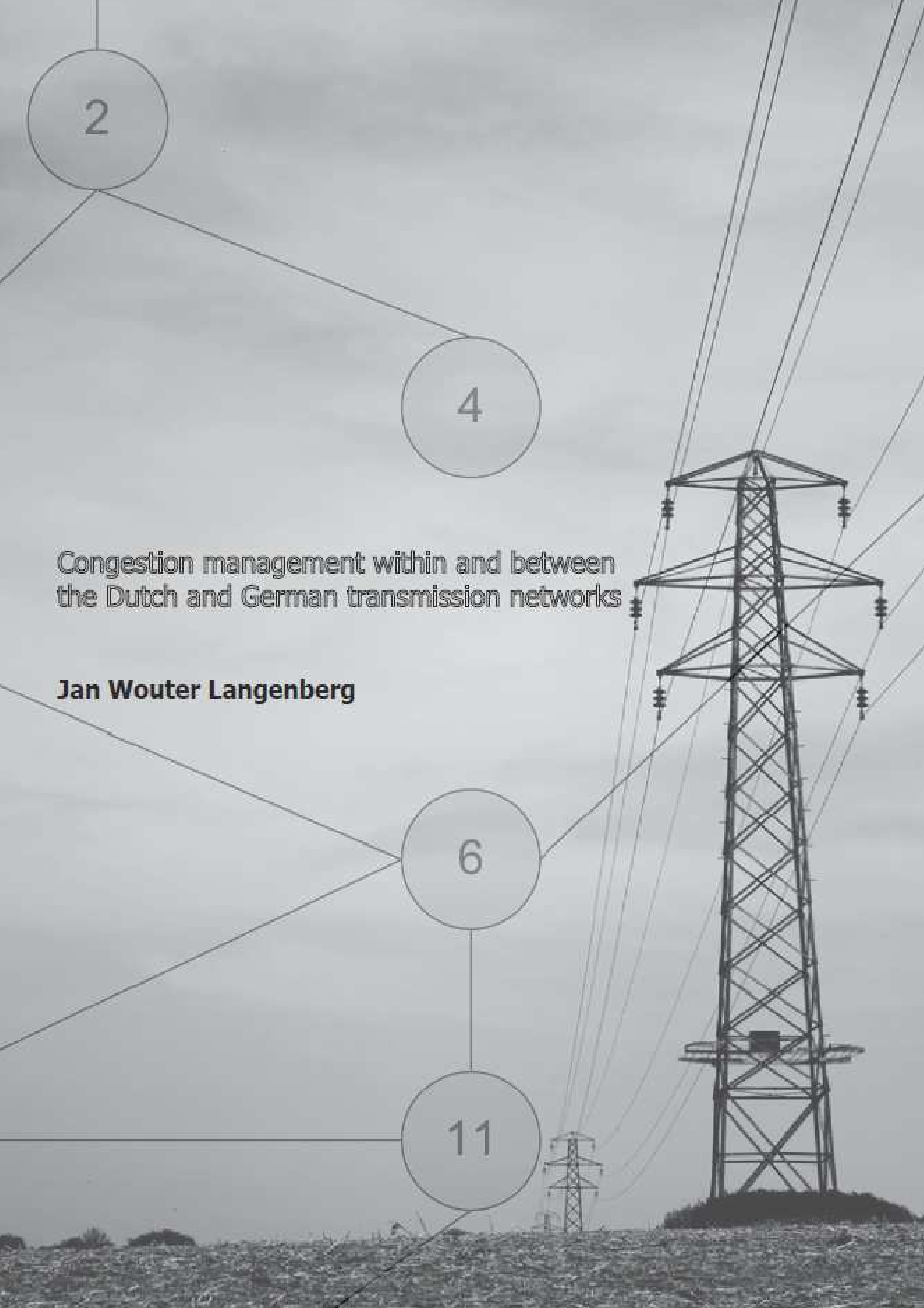

Congestion management within and between the Dutch and German transmission networks

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Preface

Embarking on a research project such as that which lead to this thesis can seem a daunting prospect at times. Completing it would not have been possible without the support and guidance of my supervisors. I would therefore like to take this opportunity to thank them all for their constructive feedback, the many useful suggestions and comments during the course of the work.

I am especially indebted to my primary supervisor, Laurens de Vries for suggesting the research topic and for his thoughts at every stage during the subsequent stages of the project.

My second supervisor, Scott Cunningham, introduced me to the modelling software that I used. His patience in helping me to solve various methodological hurdles and his encouragement were important throughout.

I would also like to express my special thanks to Kick Bruin and Mathieu Fransen of the NMA for making it possible to perform the research at the Dutch Competition Authority. Their interest in the research, and hands-on insight into the electricity market and policy developments were often of great use in getting to grips with this complex subject.

Finally, I would like to thank Margot Weijnen for chairing the examination committee and for her good advice concerning the project.

Not directly related to the research itself, but no less crucial to its succes, was the positive support of my friends and family – in particular, my parents, whose faith in my abilities was more consistent than my own.

Summary

Electricity is an essential service that can be seen as a utility necessary for modern life. It is typically generated in large scale power plants, and must then be transported through a capital intensive infrastructure known as the transmission grid. It can not be easily stored for later use, which implies that supply and demand of it must be balanced at all times.
The capacity of the grid to transport electricity is limited. If it is overburdened, costly loss of property and the failure of the network can result. Electricity transport is special, because the marginal costs for transport from one place to another often depend on what is happening elsewhere in the system. This is a consequence of the fact that flows through a network depend on physical properties rather than exclusively following from economic transactions.

The term ‘congestion’ applies when the capacity of the transmission network is not sufficient in order to meet our transport needs for electricity. Such congestion is currently an issue in the Netherlands, where investment in generation capacity is expected to outpace the construction of stronger transmission networks during the coming years. Congestion can be managed through the allocation of scarce capacity beforehand, using methods such as explicit or implicit auctions. This is presently the situation on the transmission links on the borders between the Netherlands and neighbouring countries. It can also be managed while maintaining a single price within the country, using methods such as counter trade that correct infeasible electricity flows closer to the real time of power plant dispatch while maintaining a single price for electricity in an area. This costs money, as the power which would have been dispatched is less expensive than that which is constrained on instead.

A model was built which can determine both the economic outcomes of electricity trade within the markets (quantities produced and prices paid at each location) and the resulting flows of electricity through the networks. This model was used to compare methods for managing congestion for a set of plausible scenarios for 2014, involving potential additions to the available generation capacity and incidental conditions which may contribute to congestion. The results suggest that the additional costs to society in the form of the increased expense resulting from counter trade are quite modest compared to the total magnitude of power costs. The most significant congestion costs were found given large amounts of wind power in the north of the Netherlands and Germany, around 70 000 Euros per hour. Those costs were roughly estimated to imply annual costs of up to 80 million Euros. The difference between the optimal dispatch achievable using locational prices and the counter trade is around 5% of congestion cost.

If the scenario with wind energy occurs, the model predicts most of the additional costs of congestion related to counter trade could be avoided by implementing price zones within Germany. Increased interconnection on the borders between the Netherlands and Germany was investigated. This would reduce some but not all congestion, as national networks would remain congested. The research also identified the fact that decreasing tradable interconnection capacity on the borders could allow TSOs to avoid some of the expense of counter trade within their networks. This could potentially cost society at least as much as managing the congestion.

Based on this research, policymakers are advised to consider counter trade as a feasible option if developments in new electricity plants in the CWE region remain close to the expectations forming the input for the reference scenario described in this thesis. However, they should note that the cost estimates for using this method were based on conservative assumptions

relating to perfect competition and available transmission capacity. If developments such as the rapid realization of wind power occur, which could lead to greater congestion than in the reference scenario, policymakers are advised to closely monitor whether market performance conforms to these conservative assumptions. If significant congestion is caused due to rapid wind power development in the north of the Netherlands and Germany, policymakers are advised to consider the feasibility of implementing two price zones within Germany. Doing so would allow congestion to be managed at lower cost to society than by using counter trade. If and when that situation occurs, regulators would also be advised to monitor the possibilities for abuse of market power by market participants who take on the role of pivotal suppliers for the purpose of relieving congestion.

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Overview of symbols and acronyms

Symbol	Explanation
Q_s (i)	Quantity of power supplied at a node 'i'
Q_d (i)	Quantity of power demanded at a node 'i'
Q_i (i)	Net quantity of power injected into to or withdrawn from the grid at a node 'i'
$Q_{i,j}$	Quantity of power transported between two nodes 'i' and 'j'
$Q_{max\ i,j}$	Maximum quantity of power that can be transported over a transmission link connecting two nodes 'i' and 'j'
X_{ij}	Reactance of a transmission link connecting two nodes 'i' and 'j' (in Ohms)
$P_{d\ (i)}$	Marginal price of power paid by consumers at a node i
$P_{s\ (i)}$	Marginal cost of power produced at a node i
P_k	Price of power within a price zone 'k'
P_{fij}	See Q_{ij}
P(i)	See Q_i(i)
θ(i)	Theta, the voltage angle at a given node 'i'
a	intercept of inverse demand curve for electricity with y axis
b	slope of inverse demand curves for electricity
c	slope of cost curves for supply of electricity
AC	Alternating Current
ATC	Available Transmission Capacity
CfD	Contract for Differences
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CPSM	Consumer and Producer Surplus Maximization problem
CWE	Central West European region (BeNeLux countries, Germany and France)
CT	Counter Trade
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators for Electricity
FBMC	Flow-based Market Coupling
FTR	Financial Transmission Rights
GAMS	General Algebraic Modelling System
MW(h)	Mega Watt (hours) of power
NTC	Net Transmission Capacity
NordReg	organization of Nordic Regulators
Nordel	organization of Nordic TSOs
OD	Optimal Dispatch
PTDF	Power Transmission Distribution Factor
UCTE	Union for the Coordination of Transmission in Europe, superseded by ENTSO-E
UD	Unconstrained Dispatch

1 Introduction and research questions

The electricity market is different from any other due to the physical properties associated with its generation, transport from the location of production to the consumer and its end use. The first section of this chapter (1.1) will discuss the most relevant such aspects, in order to introduce the reader to the complex context of this research topic.

