre-coupling FAPDs can be roughly measured was that between France and Germany, for which we have reasonably complete data. This example is shown in Figure 8.11 for Q4 2010. To again quote from QREEM 2010 Q4 for this case:

> "505 events of FAPD were observed in Q3 2010, representing 34.5% of the total number of traded hours. The ratio of the volume of adverse flows compared to all cross border flows was 29.2%. The welfare loss, which can be calculated from the net adverse flow volumes and the price differentials between the two markets, was €2.13 million in Q3 2010. The total value of cross border flow price mark-ups was €17.3 million." (QREEM Q3 2010)'

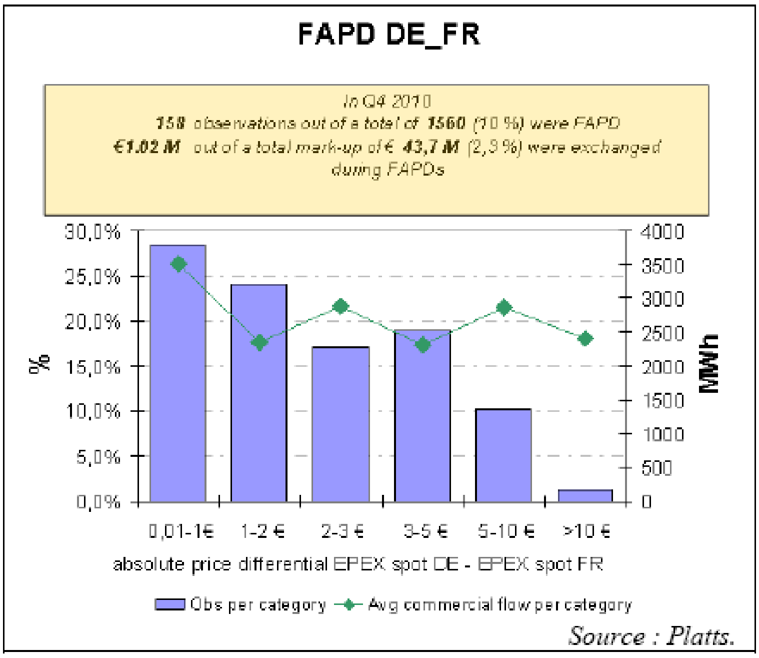


Figure 8.11 Flow against price differentials between Germany and France, Oct-Dec 2010
Source: *Quarterly Report on European Electricity Markets 2010 Q4*

> "The ratio of FAPDs between the German and French markets out of the total observations was lower (10%) than in Q3 2010 (34%). The ratio of FAPDs between Germany and the Netherlands (43%) did not show a remarkable change compared to the third quarter of 2010. After the market coupling took place on the 9th of November 2010, adverse power flows could not be observed either between Germany and France or between Germany and the Netherlands." (QREEM Q4 2010)

Thus in Q3, 2010 the estimated welfare cost of the FAPD on the DE-FR interconnector was €2.3 million – the flows were mostly larger except at high price differences. The value of welfare loss compared to trade was 12% for DE-FR (compared with 38% for NL-DE).

Successive issues of QUEEM give rather patchy information of the value of adverse flows from which it is possible to construct Table 8.5 below. Italicised numbers indicate that the values are taken from the graphs of the share of FAPDs, which are only a rough guide to their value, as that will depend on the distribution of the shares over price differences. The consistent totals are for the rows that reappear in all years after Q4 2010, not for all entries, and the blanks are not reported. Note that GB-FR is interconnected but not reported, nor is the Moyle (which does not apparently count as an interconnector as it lies entirely within the UK). The numbers are given to only one significant figure, as they are estimates in several senses, both in not recording underutilisation, nor in properly comparing against the counterfactual of market coupling, and finally as figures derived from graphs rely on consistency in the relation of costs to FAPD frequency. According to table 8.5 (and figure 8.11) FAPDs for DE-FR accounted for just over €1 million in Q4 2010, and actual trade was €44 million.

Table 8.5 Values of adverse flows *Millions of Euros*

	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Q4 2011	Q1 2012	Q2 2012
NL-DE	2.1	1.8	0.003	0	0	0	0	0
BE-NL	0	0	1.8	0	0	0	0	0
BE-FR	0	0	0.01	0	0	0	0	0
FR-DE	2.3	1	0.02	0	0	0	0	0
DK-NO_W		0.44						
IT-FR		2.8	0.9	0.3	0.01	0.2	1.3	0.1
AT-IT			0.05	0.01	0.0002	0.003	0.003	0.01
IT-SI								0.1
IT-GR								0.8
ES-FR		0.1	0.4	0.3	0.3	0.3	0.55	0.27
ES-PO								0.02
CZ-SK		0	0	0	0	0	0	0
DE-PL			0.05	0.17	*italics indicate estimates based on graphs*			
DE-CZ		*2.1*	2.1	4.2	*4*	*2*	*4*	*4*
CZ-PL				0.1				
AT-CZ		*0.5*	*0.5*	0.6	0.6	*0.6*	*0.6*	*0.6*
AT-HU		*0.2*	0.2	0.7	0.7	*0.2*	*0.7*	*0.7*
SK-HU		*1.1*	1.1	3.4	2	*1*	*1*	*2*
SK-PL			0.1	0.1				
Totals consistent		9.6	7.08	9.51	7.61	4.30	8.13	7.68

Source: *QREEM*, various issues
Note: Yellowed entries indicate a degree of estimation or interpolation

It would clearly be desirable to examine a period of trade before coupling, as the aim is to measure the impact of the Third Package and market coupling in particular. This is complicated by the lack of hourly NTC data for the period before mid-September 2010, and table 8.6 attempts to circumvent this by using the latest NTCs for Sep-10, and taking the maximum of these numbers or the actual flows before that date. The actual NTCs for comparable months in 2011 are also shown, and the implied utilisations using the actual flows for 2010 and either the presumed 2010 flows, or the actual 2011 flows. There is no obvious pattern of differences to they may provide a very rough estimate of the losses from not coupling in 2010.