This thesis deals with research related in particular to *congestion* occurring on the transmission system (i.e. the network infrastructure used to transport electricity from producers to consumers). The second section (1.2) explains what is meant by the term congestion when applied to electricity networks. The third section (1.3) discusses the relevance of the issue of congestion from the perspective of recent developments in the Dutch electricity grid, while section 1.4 provides a review of the relevant academic literature. Section five (1.5) concludes the chapter with the definition of four specific research questions related to the topic. The research and results described in this thesis aim to add to the scientific knowledge of the topic of congestion management by answering these questions.

1.1 Electricity: An exceptional market

Electricity is an essential service which can be seen as a utility necessary for modern life. It is typically generated in large scale power plants, and must then be transported through a capital-intensive infrastructure known as the transmission grid. It cannot be easily stored for later use, which implies that supply and demand of it must be balanced at all times. Demand for electricity varies, both over any given day and over the year as a whole, depending on the differing amounts of energy which we require in the course of our daily activities and between the seasons. The capacity of power plants and the grid respectively to generate and transmit the electricity we demand must therefore be sufficient to meet the highest such level of demand, or 'peak load'. The capacity of the grid to transport electricity is limited by the physical properties of the cables, transformers and other installations used to do so. If overburdened, these can burn out, resulting in costly loss of property, and the failure of the network, with a high direct cost to society. Finally, electricity transport is special, because the marginal costs for transport from one place to another often depend on what is happening elsewhere in the system (Hogan, 1997). Injecting power in one place to move it to another can reduce the amount of physical capacity required for transport in the opposite direction.

Economically, these factors can be seen as indicating the potential for strong external effects resulting from many of the actions taken by the many parties involved in electricity supply. Combined, they help to explain the strong public interest that ensured its historic provision through vertically integrated supply chains. Deregulation of the sector in the 1990's was driven by the goal of increased efficiency, and to be achieved by splitting those aspects of electricity supply that have a natural monopoly character (such as the operation of the grid) from those with competitive potential (such as the generation of the electricity and the retail market for consumers). Electricity supply is now often traded by parties both through bilateral contracts and through a new institution: the power exchange for electricity. In the Netherlands this is the Amsterdam Power Exchange (APX). These parties must pay the independent operator of the transmission system, the TSO for the service of transporting the necessary electricity to its destination.

One consequence of unbundling this supply chain is that investment in the grid and in generation plants is no longer as easily coordinated as was the case in the past. The lead time for investment in new generation capacity is shorter than that for additional investment in transmission infrastructure, while payments to the Transmission System Operator take place based on the current transport of electricity.

In the initial years following deregulation, transmission capacity in the Netherlands always sufficed to transport those quantities which market parties aimed to supply and demand. In recent years however, it has become increasingly apparent that this may no longer be the case in the medium-term future. That means that a system for managing congestion - which occurs when transmission capacity is not sufficient to meet the desired transport of electricity - may soon become necessary.

1.2 Congestion management in electricity networks

What is congestion? The term 'congestion' applies when the capacity of the transmission network is not sufficient in order to meet our transport needs for electricity. Two forms of congestion can be distinguished: physical congestion, which occurs when generation and transport resources are simply insufficient to meet demand in a given area, and economic congestion, which occurs when in principle the infrastructure should allow for demand to be met, but the market outcome is such that the network would be overburdened such a trade were to take place (Knops, 2008).

The term 'congestion management' will be used in this thesis to refer to those policies with which the second form of congestion occurring on the electricity grid may be dealt with. Managing congestion is just one of three relevant cost drivers determining the price of electricity transmission, which must also cover the costs of providing ancillary services (such as reactive power provision and spinning reserve) and losses during transport. All three of these aspects translate into technologically complex management issues, which justify the central coordination of a TSO. Congestion management constitutes the most significant economic impact of the three however, and may also affect the scope of the market and thereby the distribution of market power (Chao and Peck, 1996).

Managing such congestion is a complicated issue because the actual flows of power that exist in practice follow from the physical laws governing electricity networks. Their course thus depends on both the market outcome and on physical properties such as the resistance of the cables in the transmission infrastructure. Thus, what actually happens when power is generated in one place and used in another does not necessarily correspond to the direct path implied by those contracts which were negotiated beforehand within the marketplace for electricity supply. This may not be an issue when the overall capacity of the network is sufficient to allow desired trades to take place and be transported, but can become highly relevant if and when congestion occurs.

Electricity moving from one node to another within a network can and does flow through simultaneously along multiple parallel routes, depending on the resistance of lines, rather than moving exclusively via the most direct path. In doing so, it can cross in and out of the control areas of TSOs (Transmission System Operators) – the parties which are responsible for management of the infrastructure – a phenomenon known as loop flows.

Furthermore, because of the swings in electricity demand, transactions covering electricity supply actually take place within several different time frames, ranging from forward contracts dealing with the supply of power far in advance to day-ahead markets and the balancing market, allowing almost continuous corrections of the differences between predicted and actual electricity use. Congestion management methods may therefore be used in advance, to allocate scarce transmission capacity such that congestion does not take place, but the term may also apply to operational measures taken in the short term to correct system operations in the event that it arises (Gjerde, 2005).

Different methods for management of congestion may have the potential to affect the interests of the many parties involved in the electricity supply chain: the various parties trading in the wholesale market, those organizations responsible for managing transmission and distribution networks for electricity and the consumers of electricity in both the Netherlands and neighbouring countries. This has played a part in making the recent discussion concerning the potential choice and possible implementation of such methods an important issue for Dutch policy makers.

1.3 The relevance of congestion management for the Dutch and neighbouring electricity markets

The Dutch electricity infrastructure has become more heavily used due to recent additions to power generation capacity, and is expected to become more so in the light of existing proposals for new plants (D-Cision, 2009, page 5 and EZ position paper). Currently, the spot market for electricity in the Netherlands, which forms part of the power exchange APX, clears with a single uniform price, implicitly assuming that transmission between suppliers and consumers of electricity will be possible between any two locations within the Netherlands.

Until now, reaching the limits of the transmission infrastructure's capacity to transport peak flows to meet demand therefore implied the necessity of either rejection of permission to connect new plants to the network or of limiting such permission, for example by agreeing to only under special conditions in the form of 'runback contracts' while grid capacity was expanded. Such contracts allowed for connection of the plant to the grid, but enforced provisions allowing the TSO (Transmission System Operator) to oblige the operator to reduce its level of generation without compensation, if this is necessary to manage congestion.

Congestion management as a policy choice

Over the long term, a structural expansion of transmission capacity should help to alleviate this situation. In the short term, using a system of congestion management has been proposed by the TSO to ensure that new entrants may be connected in the interim (TenneT, 2008a). In reaction to this the organization representing the existing electricity supply industry presented its own plan (MinEZ, 2008). These two proposals differ in detail, but when based on redispatching generation capacity and compensating the owners of the plants in question, using bids by market players to avoid producing would be a form of ‘counter trading’. Other policy options, such as more traditional redispatching remain available as alternatives, while theory and practice in other electricity markets suggest that a number of alternatives exist based on allocation through pricing of capacity, which have not (yet) been fully considered in the Dutch national context.

While new investments in the transmission network are being realized but the occurrence of a higher level of demand for transport of electricity is expected than can be satisfied with the current infrastructure, using any one of these methods could allow the TSO to ensure congestion does not occur. Such an approach would be more market conforming than the existing system, as no discrimination would occur between existing and new market participants. Either refusing to connect new plants or doing so under restrictive ‘run back’ contracts will result in an uneven playing field between new entrants to the electricity supply market and incumbent players. The previous situation could therefore be seen to be undesirable. However, this improvement in connection policy will come at a cost: increasing congestion, which will need to be managed. The costs of doing so using either redispatch or counter trade have been roughly[1] estimated by Tennet (cited in D-Cision, 2009) at 100 million Euros in 2009.

Furthermore, the legal difficulties surrounding the use of runback contracts and the connection of new plants have created uncertainty for the entrants (Tennet, 2008c). Without sufficient economic incentives and conditions that encourage investment in generation capacity, the security of Dutch electricity supply may come under pressure.