Table 8.6 Actual flows and estimated NTCs, DE-FR, 2010 (actual NTCs for Sep-Dec)

averages	Flows 2010		NTCs est.	NTCs 2010	utilisation based on estimates			NTCs 2011		utilisation 2010 flows 2011 NTCs	
Months	FR>DE	DE>FR	FR>DE	DE>FR	FR>DE	DE>FR		FR>DE	DE>FR	FR>DE	DE>FR
Jan-10	47	2440	***1803***	***2715***	***2%***	***88%***	Jan-11	2804	2985	2%	84%
Feb-10	299	1765	***1875***	***2500***	***12%***	***67%***	Feb-11	2796	2714	11%	89%
Mar-10	645	1150	***2014***	***2271***	***24%***	***49%***	Mar-11	2763	2981	24%	39%
Apr-10	520	1047	***1948***	***2245***	***21%***	***46%***	Apr-11	2279	2717	23%	38%
May-10	606	1064	***2028***	***2227***	***21%***	***47%***	May-11	2137	2445	29%	44%
Jun-10	2105	253	***2770***	***2211***	***63%***	***11%***	Jun-11	1983	2200	107%	12%
Jul-10	1657	439	***2510***	***2216***	***53%***	***19%***	Jul-11	1972	2746	84%	16%
Aug-10	3298	65	***3551***	***2200***	***86%***	***3%***	Aug-11	1884	2768	174%	2%
Sep-10	914	551	1803	2221	37%	25%	Sep-11	1505	2588	58%	21%
Oct-10	445	1734	2590	3231	17%	57%	Oct-11	1800	2757	25%	64%
Nov-10	459	1448	2597	3060	17%	49%	Nov-11	1800	2461	25%	61%
Dec-10	23	2275	2647	2932	1%	78%	Dec-11	1800	1756	1%	133%
Year 2010	918	1186	2003	2420	30%	45%	Year 2011	2127	2593	47%	50%

Note: Yellowed entries indicate a degree of estimation or interpolation

With these estimates for the NTCs it is possible to calculate the losses on the DE-FR interconnectors for 2010, and these are shown in Table 8.7.

Table 8.7 Estimated losses and trade, Q1 2010-Q3, and actuals for Q4 2010 ***€Millions***

Quarters	loss FR not exporting enough	Loss DE not exporting enough	FAPD FR	FAPD DE	total loss	actual trade	Potential trade
Q1 2010	€ 1.60	€ 2.59	€ 0.53	€ 0.88	€ 5.61	€ 43.88	€ 48.08
Q2 2010	€ 2.08	€ 4.97	€ 2.18	€ 0.97	€ 10.19	€ 14.85	€ 21.89
Q3 2010	€ 1.47	€ 4.41	€ 2.68	€ 0.46	€ 9.02	€ 20.02	€ 25.90
Q4 2010	€ 1.68	€ 3.34	€ 0.16	€ 0.66	€ 5.84	€ 36.87	€ 41.89
Year	€ 6.82	€ 15.31	€ 5.55	€ 2.97	€ 30.65	€ 115.62	€ 137.75

The FAPD certainly drops dramatically with coupling in Q4, although not to zero as coupling came half way through the quarter. We can also compare these estimates with those in Table 8.5. The figures for FAPDs for Q3 and Q4 in total are comparable to table 8.5, although the measured trade in Q4 at €37 million is somewhat below that in Figure 8.11 of

€44 million. Total losses for the year are 22% of potential trade or 26% of measured trade, and this falls to 16% in Q4. For the first 3 quarters the losses are 31% of measured trade or 26% of potential trade. Note we assume no transmission losses over the interconnectors as they are part of the meshed grid, and the borders are infinitely thin.

8.8 ASSESSMENT OF THE EVIDENCE ON INEFFICIENCIES OF CROSS-BORDER TRADE

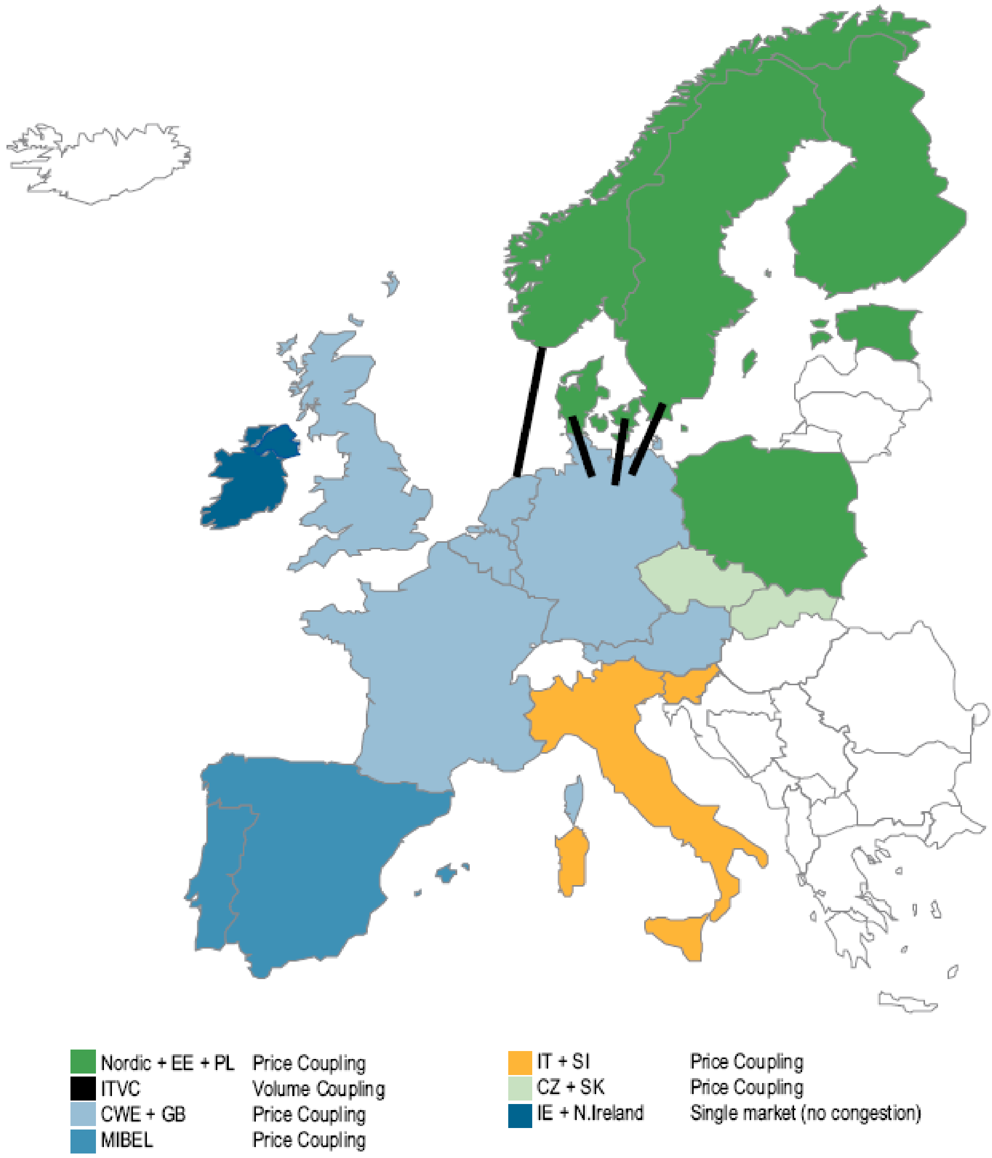


Figure 8.12 Market coupling in Europe 2011
Source: ACER (2012, figure 16).

One measure of the inefficiency of interconnector use before coupling comes from the comparing the price differences and the flows. Figure 8.3 illustrates this for flows between the Netherlands (APX) and France (PowerNext) (Moss, 2009), showing that much of the time the interconnector was underutilised, and for a considerable fraction of the time the power flowed in the wrong direction. After market coupling the price differences between the two countries dramatically narrowed, as shown in Figure 8.4. Before market coupling the prices were within €1/MWh only 10% of the time and were more than €10/MWh apart 39% of the time, but after coupling the prices were within €1/MWh 72% of the time and were more than €10/MWh apart only 14% of the time.

ACER (2012) claims that "The convergence of wholesale electricity prices can be regarded as an indicator of market integration. ... During the period 2005-2011, the Dutch, Belgian, French and German spot prices clearly showed signs of convergence. The Nordic system price followed a similar trend; however, the actual price was usually lower due to the limited transmission capacity in the Central West Europe (CWE) region. Additionally, low reservoir levels could quickly shift the Nordic price closer to, or even push it above, the Continental price levels (as in 2010)." Figure 8.1 above shows time series of PX prices over longer periods of time, but a better measure of the impact of market coupling is to compare absolute price differences between trading countries before and after market coupling, and to examine the percentage of time that the exchanges showed no price differences (from coupling in the absence of congestion), or small differences (which is better for comparing before and after). The next few tables give the averages of the absolute price differences from Germany (EEX) as that is a centrally placed country for many interconnectors.

It is clear that prices converged for Germany, France and the Netherlands in 2011, but not for the other links (except to Denmark, for which data for 2010 was not readily available). Nevertheless, Hungary shows a sharp move towards neighbouring prices in 2011.

Table 8.8 Absolute values of price differences from EEX, 2010 *Euros/MWh*

averages	NL	FR	CH	PL	CZ	HU
Jan-10	€ 4.12	€ 10.83	€ 13.01	€ 7.79	€ 7.62	€ 42.24
Feb-10	€ 3.21	€ 6.82	€ 15.26	€ 6.60	€ 4.57	€ 41.76
Mar-10	€ 3.60	€ 7.53	€ 19.41	*€ 8.41*	€ 4.59	€ 39.21
Apr-10	€ 3.26	€ 3.51	€ 9.08	€ 7.08	€ 5.91	€ 40.04
May-10	€ 3.56	€ 3.95	€ 3.88	€ 8.29	€ 5.49	€ 41.17
Jun-10	€ 3.69	€ 4.11	€ 3.67	€ 6.70	€ 5.82	€ 43.33
Jul-10	€ 2.91	€ 2.83	€ 2.72	€ 5.19	€ 4.59	€ 33.17
Aug-10	€ 2.75	€ 4.48	€ 2.95	€ 8.46	€ 4.41	€ 41.54
Sep-10	€ 3.33	€ 3.71	€ 3.86	€ 6.44	€ 5.31	€ 5.21
Oct-10	€ 3.36	€ 9.08	€ 10.02	€ 5.32	€ 6.69	€ 6.38
Nov-10	€ 1.12	€ 3.17	€ 8.56	€ 5.60	€ 4.12	€ 6.64
Dec-10	€ 3.47	€ 7.22	€ 9.30	€ 10.28	€ 7.19	€ 10.95
Year 2010	€ 3.20	€ 5.60	€ 8.48	€ 7.18	€ 5.53	€ 29.30

Note: Yellowed entries indicate a degree of estimation or interpolation

Table 8.9 Absolute values of price differences from EEX, 2011 *Euros/MWh*

averages	NL	FR	CH	DK1	DK2	PL	CZ	HU
Jan-11	€ 1.44	€ 1.84	€ 7.90	€ 3.26	€ 4.76	€ 8.71	€ 5.36	€ 5.86
Feb-11	€ 2.50	€ 3.05	€ 10.71	€ 1.14	€ 1.57	€ 8.06	€ 3.72	€ 5.21
Mar-11	€ 1.08	€ 2.46	€ 7.29	€ 1.15	€ 1.27	€ 5.78	€ 3.77	
Apr-11	€ 1.66	€ 2.32	€ 4.20	€ 2.78	€ 2.88	€ 4.61	€ 3.27	€ 4.77
May-11	€ 0.32	€ 3.31	€ 3.66	€ 6.62	€ 6.39	€ 6.58	€ 3.44	€ 5.34
Jun-11	€ 0.84	€ 9.18	€ 3.39	€ 1.81	€ 1.46	€ 5.74	€ 3.56	€ 4.98
Jul-11	€ 0.39	€ 9.15	€ 3.13	€ 4.24	€ 3.23	€ 6.64	€ 3.65	€ 10.68
Aug-11	€ 0.78	€ 7.59	€ 2.71	€ 3.48	€ 3.43	€ 5.63	€ 2.92	€ 9.14
Sep-11	€ 0.46	€ 2.78	€ 3.15	€ 4.96	€ 4.40	€ 8.81	€ 4.04	€ 13.78
Oct-11	€ 0.35	€ 1.21	€ 6.09	€ 9.03	€ 5.63	€ 8.48	€ 4.99	€ 7.23
Nov-11	€ 0.69	€ 1.52	€ 12.50	€ 9.94	€ 5.48	€ 7.28	€ 3.47	€ 12.46
Dec-11	€ 2.80	€ 3.05	€ 17.49	€ 9.33	€ 8.81	€ 6.76	€ 5.52	€ 16.47
Year	€ 1.10	€ 3.96	€ 6.83	€ 4.84	€ 4.14	€ 6.92	€ 3.98	€ 8.72

The next two tables give the proportion of the time that absolute price differences were less than some critical value. Table 8.10 shows that prices were closer than €2.5/MWh apart for about half the time between Germany and the Netherlands and France in 2010, while in 2011 this rose to 93% (in the case of The Netherlands) and about three-quarters for France. Denmark was also close in 2011. The other borders showed no obvious trends.

Table 8.10 Percentage of hours in which price differences with EEX were less than €2.5/MWh

	NL	FR	CH	PL	CZ	HU
Jan-10	42%	27%	13%	24%	30%	0%
Feb-10	51%	37%	5%	28%	38%	1%
Mar-10	44%	36%	6%		39%	0%
Apr-10	53%	51%	23%	26%	34%	0%
May-10	51%	47%	44%	26%	37%	1%
Jun-10	43%	40%	46%	29%	29%	1%
Jul-10	62%	60%	57%	35%	35%	13%
Aug-10	61%	51%	57%	27%	41%	38%
Sep-10	52%	51%	45%	32%	38%	42%
Oct-10	54%	37%	20%	38%	32%	34%
Nov-10	84%	66%	21%	35%	50%	32%
Dec-10	75%	51%	22%	19%	29%	23%
Year 2010	56%	46%	30%	29%	36%	16%

Table 8.11 Percentage of hours in which price differences with EEX were less than €2.5/MWh