Lastly, congestion management may affect each the policy goals listed in the Electricity Act of 1998. These criteria, such as transparency, effective competition and proper market performance are important aims for market regulation. Their relevance for policymakers also applies to choices concerning congestion management.

Congestion management within the Dutch network from an international perspective

While the need for internal congestion management (i.e. within the Dutch grid) is a relatively recent issue, congestion along the interconnectors linking the Netherlands with the electricity markets in neighbouring countries has been managed for some time. Differing approaches that are currently applied include market coupling (a form of implicit auction introduced along borders between the Netherlands, Belgium and France) and the use of explicit auctions for available capacity (used along the German border and the Nor-Ned cable to Norway).

[1] No further details on the method used for this estimate are given by Tennet. However, known costs for managing constraints within a range of European countries, using counter trade or redispatch are scaled to reflect Dutch market size in D-Cision (2009). The resulting figures suggest that the Tennet estimate is within the same order of magnitude (tens to hundreds of millions of Euros per annum) as in other EU member states.

The matter of which approach should be applied has not yet been fully settled, but the European Union has mandated market-based solutions for interconnector congestion between its member states (through regulation 1228/2003/EC) since 2006. Given the successful introduction of trilateral market coupling between France, Belgium and the Netherlands, this method is future choice for managing the congestion on interconnectors between countries[2]. An outstanding issue with such proposals is that determining capacities to safely use in a meshed system expanding market coupling to Germany from just the Netherlands, Belgium and France remains a practical challenge (Sharma, 2007). This point is also made when considering the method from a European perspective (Ehrenmann and Smeers, 2005).

The method applied to manage congestion along interconnectors spanning the national borders is relevant to the choice of a method for congestion within the Netherlands, as their effects are mutually interdependent. When different congestion management regimes with differing resulting financial incentives are linked, this can have serious consequences. For example, (Bjørndal and Jornsten, 2007) show that the combination of counter trading and market splitting can result in an incentive for a TSO to prevent managing 'internal' congestion by reducing the capacity for cross border trade.

Because electricity flows are governed by their physical properties (notably Kirchhoff's laws) rather than by economic transactions, unexpected flows may occur through the Dutch network as a result of a combination of high wind production in the north of Germany (Leuthold et al., 2008) and a lack of transmission strength between Northern and southern Germany. Such flows could imply significant financial costs occur for the Dutch TSO, if they use counter trading to manage congestion on the Dutch network. The question of how to allocate them is not a simple one.

All these issues suggest that research investigating congestion management within the Netherlands, while taking into account the relevant international context, could deliver valuable insight informing the policy choice between possible methods. This thesis covers the results of such research. An overview of the academic literature is first provided, while in section 1.5 the relevant research questions are formulated and the structure of this thesis is explained.

1.4 Literature review

In the previous sections of this chapter, the problem of congestion management within the Dutch electricity networks was introduced. It is the aim of this thesis to provide a contribution that strengthens the scientific knowledge of this issue and informs policy makers.

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[2] Flow-based market coupling (FBMC) has been formally agreed to as the desired approach, in a memorandum of understanding between the TSOs and other parties concerned. FBMC is an improved form of market coupling, using a more accurate representation of the electricity grid between countries but maintaining the aggregation of national markets and links within countries. (Pentalateral forum, 2007. Memorandum of understanding concerning the introduction of flow-based market coupling. Ministry of Economic Affairs, The Hague.)

Although the import of the issue from a Dutch perspective is relatively recent, much existing research has already been done in fields which overlap with the subject. In this section, a brief overview of some of the relevant literature relating to network infrastructures, electricity transmission and congestion management is therefore provided. The goal is not to provide an exhaustive overview, but rather to serve the reader by giving an idea of how existing research can help to understand some of the complex nature of the technological and economic systems related to the provision of electricity.

Parallels with other network infrastructures

Although this thesis focuses on electricity transmission, parallels may be drawn with other network infrastructures. The regulation of markets for electricity is discussed alongside telecommunication, water and transport infrastructures by Newbery (2006). Künneke (2008) suggests that such technical infrastructures co-evolve with the policies which govern them, but that this does not necessarily translate into coherence between the two. Using the liberalization of the electricity sector as an example, he notes that the decentralization of much of this sector was not translated into a similar shift in the critical coordinating functions – such as between real-time capacity management problems and long-term investment trends. Although such research can help to understand and explain the broader context of policy shifts in network industries, specific policy problems relating to network operation demand specific solutions due to physical differences between the underlying technological systems.

Transmission policy in a market environment

The consequences of some of the major trends characterizing the electricity sector in particular have formed the subject of research by authors such as Hunt (2002), Hogan (2002) and Blumsack et al (2006). The difficulties encountered since the first moves towards a less strongly vertically integrated electricity supply sector often lead such authors to stress either that more sophistication is needed in market design (Hogan, 2002) to achieve the potential benefits of liberalization, or to question whether these benefits are being achieved at all (Blumsack et al., 2006). Other authors, such as Joskow (2008) place more emphasis on the positive effects that well-designed institutions can have on electricity sector performance.

A recurring subject within such analyses is the question of how to organize electricity transmission in general, and how best to deal with the task of congestion management in particular. Within Europe, much of the attention of the actors within the sector has been devoted to the allocation of capacity to transmit power over the interconnectors linking different national markets[3]. Authors such as Perez-Arriaga and Olmos (2005) and Imran and Bialek (2008) have been critical of the potential to move to more complicated systems than explicit auctions, given the centralization implied compared to existing institutions.

[3] For example, the regulators group Ergeg (2009), published a report on compliance with the congestion management guidelines on interconnectors while ETSO and Europex, the European organizations for TSOs and power exchanges, published a study (2009) considering cross-border congestion management and capacity allocation between countries and regions.

More recently, increased emphasis has been placed on congestion within national networks, which has become the cause of significant costs in countries such as Italy and Great Britain (D-Cision, 2009). This is partly because in some countries, the policy of connecting new power plants has become less rigid, while the lead times of such plants are far shorter than the time that is required to plan, approve and build new transmission infrastructure. Another cause may be the increasing share of decentralized and renewable production, such as large wind parks and small CHP power plants. In any case, once congestion occurs or increases, the policy question of how to manage it will become more relevant.

The desirability of congestion management methods

Congestion management can be performed in multiple ways, as is discussed from the perspective of the Dutch policy perspective in chapter two of this thesis. Much of the academic debate has focused specifically on the desirability of implementing implicit auction approaches such as nodal or zonal prices for electricity when congestion occurs, rather than traditional redispatching or countertrading.

The nodal pricing approach is based on the theory of spot pricing in electricity markets introduced by Schweppe et al (1988) and was first suggested by Hogan (1992). Proponents have argued that such an approach offers the most efficient allocation of the scarce grid capacity in the short term, as well as sending the correct price signals for producers and consumers in the long run (Rious et al., 2008), while critics such as Rosenberg (2000) have questioned whether this might not result in flawed outcomes, such as perverse incentives to retain congestion or large discrepancies between the short-term prices for using congested transmission links and the actual operational costs of the transmission.

Concerns raised about the approach include the question of whether such costs will be an accurate price signal in systems which must be designed in order to minimize transport losses of a similar order of magnitude or which are over-dimensioned due to the asymmetric social costs of blackouts. Furthermore, the uncertainty in their level may be difficult to hedge using financial instruments, such as financial transmission rights (Brunekreeft et al., 2005). Nodal pricing has been used within the Pennsylvania-New Jersey-Maryland (PJM) market and in New Zealand for some time, although some authors such as Blumsack (2006) have noted that in the former case, data shows that congestion costs have increased by a factor of 10 since their introduction in real terms (PJM, 2004).

Zonal pricing as an alternative that sits somewhere in between classic redispatching and nodal pricing - although prices can be differed in other to reflect scarce transmission capacity, this is done between zones rather than all the nodes within the network. The general properties of such zones and the difficulty in their determination have been discussed by authors such as Bjørndal and Jornsten (2001) and Walton and Tabors (Walton and Tabors, 1996). Critical authors such as Stoft (1997) and Smeers (2008) have noted that aggregating nodes to form zones still simplifies the reality of the electrical transmission network, while Bjørndal and Jornsten (2007) suggest that it can offer outcomes which are close to nodal pricing benchmarks in terms of social welfare.

Research based on network models

Academic studies comparing such congestion management methods on a quantitative basis are generally based on network models, often using a ‘DC’ linear approximation of load-flows. Notable examples for European countries include Green’s study of the U.K. (Green, 2007), the Balmorel model used in (EA Energy Analyses et al., 2008) for the Nordic markets, and the Elmod model focusing on the German market by Leuthold et al. (Leuthold et al., 2008).

These research efforts have suggested potential increases in the social surplus resulting from nodal pricing in the order of 0-10% when congestion occurs, but these studies are often based on perfect competition assumptions, rough variable cost price estimates, simplified network structures without losses in transmission and other simplifications of the actual systems involved. This can make it difficult to translate their outcomes to practical numbers which are applicable in making policy choices. Comparisons such as that conducted by Neuhoff et al. (2005) suggest that once such models depart from these assumptions, for example by representing imperfect competition, the results may also become less consistent and more dependent on the way in which the model is constructed.

Research relating to the CWE region

Specific studies for the Netherlands have been based on the data and three node scope of the Competes model which was first published by Hobbs and Rijkers (2004) and later expanded to cover neighbouring countries[4]. As yet unpublished work by Pepermans (2004) refers to a detailed model of the Belgian electricity grid and market.

The first of these sources focused on the interconnections between countries, noting that at the time of writing congestion within the Dutch network did not occur regularly. Work as part of a thesis by Sharma (2007) and later reported by De Jong (2009) looked specifically at flow-based market coupling between the Netherlands and neighbouring countries. This is a system in which the aggregation of transmission links between countries within the network model used to determine available capacity for trade between countries is improved, although each national market is still aggregated to a single node. Work on the introduction of flow-based market coupling by the TSOs continues - a year of trade using this proposed change to the system is currently being simulated in order to assess its affects more accurately.

1.5 Formulation of research questions and structure of thesis

This research is aimed at investigating the issue of congestion management, applied within and between the networks of Germany and the Netherlands. The interconnectors with the markets of Belgium and France will also be taken into account, but internal congestion within these networks falls outside of the scope of the research due to time constraints.

The central research question is formulated as follows:

[4] Although when this model was expanded for studies of European interconnectors, the level of detail for the Dutch network was significantly reduced

Q1 "*What is the most suitable congestion management method for managing congestion within the Dutch and German electricity markets, assuming market coupling will be introduced between the Netherlands and Germany*?"

The research should result in sufficient insight into this issue to allow a considered answer to be formulated to this central question. Specifically the congestion methods of interest are limited to the counter trade and implicit auction approaches that are considered relevant alternatives for policymakers. The answer is discussed in chapter 6 based on the research findings.

As was noted elsewhere (1.3), several different criteria may be considered relevant to the choice of a congestion management method. The exact definition of the concept of 'suitability' within the context of the research question may therefore be a matter of contention. This leads to the formulation of the following sub question:

Q2a *"What are the relevant criteria for choosing a suitable method for congestion management?"*

The possible answers to this question are considered in the first section of chapter two of this thesis (2.1).

As was touched upon in the previous sections (1.3 / 1.4), several theoretical alternatives for managing congestion within a national electricity network (or a control area covering part of a country) exist, such as nodal pricing or zonal pricing. These methods can generally also be applied for the connections that cross national borders and link differing electric networks (interconnectors), although the context may differ. Before any choice of a congestion management method can be considered, insight into the range of possible methods is necessary. This leads to the following research sub questions:

Q2b *"Which theoretical methods exist for congestion management?"*

An overview of the most relevant such methods forms the basis for the second section of chapter two of this thesis (2.2).

In order to be able to compare the practical consequences of the possible alternatives for congestion management, it is important to gain insight into their expected performance.

Market coupling using (national) price zones is assumed to be the most likely method towards which the management of congestion on interconnectors between the Netherlands and her neighbours is expected to evolve, given the success of this method in allowing more efficient use of the interconnectors between the Netherlands, Belgium and France. A relevant question is therefore what the effects of applying an approach based on price zones to manage congestion both *within* countries such as the Netherlands and Germany and *between* the countries would be.

This leads to the formulation of the following sub question:

Q3 "*What are the economic effects of introducing zonal pricing within and between the Netherlands and Germany to manage congestion?"*

In order to be able to evaluate and compare the effects of alternatives for congestion management using a zonal pricing method, it is important to investigate what the quantitative effects of these would be. The research should deliver a clear set of measurable outcomes, which indicate where possible the expected effects related to the public goals regarding electricity market performance following from Q2a. In this case, in particular the model should allow the calculation of:

- The social costs of congestion management within price zones, under various defined zones[5]
- Differing direct market outcomes (e.g. the prices in each zone) under various possible plausible price zones
- The flows of electricity between locations
- The possible effects of introducing different price zones, given various scenarios representing plausible causes of congestion (e.g. high wind production along North sea, technical reasons for shutdown of transmission line, high summer demand peak)

Of specific interest will be the following aspects:

Q3a: *What are the potential incentives for TSO to save money by 'moving' congestion (by declaring a low transmission capacity) from the national network to international borders, if the national network represents a single price zone?*

Q3b: What is the impact on the congestion of the Dutch electricity network resulting from unified or diverse German electricity price zones?

Q3c: How could increased interconnection capacity between the Netherlands and Germany affect congestion within the Netherlands?

Answers to these questions are based on the main part of the research, which was performed using a model of the Dutch and neighbouring electricity markets. The methodology employed in the construction of the model and the relevant methodological assumptions form the basis for the first sections of chapter three of this thesis (3.1, 3.2, and 3.3). Chapter four describes the relevant results to question 3 (4.1) and the sub questions (4.2).

A quantitative model can help to estimate a number of the consequences of a choice for a method for congestion management. However, as is discussed in (2.1) some criteria which are relevant are difficult to capture with such research. Here, existing international practice can

[5] This includes the loss in welfare for both consumers and suppliers due to inefficient plants being dispatched.

help to understand what some of the implications of different available choices may be. This leads to the formulation of the following research question:

Q4 “*What can be learnt from the existing practice of zonal pricing and other congestion management methods*?”

The third section of chapter two of this thesis (2.3) therefore describes the findings of a brief case study based on literature research investigating the congestion management practices in the Nordic markets, aiming to answer this question. The Nordic electricity markets and networks resemble those of the CWE in that congestion can occur between the north and the south and in the use of market coupling for interconnectors between national markets.

1.6 Scope and methodology of research

The research is limited geographically to the electricity markets of the Central West European market, i.e. the Netherlands, Belgium, France and Germany. More specifically, it looks at congestion management within the Netherlands and Germany, and between these countries and those to the south of the Dutch network. In line with current congestion management practice, the focus is on trading in the day-ahead markets and bottlenecks on the high-voltage transmission network (380kV). Of particular interest are the economic outcomes following from the application of congestion management methods which price both the scarcity of energy and of transmission capacity, using implicit auctions and the alternatives currently being proposed for the Dutch network such as counter trading.

To assess the potential economic effects of such implicit auctions quantitatively, a modelling approach is employed. More specifically, a ‘DC approximation’ or linear representation of the AC high voltage network and the potential flows resulting from market outcomes under various price zones is employed. The market is represented in an aggregated way under the assumption of perfect competition. The qualitative research preceding the model investigates the policy framework for congestion management. It is based on a review of the academic and public literature relating to the topic, and forms the basis for the interpretation of the modelling results.

1.7 Conclusions and structure of this thesis

This chapter forms an introduction to policy issues related to electricity markets, the topic of congestion on the transmission networks for electricity and the relevance of that topic for research. In the previous two sections, research questions are formulated and the scope and methodology used to address them during this research are briefly explained.

Chapter 2 of this thesis focuses on the policy framework for congestion management. The first section (2.1) gives a description of the European and Dutch legal framework limiting policy choices. Section 2.2 discusses possible criteria which may be employed in order to evaluate the outcomes of applying such a method. The following section (2.3) investigates the possible methods which could be employed. The fourth section (2.4) of the chapter discusses what can be learnt from the example of congestion management policy in the Nordic markets.

Chapter 3 of this thesis introduces the model that is used for the quantitative part of the research. The first section (3.1) introduces the assumptions related to the representation of the electricity market and their consequences. The second section (3.2) discusses the assumptions related to the representation of the transmission network, and their consequences. The following section (3.3) explains the choices related to the scope of the model. The final section (3.4) of the chapter deals with the estimation of the various parameters necessary for use of the model.

Chapter 4 of this thesis discusses the results of the quantitative research and their interpretation in the light of the existing academic literature. Chapter 5 concludes the thesis by offering a discussion of the relevance of these research findings for policymakers, reflecting on the methodology employed and its limitations and listing some promising avenues for future research.

2 A policy framework for assessing congestion management

Chapter 1 of this thesis introduces the issue of congestion management and explains its particular relevance with regard to the markets for electricity and the transmission infrastructure which is used to transport it. The goal of this chapter is to provide an initial answer to two research questions introduced in chapter one that are relevant to policymakers dealing with the topic of congestion management.

First, it is important to know what options are available to choose: which theoretical methods exist for congestion management? (Question 2b). Once this is clear, policymakers also need to know on what grounds their judgment can be based: what are the relevant criteria for choosing a suitable method for congestion management? (Question 2a).

The first section of this chapter discusses the relevant existing European and Dutch legal and policy context, as this constricts the potentially available congestion management methods. The following section (2.2) continues by describing the differences between methods which may be applied, focusing in particular on those relevant to the Dutch situation. Section 2.3 discusses possible criteria by which suitability of these congestion management methods could be judged. Section 2.4 concludes, by investigating what may be learnt from the practice of congestion management in the Nordic markets. These sections of this research are based on a review of the available academic literature.

2.1 The existing European legal and policy framework

Much of the past attention regarding congestion management has focused on management of interconnectors between national networks. European policy on this issue has been discussed by the various actors at the Florence fora. Coinciding with the first Energy directive, the aim of the initial participants of these meetings was to establish tarifcation and trade mechanisms that would reflect costs and the principles of non-discrimination and transparency (De Jong, 2009).