	NL	FR	CH	DK1	DK2	PL	CZ	HU
Jan-11	88%	84%	22%	70%	64%	18%	40%	36%
Feb-11	86%	81%	17%	89%	83%	25%	54%	41%
Mar-11	93%	78%	24%	85%	83%	29%	49%	
Apr-11	89%	79%	46%	73%	72%	44%	52%	42%
May-11	97%	71%	47%	37%	38%	37%	49%	39%
Jun-11	95%	51%	53%	84%	87%	42%	51%	43%
Jul-11	96%	54%	52%	53%	63%	27%	48%	35%
Aug-11	94%	59%	57%	62%	76%	29%	57%	44%
Sep-11	96%	78%	54%	66%	69%	23%	49%	33%
Oct-11	96%	87%	33%	42%	64%	22%	36%	32%
Nov-11	93%	86%	14%	30%	53%	25%	50%	34%
Dec-11	77%	73%	8%	25%	26%	20%	34%	18%
Year	92%	73%	36%	59%	65%	28%	47%	36%

We can investigate the effect of market coupling further by examining the proportion of the time the borders were uncongested (with a zero price difference), and table 8.12 shows this to be high for The Netherlands, and not zero for France and Denmark, but zero for all the other links, showing that there were hours of uncongested flow in the former cases, but much of the time, although price differences were small, the links were presumably fully used (as they were coupled and prices differed.

Table 8.12 Percentage of hours in which price differences with EEX were zero (uncongested)

	NL	FR	CH	DK1	DK2	PL	CZ	HU
Jan-11	83%	15%	0%	13%	12%	0%	0%	0%
Feb-11	82%	14%	0%	18%	16%	0%	0%	0%
Mar-11	89%	13%	0%	18%	18%	0%	0%	
Apr-11	85%	18%	0%	19%	18%	0%	0%	0%
May-11	94%	15%	0%	7%	8%	0%	0%	0%
Jun-11	92%	9%	0%	23%	24%	0%	0%	0%
Jul-11	93%	12%	0%	14%	16%	0%	0%	0%
Aug-11	91%	13%	0%	13%	15%	0%	0%	0%
Sep-11	94%	19%	0%	11%	11%	0%	0%	0%
Oct-11	93%	23%	0%	8%	11%	0%	0%	0%
Nov-11	92%	22%	0%	10%	12%	0%	0%	0%
Dec-11	72%	15%	0%	6%	6%	0%	0%	0%
Year	88%	16%	0%	13%	14%	0%	0%	0%

Another step in this exercise would be to compare some of these price differences in previous years (which is possible for DE, NL, and FR, as well as FR-ES, and possibly also IT-DE) and to estimate the extent of capacity utilisation on the links, although a preliminary test for DE shows that some of the flows appear to exceed reported NTCs. Given the price differences in the past, Δp_0, and an estimate of the extent of underutilisation (say M MW), and the current price difference, Δp_1, the gains from better integration would be $\frac{1}{2}(\Delta p_0 + \Delta p_1)M$.

Figure 8.2 above and figure 8.14 below shows the kind of information available on price differences from 2003-2012. They show that trade between Germany, France and Netherlands (and particularly Germany-Netherlands) was converging from Jan 2009 from €100,000/MW/yr to less than €50,000/MW/yr (i.e. from €11/MWh to €6/MWh), presumably in part because of better cross-border capacity utilisation. Although France and UK are linked by 2 GW (and indirectly through Britned since April 2011 with a further 1 GW) price differences remain high, as only Britned is coupled, and then not to the reference price used in this study (RPD) but to the new hourly APX auction, which is far closer aligned to the Continental prices. France and Spain are not yet coupled and price differences show no obvious tendency to decrease.

Figure 8.12 shows that France was exporting almost all the time to Germany during this period but the volume was decreasing until 2009 after which it increased, consistent with better use of interconnectors (data for Switzerland is lacking for 2011).

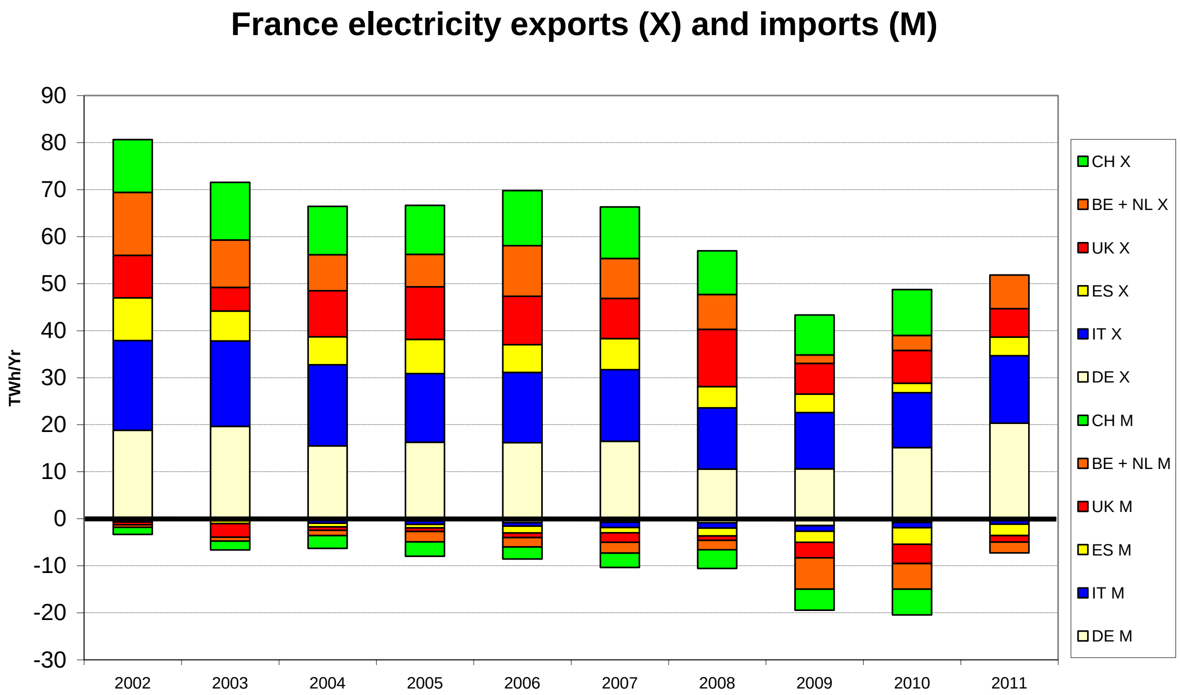


Figure 8.12 Volume of French exports (positive) and imports (negative)

Figure 8.12 shows that French exports to Spain fell in 2010 (and imports rose) and Figure 8.13 shows more clearly how intensively the interconnectors were used – total exports plus imports fell slightly (and were only 59% of their 2002 value). Given the high scarcity value of interconnection with Spain this suggests considerable inefficiency through a failure to couple the markets, although this would require more careful study to see whether there were many hours when price differences were negligible.