From the year 2000 onwards, these principles were translated into basic guidelines for congestion management, stating that methods should deal with short run congestion in an efficient manner while simultaneously providing incentives for investment and that network capacity should be used at the maximum capacity complying with safe operation. Congestion rents were to be used either for ensuring firmness of capacity, relieving congestion or reducing network tariffs. The relevant regulation (1228/2003/EC) was later amended in 2006 (decision 2006/770/EC), bringing a number of these criteria more specifically into European law.

The regulation (article 6:5) specifies that TSOs must as far as technically possible net the capacity requirements of any flows in opposite direction over congested interconnectors.

With regard to interconnectors, congestion rents may not take the form of additional income for the TSO affected. Article 6:6 of the regulation dictates that the revenues in question should be applied for either “guaranteeing the actual availability of the allocated capacity”, for “network investments maintaining or increasing interconnection capacities” or “as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified”. The regulation thus strives for a neutral allocation of the rents from congestion management through methods based on pricing.

For international transmission links, regulation 1228/2003/EC also touches on the principles of transparency and non discrimination. It states “The precondition for effective competition in the internal market is non-discriminatory and transparent charges for network use including interconnecting lines in the transmission system” within the considerations. The amended annex (article 1.5) begins by prescribing that congestion management methods shall “give efficient economic signals to market participants and TSOs, promote competition and be suitable for regional and community wide application”. Article 2.1 prescribes the use of “market-based” methods for congestion management on interconnectors (explicit or implicit auctions).

It also specifies that TSOs should be guided by the principles of “cost effectiveness and minimization of negative impacts on the Internal Electricity Market”, explicitly prohibiting limitation of interconnection capacity in order to solve internal congestion (article 1.7).

One may conclude that European legislation identifies a number of relevant criteria and broadly indicates what policy choices related to congestion management should aim to achieve. Methods for the allocation of capacity on interconnectors are limited to market-based methods. However, the exact interpretation of these principles and the application of these methods can and does leave room for significant differences in policy. Furthermore, the legal framework is currently limited to the allocation of capacity on interconnectors between member states, rather than the transmission links in networks within them.

Dutch legislation and policy – the 1998 electricity act

The national legislation in the Netherlands reflects the broader European energy legislation, and also covers a number of the criteria touched upon in the congestion management guidelines. For example, TSOs are required to connect any party seeking to transport electricity over the network at a “reasonable price, unless transport capacity is not reasonably available” (article 24, 1/2) and to “refrain from discrimination in doing this” (article 24, 3). Its conditions should be reasonable, objective and non-discriminatory (article 26a, 1) and tariffs objective, transparent, non discriminatory and reflective of costs (article 26, 3).

The Dutch regulator has noted the importance of access to the network and the existence of problems relating to available capacity in a recent position paper (NMa, 2009b). An emphasis was placed on the legally codified responsibility of the TSO to connect parties where reasonably possible, as mentioned elsewhere in this section and discussed the interpretation of reliability benchmarks within the work of the TSO. This can be seen within the context of the criterion of non-discrimination. Currently, proposed legislation is under debate which would ensure that renewable generation is exempt from congestion management within the Netherlands.

An earlier independent study (BrattleGroup, 2007) concerning the connection policy employed by the TSO and a policy advice (NMa, 2007) by the Dutch regulator were carried out following a complaint at the end of 2006 from market participants about the lack of possibilities for connection of their planned investment in electricity generation capacity at two sites: the Maasvlakte in Rotterdam and the Eemshaven in Groningen. The advice suggested that the TSO's interpretation of the legal requirements of non-discrimination, transparency and confidentiality meant that optimal market performance was not being achieved, encouraging strategic behaviour with regard to requesting connection of potential new capacity. Implementing a congestion management would allow new capacity to be connected in spite of the potential for congestion, allowing this problem to be addressed.

While this thesis focuses on the specific perspective of congestion management, such issues show that the criteria investigated here in relation to this topic are relevant to electricity market regulation in a more general sense. Choosing a 'suitable' congestion management method may in practice involve trade-offs: not just between the effects on the criteria discussed in the first part of this section and in section 2.3, but also between effective market performance and other policy goals for the electricity sector. Dutch legislation describes some of these goals, but does not dictate how they should be achieved with regard to congestion management.

2.2 Congestion management methods

Congestion within and between networks for electricity transmission may be managed using a number of methods as explained by authors such as Knops et al. (2001). This section of the chapter will discuss the most relevant options for the Netherlands, notably methods for allocating capacity *ex ante* and for adjusting market outcomes *ex post* of day-ahead trading. This is not the only theoretical criterion with which congestion management methods may be grouped (e.g. four aspects are identified by de Jong and Hakvoort (De Jong and Hakvoort, 2007)) but it is judged to be the most important distinction between those methods applicable within national networks[6].

Not all of the theoretical alternatives[7] are considered feasible for possible implementation within the Netherlands, due to the institutional requirements, the practical scope of the electricity grid and the congestion which will need to be managed.

Of particular interest to this research are those methods currently applied or under consideration for use both within the Netherlands and between the Dutch network and neighbouring networks and potential market-based alternatives. The rest of this section

[6] Other commonly made distinctions refer to issues such as regional coordination between different TSOs, which is mainly an issue relevant to interconnectors.
[7] For example, other methods are possible in theory such as *pro-rata* allocation of some or all transmission capacity to a favoured incumbent.

therefore explains the remaining policy options which are currently being considered as either viable alternatives or as relevant reference models (D-Cision, 2009): redispatch, different forms of counter trade and explicit or implicit auctions.

An important distinction can be made between those congestion management methods which assume that the network can be cleared without constraints, and then apply *ex post* corrective measures when this is not the case, and those which focus on pricing expected transmission scarcity *ex ante*. The first set of methods has been called "remedial" or (close to[8]) real time and includes redispatching and counter trading. The second category takes place in advance, and includes both implicit and explicit auctions (Knops, 2008).

Congestion management ex post of day-ahead trade: redispatching and counter trading

Perhaps the simplest way to manage congestion is to start by allowing market parties to trade as if transmission capacity were unlimited. A single marginal price for electricity is the outcome at all locations on the transmission network. In a congested network, this would result in an electricity flow across the transmission line greater than the maximum capacity. The TSO therefore intervenes, to ensure that more electricity is produced downstream of the congestion and that less is produced upstream of congestion, thus relieving the congestion. This is known as redispatching.

Counter trading is a similar form of congestion management involving bids by the generators upstream to be constrained off –allowing them to meet their obligations without running their plants. (Consentec and FrontierEconomics, 2004) Given a sufficient level of competition, this system should ensure these suppliers bid up to their avoided cost. The generator with the lowest accepted bid determines the level of payments to the TSO. The effects are thus similar to classic redispatching, but rely on a bidding process rather than the assumption of full knowledge of all marginal cost functions (De Vries and Hakvoort, 2001). Some of the current proposals which are under consideration for managing congestion within the Dutch high voltage network may be seen as being based on this method, although the details related to the implementation[9] are still under discussion at the time of writing.

Allocation ex ante of day-ahead trade: explicit auctions and implicit auctions

Methods for managing congestion in advance can be grouped into two main categories, based on whether the market clearing mechanism used is implicit or explicit (De Jong, 2009). When an implicit auction is used, the auctions for energy and transmission capacity are integrated into a single transaction and simultaneous. The market participants bid into their local power exchange, and these bids form the input for the power exchanges and TSOs involved to determine viable use of transmission between price zones. In contrast, an explicit auction features separate transactions for power and for transmission capacity.

Explicit auctions

[8] In practice, this category includes congestion management when applied after day-ahead trade has taken place, but before real time electricity generation and transmission.
[9] Particularly the allocation of the resulting costs, after counter trading has taken place.

Explicit auctions are currently used between the Netherlands and Germany to price the use of interconnector capacity. An explicit auction system will require separate transactions for transmission capacity and energy – an added complexity for suppliers of electricity, which may form a barrier to trade (De Vries and Hakvoort, 2001). Several variations of auction exist, such as pay as bid or marginal price auctions, of which the latter is most often used for electricity markets.

The advantage of such a system is that it may be relatively transparent and requires fewer institutions to administer in comparison with alternatives (e.g. organized power exchanges may be required on both sides of an interconnector for market splitting). A disadvantage is that it appears that bidding for transmission capacity and energy separately requires better information than market parties have in practice: during significant periods of time, available capacity on interconnectors appears to be used for transmission in the opposite direction to that which the actual price difference would imply is profitable. This is the case for the Dutch-German interconnectors (NMA, 2008).

Implicit auctions: market splitting and market coupling

Market coupling begins with markets on either side of a congested transmission line, which clear separately. The market operator then 'buys' capacity in the lower priced market or zone up to the full capacity of the congested transmission line, and 'sells' this in the higher priced market or zone by adding these bids there. Market splitting yields similar results, but the procedure is different as the markets are first aimed to be cleared as one before the market is 'split' into several price zones (De Jong, 2009).

If this is sufficient to equalize prices, then no splitting or congestion occurs. If this is not sufficient to equalize prices, market is split into 2 (or more) zones with prices that are brought as close into balance as is possible. Market splitting is a convenient method for market parties, who only need to bid into their 'own' markets. Bilateral contracts are difficult to honour between the two markets. In the Nordic markets where this method is applied, a strong trend exists towards financial instead of physical contracts.

The definition of the zones be used may become a contentious issue if it affects prices and results in income transfers. Jornsten and Bjørndal (2001) investigate this using a model with 8 nodes, finding that the definition of optimal zones is a delicate question. Stoft (1997) suggests that zonal boundaries should in principle reflect pricing differences between nodes. A trade-off exists, between the extent to which the zones chosen reflect price differences (improving efficiency) and the complexity of the system. Bjørndal and Jornsten (2007) suggest that having fewer, fixed price areas may reduce uncertainty and improve liquidity of the zonal markets, which contributes to the stability and predictability of spot market prices. This would allow for greater confidence in the market outcome and in the possibilities for hedging risk. A discussion of the arguments for various zonal configurations with Nordic markets can be found in (2.3).

Given the successful introduction of trilateral market coupling between France, Belgium and the Netherlands, market coupling would appear to be a likely future method for managing the congestion on interconnectors between countries in the central west European region. An issue arising with such proposals is that determining capacities to safely use in a meshed system expanding market coupling to Germany from just the Netherlands, Belgium and France remains a practical challenge (Sharma, 2007). This point is also made by Ehrenmann and Smeers (2005) when considering the method from a European perspective. While Perez-Arriaga and Olmos (2005 page 127) concur that a coordinated implicit auction could “conceptually look like an appealing proposition”, they are sceptical about whether the necessary centralization is politically feasible, and therefore suggest a hybrid system of auctions is more suited to the context of the European Internal Electricity Market (IEM).

Implicit auctions: nodal pricing (locational marginal pricing)

Nodal pricing, first discussed by Hogan (1992) is a method that allocates scarcity of transmission capacity in the network to an even higher level of detail than zonal pricing, by allowing different prices to occur at each node in the network. These nodes represent locations where power is injected or withdrawn from the grid. Each of these nodes balances separately, with its own marginal price for transmission, power production and consumption (Hsu, 1997). The system is therefore also known as ‘Locational Marginal Pricing’.

Theoretically, setting prices per node may be considered as a benchmark for short term economic efficiency (Brunekreeft et al., 2005). Calculations by Leuthold et al. (2008) for Germany and Green (2007) for the U.K. estimate welfare gains from introducing nodal prices to amount to a 0, 9% and a 1,3 % increase in welfare (i.e. social surplus, the difference between the area under the demand curve and the supply curve for electricity) respectively. By accurately reflecting costs, clear short term incentives are offered to market participants, a point strongly advanced by proponents of nodal pricing such as Hogan (1992), who suggested a complementary system of tradable transmission rights.

The drawbacks may include the complexity of performing the necessary algorithms for clearing the market and allocating capacity and prices, the perceived lack of transparency for market parties of the process leading to this pricing, the possible volatility of prices under such a changeable system (translating into uncertainty, a potential barrier to investment in generation) and the potential occurrence of localized market power due to a lack of liquidity in some of the locations. Furthermore, Brunekreeft et al. (2005) stress that by paying the marginal costs for transmission line use rather than the average cost, the transmission charges which may be paid by consumers could be overestimated during times of congestion. This may however be compensated, for example by using the surplus revenue to cover the operational costs of the network, reducing that portion of customers bills.

2.3 Criteria for policymakers

This research is aimed at investigating the issue of congestion management, applied within and between the networks of Germany and the Netherlands.

As is discussed in section 2.2, several possible alternative methods exist which could be applied to manage congestion both within and between transmission networks such as those of the Netherlands and Germany. Choosing one of these methods will require deciding which will is most suitable.

An important theoretical question related to this choice is how to define ‘suitability’. Several different criteria exist, and the parties affected by congestion management may have different opinions as to which of these should be considered most important when choosing a method. This section of the chapter will discuss possible criteria for judging suitability on the basis of the available literature in the form of academic and public documents.

An overview of all the criteria which are considered in this section is given in the table below (see Table 1). First, criteria which are difficult to assess with network models are briefly discussed. These criteria fall outside the scope of the quantitative research described in chapters three, four and five of this thesis. Those criteria which can be assessed using the quantitative model are next explained in greater detail. For each such criterion, the relevance and the way in which the impact of policy choices on it may be measured are discussed.

Table 1: Overview of criteria for congestion management methods

Criterion	Especially relevant from the perspective of:	Measurable through model outcome?
Congestion costs	Affected market participants	Yes (costs of redispatching/counter trading)
Congestion rents	TSO, affected users	Yes (difference in prices x transported power in an implicit auction)
Possibility of connecting new entrants	Potential entrants	Can be done under all CM methods
Effects on the position of market participants	Incumbent suppliers	No, unless congestion is modelled over a representative period (e.g. a whole year of trading)
Productive efficiency	Consumers	Yes (based on the change in surplus)
Market outcomes	Consumers / suppliers	Yes (prices, social welfare)
Long-term investment incentives	Suppliers and TSO	No, unless congestion is modelled over long term and investment is also modelled.
Market performance (price volatility)	Consumers/suppliers	No, unless congestion is modelled over long term, including incidental events such as equipment failures.
Market performance (transparency)	Regulator	No, (difficult to quantify)
Network flows	TSO	Yes, (quantity transported over each link the network model)
Feasibility of implementation and allocation of costs and revenues to actors	All actors	No, difficult to quantify

Criteria that are difficult to assess using network models

This section briefly discusses some criteria which may be relevant to assessing the suitability of congestion management methods, but fall outside of the scope of the quantitative research described in chapters 3 and 4 of this thesis. These aspects are considered in the interpretation of the research results and conclusions, but are difficult to assess based on network models.

Practical feasibility of introduction, the allocation of costs and revenues between actors

A first important criterion for suitability of congestion management methods is whether they can be successfully implemented in practice. As congestion management involves many actors and a public dependency on the knowledge and cooperation of parties such as TSOs (De Jong, 2009 pages 181-182), achieving political consensus for the implementation of a new method may be difficult. A trade-off can be identified between simplicity of the system used and the accuracy with which it reflects the physical complexity involved in power system operation (Uhlen et al., 2005).

Changing the way markets work when congestion occurs may require market participants to act differently, affecting transaction costs. At the regional or supra-regional level, such a policy shift may involve comprehensive institutional changes which could be even more difficult to introduce, such as a centralized auction house (Perez-Arriaga and Olmos, 2005). Although from a theoretical perspective various different forms of congestion management may be shown to change only the distribution and not the overall level of welfare (De Vries and Hakvoort, 2001), (Ding and Fuller, 2005), these redistribution effects can translate into winners and losers compared to current practice. For example, if a company owns generation capacity in a region which is often export constrained, differentiating electricity prices when congestion occurs could reduce revenue levels in comparison to a method that creates a single marginal price zone which ignores transmission constraints.

Judging the feasibility of changing current policy from the perspective of political science extends beyond the scope of this research. However, methods for congestion management which are no longer legal under EU law, such as non market-based alternatives for capacity allocation on the interconnectors between countries, are not considered within the research.

Long term economic outcomes: incentives for investment in generation and network capacity

In addition to the direct effects, congestion management may also have long-term consequences on the electricity sector. One important effect is related to the incentives which result from the congestion management for the location of investment in electricity generation. In such investment decisions both the level of revenues expected and the uncertainty involved will play a part. The pricing of transmission scarcity can serve as an incentive to producers to locate in less constrained locations. Theoretically, it could also do the same for consumers, but in practice this effect may be limited given the nature of electricity as a basic utility for most residential customers.

The other important party affected over the long term by the congestion management method is the TSO (or TSOs) responsible for operating the transmission network or networks involved. In the long term, if the costs for congestion management are paid by the TSO, it will have an incentive to invest to expand the transmission infrastructure until the costs of doing so exceed those of managing congestion. If the costs are covered in another way, then the incentive for network investment will need to be covered in a different way.

Assessing long term market development requires dynamic models including representation of investment behaviour by the relevant actors. This lies outside the scope of this research, although the differences between the pricing signals sent to market participants for any given congestion scenario can be quantified.

Effects on market operation: market power, price volatility and transparency

When congestion occurs, certain market parties may become crucial for realizing a feasible outcome as their generation may need to be constrained on or off. This may result in an increase in their market power, which could be undesirable if it offers the scope for price manipulation. At least three different potential forms of strategic behaviour can be identified (EA Energy analyses, 2007).

First, the limitation of the available supply in the market can be used to drive up prices. Second, by actively ensuring congestion occurs, competitors may suffer a barrier to entering (part of) the electricity market and prices can be made to diverge. Finally, initially bidding strategically at a price level differing from true marginal cost can be profitable, if a supplier can attain a premium for power sold under the congestion management method.

How vulnerable is the Dutch market to such undesirable outcomes? Analysis by London Economics (2007) published by the European Commission established that the level of concentration within the Dutch market was high, but much less so than Belgium and France, which were close to monopolistic. The study suggested that a mark-up occurred in price levels of around 6% compared to outcomes predicted given perfect competition. However, establishing proof of conscious abuse of market power may be more difficult than simply calculating the divergence from benchmark results.

The specific options which an individual supplier will have to operate strategically, will depend on the specific portfolio of generation available. Establishing accurate predictions for a future energy market, when mergers and acquisitions may change the generation portfolios of the different suppliers would therefore be even more difficult.