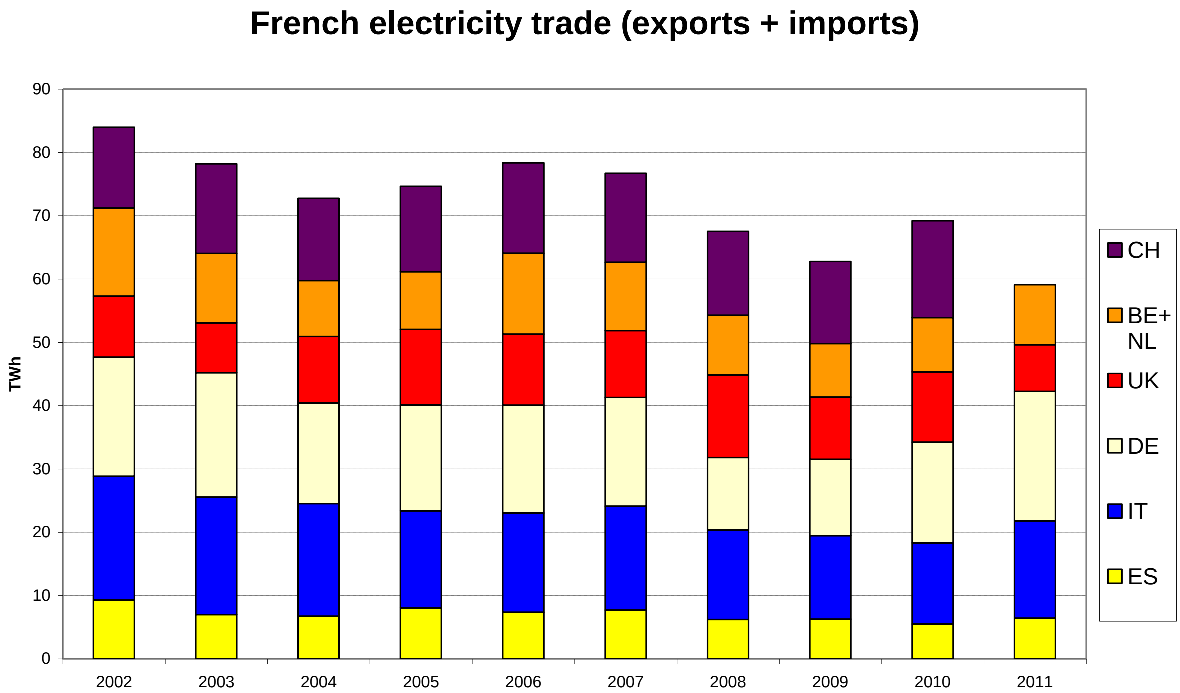


Figure 8.13 Total trade with France

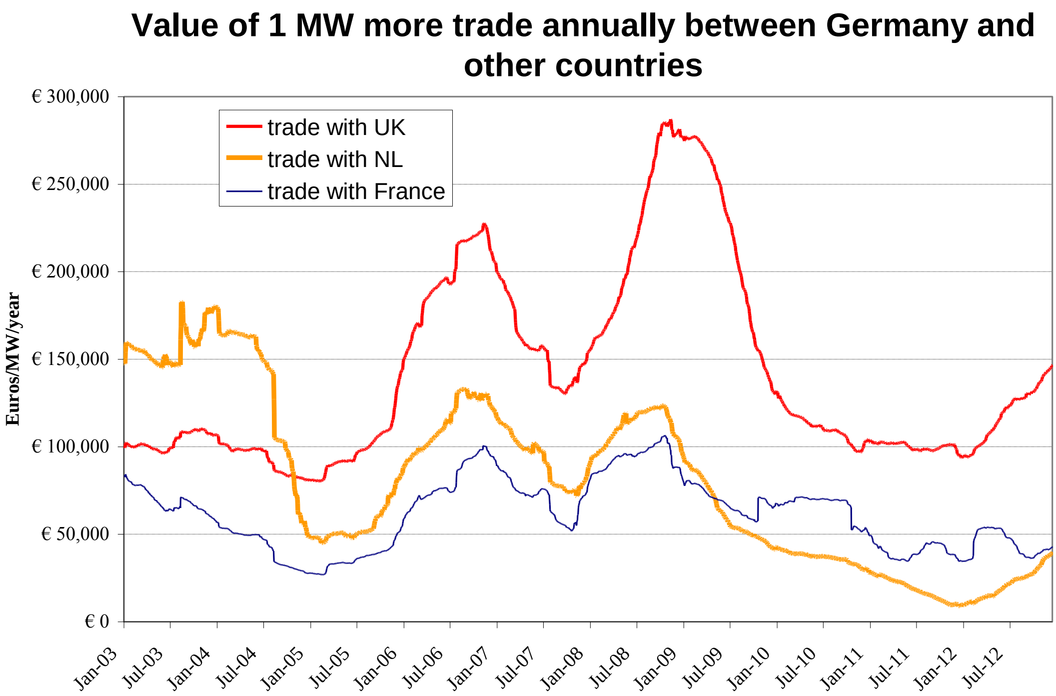


Figure 8.14 Annual value of releasing 1 MW more cross-border capacity from Germany

Figure 8.14 shows that coupling seems to be having the desired convergence effect between Germany and France and The Netherlands. Trade has increased since 2009, but has not returned to their 2006 level. Note that Germany cannot trade with the UK so the price differences there are a measure of the difference across countries, not the potential for trade (except indirectly through NL and FR).

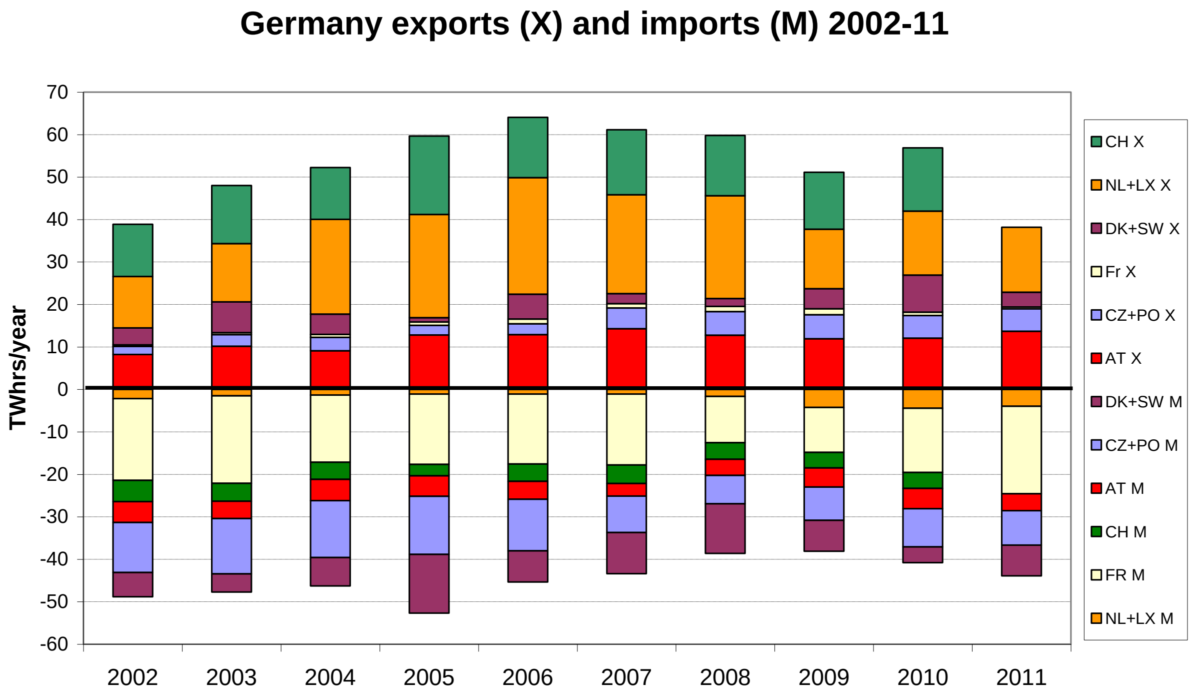


Figure 8.15 Volume of German exports (positive) and imports (negative)