Modelling the potential abuse of market power requires more sophisticated models than that described in this thesis, which can represent the behaviour of multiple independent actors under assumptions of imperfect competition, such as Bertrand or Cournot competition. Although some research has been done in the field of energy markets (e.g. relating to trading over interconnector capacity by Hobbs and Rijkers (2004b)), this goes beyond the scope of this research.

Aside from the actual level of electricity prices, their volatility and transparency may be important. Methods involving price differentiation may make prices for electricity less stable and the process leading to their outcome less transparent than before. This would be unattractive in the sense that it may make it harder for users to react efficiently to price signals (Green, 1997). On the other hand, as Perez-Arriaga and Olmos (2005) note, European companies have argued that within smaller, disaggregated markets they could suffer from decreased confidentiality compared to larger single price areas. As disaggregating the market into price zones may influence the flows over different parts of the network, an additional effect that a congestion management method may have is to influence the network efficiency – the measure of how much capacity is used relative to the total available.

Criteria which may be assessed quantitatively using network models

This section describes the criteria for suitability of congestion management methods which may be assessed quantitatively using research based on network modelling. For each set of criteria, a brief explanation is given and their relevance is discussed. Finally, the way in which it can be measured from the model output is indicated.

Level of expected congestion rents and costs and their allocation

Real time or corrective congestion management, through redispatching or counter trading, will imply the payment of greater costs for increasing capacity downstream of congestion than the amount of revenues that result from decreasing capacity upstream of congestion.

The level of these costs and revenues indicates how much is paid for realizing the adjustments that are necessary to manage the congestion.

In the model described in chapter 3 of this research, revenues can be estimated for congestion management that involves setting a price for scarce capacity, by multiplying this by the quantity of power transported over the congested transmission link in question. When corrective methods such as counter trading are applied to deal with congestion within an area with a single price for electricity, it is possible to calculate the necessary increases by generators in capacity dispatched downstream of congestion (which must be paid for at the level of the market price) and the reductions in capacity dispatched by generators upstream of congestion (which will be prepared to pay up to their variable costs to avoid production). The difference between these two will indicate the costs congestion management of counter trading.

Short term economic outcomes: productive efficiency, prices and welfare

When a congestion management method is applied, the market may be divided into regions with differing prices (in the case of zonal or nodal pricing) or other suppliers of generation may be dispatched than a spot market outcome disregarding transmission limitations would suggest (in the case of redispatching or counter trading). These direct economic effects can be related to the economic conception of social welfare as the sum of the producer and consumer surplus from the operation of the electricity market.

An important question is in what measure the application of the methods affects the productive efficiency of the market, for example by reducing welfare outcomes by leading to the dispatch of units that do not have the lowest level of marginal costs. An important related issue is the effect congestion management has on the price of electricity. Methods which are based on pricing scarce transmission capacity will result in differing prices per region depending on the way in which the market is disaggregated when congestion occurs. Although the day-ahead trade modelled is closer to the wholesale rather than the retail market, structural differences in prices are likely to be passed on by suppliers to electricity consumers, affecting them positively or negatively depending on where they happen to be located. This differentiation could be politically sensitive.

The model used in this research calculates the social surplus resulting from a market outcome by subtracting the costs of production (the area under the supply curve) from the willingness of electricity consumers to pay for electricity (the area under the demand curve). The relationship between the quantity of electricity consumed and the price paid is indicated by the demand curve for electricity. The flows are calculated based on the dispatch of power plants and the relevant physical laws.

Conclusions: methods for congestion management and criteria for judging their effect

This chapter has considered the policy framework for decision makers related to congestion management. It is clear from the literature that several different methods are possible, and that the diverse set of potentially relevant criteria will ensure that trade-offs will be involved between goals. The methods applicable for congestion management between European countries are limited to market-based methods such as implicit auctions. Methods which are currently practiced or feasible for managing congestion within the Dutch network during the period before 2014 include both *ex ante* methods, such as explicit and implicit auctions, and *ex post* methods such as redispatch and counter trade. The latter are, although no final policy decision had been taken at the time of writing.

The research described in chapters three and four of this thesis concerns the application of a model of the electricity markets and transmission networks of the Netherlands, Germany, Belgium and France. The research aims to investigate the suitability of congestion management using price zones for congestion both within and between the Netherlands and Germany.

Many criteria exist which may be relevant for judging the suitability of congestion management methods. The model which is described in chapter three of this research can be used to calculate the social surplus resulting from electricity trade, an indicator that includes the benefits of both suppliers and consumers. Furthermore, the cost of congestion and the resulting prices of electricity can be derived from the model output. The flows through the network may also be estimated. However, it is important to remember that other aspects such as the longer term behaviour of actors and the abuse of market power are difficult to capture using simplified representations of markets and electricity networks.

2.3 *An international example: congestion management in the Nordic markets*

In sections 2.1 and 2.2 of this chapter, the criteria through which the suitability of different congestion management methods may be assessed and the differences between those alternatives are discussed. Chapters 3 and 4 of this thesis describe the methodology and results of a quantitative analysis of a number of these alternatives for managing congestion within and between the Netherlands and neighbouring countries. This section discusses what can be learned from existing international practice, by focusing in particular on congestion management within the Nordic markets.

As is noted elsewhere, certain criteria for suitability of congestion management methods are difficult to assess based on models which necessarily make assumptions that simplify reality. Most notably, congestion management can affect aspects of market performance such as price volatility and potential market power and can help to influence long term trends such as investment choices in the behaviour of actors in the market.

Investigation of international practice in congestion management may therefore form a worthwhile addition to the quantitative research by giving an indication of the outcomes of established forms of congestion management. It can also help understand which policy choices remain politically controversial, even when a market-based approach such as market splitting is agreed upon within a region. On the other hand, it is important to remember that the way electricity markets in different regions work is strongly influenced by the specific nature of the local physical and institutional context (De Vries and Correljé, 2008).

This section therefore begins with a brief explanation of congestion management within the context of the Nordic markets. The functioning of the market and long term investment in generation and transmission are then discussed within the context of congestion management. The section concludes with an overview of three policy issues specific to congestion management that have proved controversial within the Nordic markets, in order to give an idea of the way in which the complex trade-offs involved in changing such policies play out in practice.

Congestion management within the Nordic markets

Electricity policy within the Nordic countries forms an interesting case to study because of the scope of regional market integration and the length of experience with a market-based method for congestion management. Norway was one of the early examples (1991) of a country opening up its electricity market. International trade began in 1996 when Norway and Sweden established the common electricity market and power exchange, Nordpool (Nordpool website, 2009). Although the exchange was initially owned by the TSOs of Norway and Sweden and covered these markets, it has since been expanded to include first Finland and western Denmark, and then eastern Denmark (1998 and 2000) (Gjerde et al., 2005). The most recent expansion was to have improved congestion management on the interconnectors with Northern Germany through market coupling, but trading was suspended 10 days after introduction in 2008 because “. . . the complexity of volume coupling was clearly underestimated in the design and testing process. The parties had to return to the design table to be fully able to replicate the optimization constraints in the Nordic region". (Nordpool, 2009a page 6)

While Nordpool is the sole market operator, there are separate regulatory authorities and TSOs in the participating countries. All the countries involved have chosen to implement TSOs, which despite some differences share similar objectives and basic functions (Gjerde et al., 2005). These are publicly held, with the exception of the Finnish TSO which is partly owed by generation companies(Nordic Competition Authorities, 2007). The TSOs have signed a system operation agreement covering congestion management , but also other aspects such as reliability, operation limits, outage coordination, ancillary services, emergency operation, balance operation, power exchange, information exchange (Flatabø et al., 2003).

Two of the methods discussed in section 2.3 are used for congestion management within Nordpool: market splitting and counter trading. Market splitting is generally used to manage congestion between price zones (called bidding areas in Nordpool - see figure 2 for one combination of possible areas) through the trade within the day-ahead spot market. Market parties that have bilateral contracts spanning bidding areas must sell the energy in the supply area and purchase it in the load area, to account for the consequences of congestion and expose the contracts to the consequences. This is the only mandatory participation in the spot market (Kristiansen, 2004).

When the initial power flows resulting from clearing the market exceed transmission limits, flows between price areas are constrained according to physical capacity limits and a new market outcome with different prices in the various price areas can result. In this case, a higher price will increase the level of power generation dispatch downstream of congestion and a lower price will decrease it upstream. The market process during periods of potential congestion can therefore be seen as an implicit auction for transmission capacity between price areas using the bids of the market parties.

Where this process does not alleviate congestion (i.e. when congestion occurs within the price areas), counter trading is applied by the TSO responsible within that area. This is done within the areas with only the resources available there, after day-ahead market trade has taken place. Where these resources are not assumed to be adequately available, reductions in border interconnection capacities declared are applied before market trading. Balancing is also done within national areas continuously. Counter trade has been used within bidding areas and for corrective real time congestion management (based on the regulatory market). Norway and Denmark have until now been the only Nordic countries to apply several differing bidding areas within their national borders[10] (Amundsen and Bergman, 2006).

[10] Some markets for electricity in the United States, New Zealand and within Europe, Italy have also allow differing prices within their borders when congestion occurs.