Figure 8.15 gives shows that Germany was exporting quite heavily to the Netherlands but this fell somewhat after 2009 (data for Switzerland is lacking for 2011). Given that Germany was heavily importing from France, and that the Netherlands was coupled earlier with France, the fall in exports is understandable, but it does complicate calculating the benefits of integration in any simple aggregated way (rather than looking at detailed flows, NTCs, and prices over each link. The next section suggests that the flow and NTC data are not necessarily very reliable.

Figure 8.16 shows that coupling seems to be having the desired convergence effect with France and the Netherlands and trade has increased since 2009, but they have not returned to their 2006 level.

Another measure of the efficiency or otherwise of market integration is the extent to which the cross-border links are utilized, particularly pre-coupling when prices differed across borders hourly almost all the time. Unfortunately we do not have NTC data for many months pre-coupling in CWE (only 2 months from mid-September 2010). Other links were however not coupled in 2011 and give some sense of differences between coupled and uncoupled links.

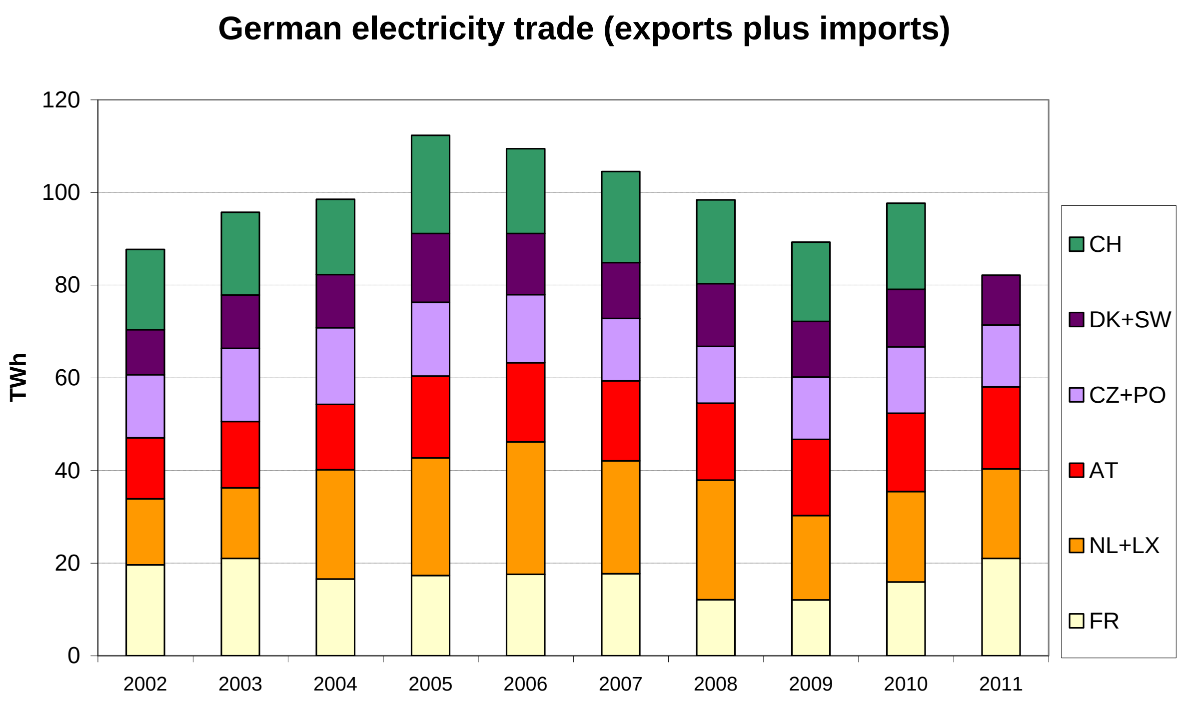


Figure 8.16 Total trade with Germany

8.9 Capacity utilization of cross-border links

Table 8.13 Capacity Utilization and NTCs for various links, 2011

averages	FR-BE	FR-DE	FR-IT	FR-ES	FR-CH	FR-UK
Jan-11	31%	81%	88%	69%	89%	72%
Feb-11	35%	62%	96%	27%	91%	71%
Mar-11	40%	95%	94%	34%	94%	71%
Apr-11	33%	108%	98%	69%	95%	74%
May-11	26%	121%	98%	69%	96%	75%
Jun-11	50%	138%	100%	85%	99%	83%
Jul-11	40%	132%	100%	85%	98%	88%
Aug-11	26%	131%	100%	86%	94%	86%
Sep-11	30%	151%	100%	87%	92%	80%
Oct-11	21%	105%	93%	86%	85%	69%
Nov-11	25%	117%	95%	69%	91%	53%
Dec-11	29%	115%	93%	80%	92%	72%
Year	33%	120%	96%	80%	93%	76%
Max	100%	203%	165%	142%	100%	122%
NTC	FR-BE	FR-DE	FR-IT	FR-ES	FR-CH	FR-UK
Avg	2,880	2,116	1,926	948	3,116	1,241
Max	3,700	4,000	2,650	1,400	3,200	2,000

DG-ENER has compiled data on commercial schedules and NTCs of a number of cross-border links since 19 Sep 2010, and the tables below give the capacity utilization (measured as scheduled flow divided by NTC) for a number of these for 2011. Unfortunately, the tables reveal an obvious problem with the data as the maximum value in any hour should not exceed 100% but it clearly does in several cases.

Although FR-BE and FR-DE were coupled in 2011, the remaining columns describe uncoupled links. Perhaps surprisingly the coupled links were less heavily used, but that indicates that prices had converged and eliminated congestion.

Table 8.14 Capacity Utilization and NTCs for various links, 2011

averages	DE-FR	DE-NL	DE-CH	DE-DKW	HU-AT
Jan-11	108%	155%	168%	78%	52%
Feb-11	99%	124%	181%	58%	37%
Mar-11	96%	108%	159%	60%	57%
Apr-11	72%	109%	140%	65%	41%
May-11	42%	60%	58%	86%	38%
Jun-11	68%	115%	49%	40%	38%
Jul-11	57%	102%	44%	47%	13%
Aug-11	42%	92%	57%	41%	19%
Sep-11	83%	94%	18%	36%	18%
Oct-11	117%	93%	131%	45%	25%
Nov-11	97%	99%	175%	53%	16%
Dec-11	155%	135%	178%	73%	12%
Year	102%	111%	139%	65%	42%
Max	200%	203%	330%	194%	100%
NTCs					
Avg	2,593	2,313	1,097	750	785
Max	3,651	2,449	1,461	2,800	1,000

Similarly, DE-FR, DE-NL and DE DKW were coupled in 2011 but HU-AT was not and relatively underused, given the significant price differences recorded in Table 8.9 (assuming DE and AT had similar prices) although Table 8.10 shows rapid convergence from July 2010.

Table 8.15 Capacity Utilization and NTCs for various links, 2011

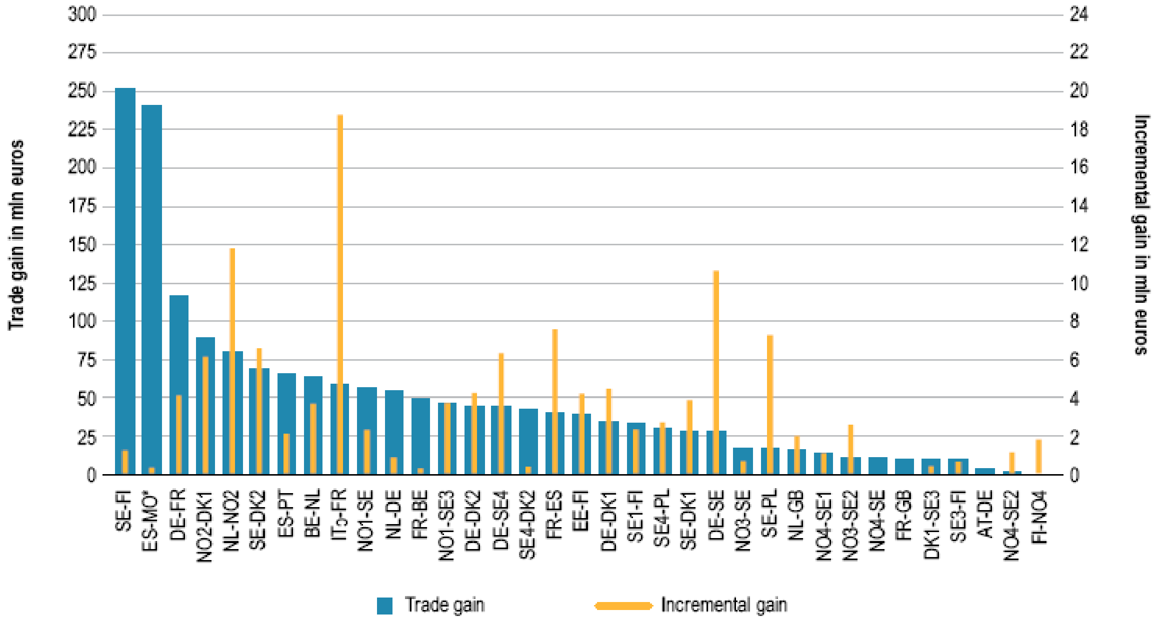
averages	NL-BE	NL-DE	NL-UK	ES-FR	ES-PT
Jan-11	53%	9%		89%	62%
Feb-11	53%	16%		77%	33%
Mar-11	64%	38%		89%	55%
Apr-11	46%	67%	46%	86%	52%
May-11	19%	91%	47%	90%	30%
Jun-11	10%	74%	61%	84%	36%
Jul-11	6%	64%	68%	75%	41%
Aug-11	13%	81%	67%	74%	38%
Sep-11	25%	82%	52%	64%	39%
Oct-11	56%	69%	50%	74%	37%
Nov-11	51%	87%	44%	90%	33%
Dec-11	61%	78%	71%	66%	43%
Year	53%	75%	58%	83%	42%
Max	100%	202%	129%	115%	170%
NTC	NL-BE	NL-DE	NL-UK	ES-FR	ES-PT
Avg	1,370	2,292	914	571	1,912
Max	1,401	2,449	1,016	1,100	2,400

Table 8.16 Capacity Utilization and NTCs for various links, 2011

averages	AT-HU	AT-IT	AT-SL	AT-CH	BE-FR	BE-NL	CZ-AT	CZ-DE
Jan-11	22%	99%	20%	94%	21%	49%	78%	128%
Feb-11	28%	100%	42%	99%	23%	38%	63%	99%
Mar-11	28%	98%	46%	94%	19%	55%	67%	114%
Apr-11	22%	98%	31%	68%	18%	72%	63%	107%
May-11	20%	98%	41%	45%	23%	69%	66%	113%
Jun-11	28%	99%	39%	42%	21%	85%	51%	101%
Jul-11	70%	100%	77%	46%	30%	83%	36%	58%
Aug-11	59%	99%	70%	55%	21%	78%	41%	57%
Sep-11	79%	100%	92%	44%	27%	64%	53%	97%
Oct-11	63%	100%	77%	84%	32%	47%	63%	119%
Nov-11	77%	100%	88%	96%	34%	53%	58%	97%
Dec-11	75%	101%	91%	97%	33%	58%	72%	97%
Year	61%	99%	65%	77%	29%	68%	60%	100%
Max	100%	105%	100%	164%	100%	100%	104%	251%
NTC	AT-HU	AT-IT	AT-SL	AT-CH	BE-FR	BE-NL	CZ-AT	CZ-DE
Avg	749	171	855	312	1,420	1,370	772	2,208
Max	1,000	220	902	900	2,000	1,401	800	2,850

Spain and Portugal were coupled through MIBEL and utilisation is low, as the links were uncongested 92% of the time in 2011,[38] and transmission was expanded as part of the MIBEL project. High utilisation between ES-FR indicates the high value of trade indicated in Figure 8.2, and coupling may not reduce losses as much as elsewhere (but that could be checked).

ACER (2012) gives an interesting simulation study of the gross welfare benefits of cross-border trade, shown in figure 8.17.



Source: PCR project, including APX-Endex, Epex Spot, Nordpool, GME, OMIE (2012)

*Note: * refers to Morocco. ↄ indicates that the zone is a GME zone.*

Figure 8.17 Simulation results: gross welfare benefits from cross-border trade and incremental gain per border – 2011 (millions of euro per year)
Source: ACER (2012, figure 26, p68)

> "[Figure 8.17] shows the welfare gain from trade (that is "Welfare Trade Gain") by border for 2011, in millions of euros. This is the difference between the simulated gross welfare benefit stemming from the Zero scenario and the Historical scenario.[39] The figure also shows the so-called "Incremental Gain", which is the difference between the gross welfare benefit from the Historical scenario and that from the Incremental scenario, which assumes on a selected border an increment of 100MW extra interconnector capacity for trade. Note that extra capacity in this context need not to be associated with more investments, but should instead be related to more efficient capacity calculation methods.

---

[38] *ACER (2012, table 4 p 52).*

[39] *The simulations were executed accordingly. Firstly, a complete batch with historical data for 2011 was created, including all order books, ATC values, etc. Based on this, the algorithm calculated the results of the Historical scenario. Secondly, the Zero scenario was calculated by altering the ATC value in the historical batch data to zero for one specific interconnector. Then the algorithm ran the calculations for the full year. This was repeated for each interconnector separately. The Incremental scenario was calculated in the same way, although increasing the ATC value in the historical batch data for one interconnector with 100MW.*

> "[Figure 8.17] provides an insight into the relation between incremental and trade gains by interconnection. For instance, the figure shows that the interconnector between Sweden and Finland resulted in a trade gain of 252 million euros per year. The figure also shows which borders would benefit the most from making extra capacity available. For example, the figure indicates that additional capacity between the Netherlands and Norway would yield nearly an additional 12 million euros per year, which is an extra gain of 15%. Also, the case on the Italian–French border which has a percentage extra gain of 33% (19 million euros) is quite remarkable. In contrast, the link between Sweden and Finland has a negligible extra gain of 0.5% of the currently available capacity. Other interesting interconnector candidates for improving capacity include the following links: France-Spain, Germany-Sweden, Sweden-Poland and France-Great Britain." (ACER, 2012, pp67-8).

Note that the incremental gain from more efficient use of interconnectors is exactly that graphed in Figures 8.2 and 8.14 above. To take the specific examples mentioned in the quotation above, an extra 1 (not 100) MW of NL-NO capacity would be worth €1.25 million/MWyr, and IT-FR would be worth €1.9 million/MWyr, or ten times the amounts of Figure 8.2. A simple sum shows that an extra 100 MW capacity on each of the 35 borders in Figure 8.17 would deliver gross benefits of about €124 million per year, or an average of €3.5 million per 100 MW of extra interconnector per year or €35,000/MWyr, or 25-70% of the amounts in Figures 8.2 and 8.14. On the other hand a selective choice of the interconnectors to expand would greatly exceed this average, suggesting that a value of €50,000-€150,000/MWyr for improving coupling on the most inefficient borders is not unreasonable.

8.10 ALLOCATION TO PAST AND FUTURE

The estimates we have considered so far relate to considering the benefits of coupling in general, and we have come up with estimates in the range of 1.5% to 2.5%. The question therefore is how to divide that between what has already been coupled, and what is yet to be coupled. We have therefore attempted to assess what proportion of Europe's transmission capacity (by NTC) is coupled. A difficulty in this is that some links are only partly coupled. In particular, the Nordic market is linked to the NW Europe market by volume coupling, which, according to papers in our literature search, is only about half as effective as price coupling. Also, the GB-FR market is not explicitly coupled, but is indirectly coupled via the Netherlands.

If we say that these partially coupled interconnectors are only "half coupled" we find that 50% of the international interconnector NTC in the EU (including Switzerland and Norway for these purposes) is coupled. If we say they are fully coupled, then the proportion of interconnector that is coupled is 55%. But given that we are applying these proportions to market value, it would appear indicate to weight these proportions by size of the market connected by the interconnectors. Thus weighted, the market-weighted proportion of interconnector capacity that is coupled is 58% (half weighing the partially coupled links) to 66% (fully weighting all coupled links).

This suggests, very roughly, that about 58% - 66% of the economic value of market coupling has already been achieved, and a further 34% - 42% will become available as all the interconnectors in Europe are coupled.

8.11 CONCLUSION

The high value of increasing the efficiency of interconnector use is clear at a number of critical borders. The earlier estimate of the gains from increasing cross-border trade from 10% of consumption to 15% of consumption assuming an average price difference before and after trade of €10/MWh (i.e. an annual value of €80,000/MWyr) might be worth 1% of annual consumption. This might be an under-estimate if some fraction of trade is in a perverse direction. The case studies considered in this appendix of 1.5-2.5% of wholesale electricity value therefore seem reasonable, while expanding the transmission links that are severely congested is also likely to be very cost effective. About 58% - 66% of the economic value of market coupling has already been achieved, and a further 34% - 42% will become available as all the interconnectors in Europe are coupled.

8.12 REFERENCES

ACER (2012) *ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2011* 29 November 2012, Ljubljana, available at http://www.acer.europa.eu/Official_documents/Publications/Documents/ACER%20Market%20Monitoring%20Report.pdf

Moss, Ian (2009) Presentation "APX-ENDEX Market Coupling & BritNed" at the BritNed Connect Seminar, London, 8th December

9. APPENDIX C: COST ASSUMPTIONS FOR ELECTRICITY MODELLING

The following two tables show the main economic assumptions used in the electricity modelling. Whilst it might appear on the face of it that the electricity and gas modelling could be linked through the gas price, the gas price would in turn impact on the generation mix within the PRIMES scenarios. This would also increase the demand for gas and have an impact back to the gas market. Such complex interdependency is beyond the scope of this study.

Table 9.1 Generating Fuel Costs

		CPI Scenario		
		2020	**2025**	**2030**
Crude Oil	EUR/GJ	11.54	12.68	13.82
HFO	EUR/GJ	8.61	9.44	10.26
Uranium	EUR/GJ	0.73	0.73	0.73
Coal	EUR/GJ	3.95	4.22	4.48
Lignite	EUR/GJ	1.58	1.69	1.79
Gas	EUR/GJ	8.54	9.54	10.53
Sun	EUR/GJ	0.00	0.00	0.00
Water	EUR/GJ	0.00	0.00	0.00
Wind	EUR/GJ	0.00	0.00	0.00
Biomass	EUR/GJ	1.00	1.00	1.00
CO2	EUR/t	15.00	24.00	32.00

		RES Scenario		
		2020	**2025**	**2030**
Crude Oil	EUR/GJ	9.66	9.85	10.05
HFO	EUR/GJ	7.25	7.39	7.53
Uranium	EUR/GJ	0.73	0.73	0.73
Coal	EUR/GJ	3.08	3.03	2.97
Lignite	EUR/GJ	1.23	1.21	1.19
Gas	EUR/GJ	8.54	8.43	8.32
Sun	EUR/GJ	0.00	0.00	0.00
Water	EUR/GJ	0.00	0.00	0.00
Wind	EUR/GJ	0.00	0.00	0.00
Biomass	EUR/GJ	1.00	1.00	1.00
CO2	EUR/t	25.00	30.00	35.00

Table 9.2 Capital costs of generation

	Capital cost (€/kW)[1]	Lifetime	WACC	Annuitised cost per kW
CCGT	942	30	7.50%	80
Wind	Low: 2,413 High: 3,064	30	7.50%	204 259
PV	2,873	25	7.50%	258
Peaking capacity	441	40	7.50%	35

Note: [1]Source Black and Veatch 2012