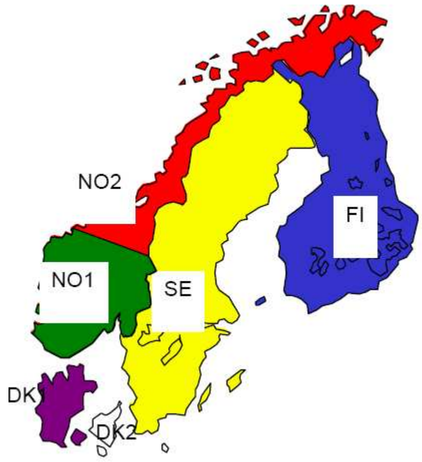

Figure 2: Typical zonal configuration for Nordpool

Costs for managing congestion are mainly related to counter trading, which occurs most often after transmission capacities have been reduced due to unexpected outages or forecasting errors. NordReg (2007) gives the figures for the level of counter trading costs in the region between 2001 and 2005. Total costs for this period varied between 2 and 26 million euro.

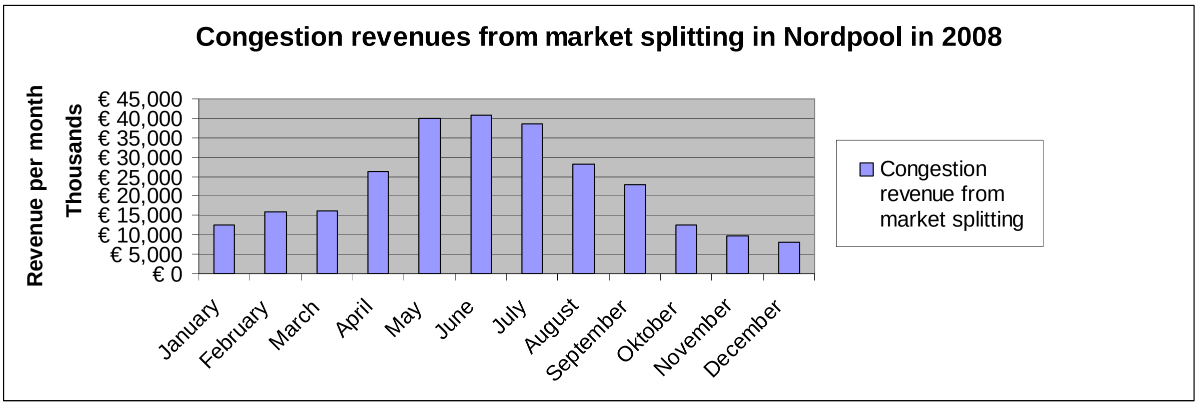

Figure 3: Congestion revenues from market splitting in Nordpool in 2008 based on data in (Nordpool, 2009b)

Revenue data for market splitting are available for the last two years from Nordpool. Revenues are volatile, depending on hydrological conditions and the level of imports from and exports to the continent (see figure 3 for an example of the spread over a calendar year). According to Togeby et al. (2007) they usually vary between €25-100 million Euros per year, but were high during the past few years because of higher prices.

Market performance

Does this combination of congestion management methods help or hinder the ability of the Nordic markets to deliver competitive market outcomes? Scientific research and investigations by market regulators have focused on two issues within the context of congestion and market integration: price volatility and concerns related to market power.

Simonsen (2005) suggests that the Nordpool spot market for the twelve years before 2004 was more volatile than financial markets. Nevertheless, Nordpool is “known for its low volatility” (compared to other deregulated power markets) and the author notes that higher volatility in summer months may be due to the occasional occurrence of forced hydropower production in order to prevent flooding, rather than congestion management practices. Amundsen and Bergman (2007) explain that a strong correlation exists between hydrological conditions and power prices. ‘Wet years’ such as 1997-2000 exhibit lower prices than dry years, with the winter of 2002 / 2003 seeing rarely occurring conditions with very low reservoir levels resulting in an effective supply shock to the market.

In figure 4, which is based on Nordpool data and included in a report by the Nordic Competition Authorities (2007), the price for different areas is given between 1998 and 2008. The blue lines are inserted to indicate the structural increase that the authors suggest has taken place. Although differences in prices between bidding areas can be large incidentally, in general the structural behaviour is clearly strongly related. Nordpool’s prices following the various steps integrating new markets have been studied based on empirical data by Lundgren et al. (2008). The authors conclude that both prices and volatility increased following integration of Finland. They suggest that demand within Nordpool was quite close to full supply capacity once Finland joined, and that shocks in the market therefore often moved the intersection between demand and supply into the steeper section of the supply curve (resulting in price jumps). Prices remained high following admission of Denmark, but volatility decreased. Although it is difficult to draw comparisons due to the lack of a counterfactual with a different congestion management method, the work by these authors suggests that other factors such as the margin of available supply may offer a direct explanation for much of the price volatility shown in the last few years in the Nordic markets.

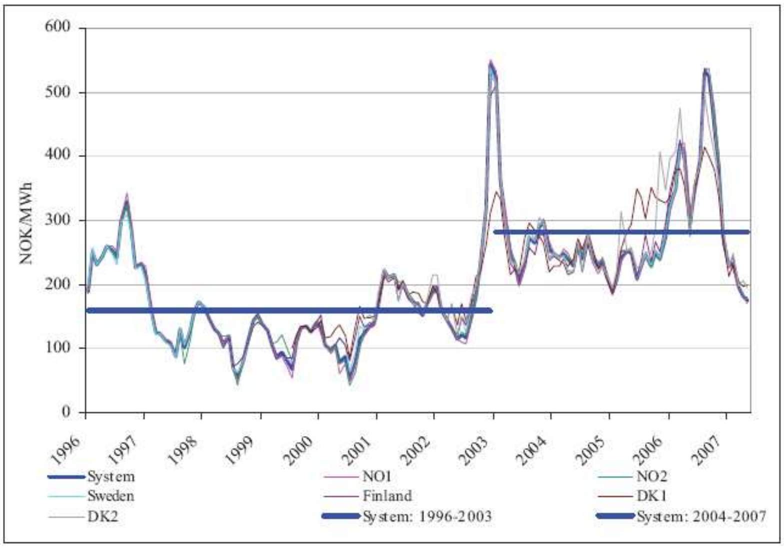

Figure 4: Nordpool electricity prices between 1996 and 2007, per bidding area (Nordic Competition Authorities, 2007 page 16)

Despite the relatively close correlation of prices in the bidding areas, risks related to price differences between them remain. Risks related to price differences between areas are especially relevant for market parties that trade across them. This has lead to the implementation of financial products known as CfD's (Contracts For Differences) which in theory allow for hedging of price differences (Kristiansen, 2004). Such instruments can help in hedging price volatility, but additional Financial Transmission Rights (FTR's) would be necessary in order to do the same for congestion costs (Togeby et al., 2007). However, Wangensteen et al. note (2005) that as this market has not been fully liquid electricity retailers may still be negatively affected.

Studies by the market regulators Nordreg (2007) show that some combinations of bidding areas may have a higher market concentration than when they clear separately, such as Finland and Sweden and Southern Norway and Denmark. In fact, as each bidding area will form part of different such combinations, the level of market concentration will differ during any single year. Calculation of a time weighted HHI[11] revealed that in fact, all bidding areas surpassed the 1000 benchmark for moderate concentration (EA Energy Analyses et al., 2008 page 45)

A more specific index than the HHI mentioned earlier is the Pivotal Supplier Index (PSI), which indicates if the capacity provided by a supplier is necessary to be able to meet demand during a period of time. Attempts have been made to calculate this for five leading suppliers in Nordpool, within separate bidding areas. As with the HHI, the values vary between zones but are generally quite high within zones (e.g. one company was pivotal within both the Finnish and Eastern Danish zones for over 50% of the time) and are lower for the market as a whole when it is integrated. Nevertheless, when there is no congestion, one of the companies is still calculated to be pivotal for as much as 18% of the time (EA Energy Analyses et al., 2008).

Specific studies by Bergman et al. (2002) carried out for the period of 2000-2001 (when a sharp increase took place in prices) and by Amundsen and Bergman (2006) for the period of 2002-2003 (when low hydropower capacity lead to a supply shock) suggest that in neither period, prices deviated significantly from predictions according to the output of a model based on perfect competition.

Olsen et al. (2006) looked specifically at market power within the West Danish bidding area during this year within the context of market coupling, noting that the specific market structure of this area contributes to decreased uncertainty for the dominant generator, which could conceivably attempt to keep the price high and separate from the Nordpool reference price when this is low, or integrated and thus higher when it is constrained. Comparing data for a week with tight conditions and normal conditions, they find: "there is no simple conclusion . . . prices in the normal week correspond best to the market power scenario, whereas prices in the tight week correspond best to the perfect market scenario". In following years, the Danish competition authority (2007 page 25) conducted investigations into price formation in the bidding area in West Denmark 2003-2004 and 2005-2006, finding that Elsam

[11] The HHI index gives an indication of market concentration; it is calculated by summing the square of the market share of companies in the market, with a benchmark of 1800 or over being seen as a high concentration and 1000 or less as low concentration.

was indeed able to use a dominant position in West Denmark to increase prices during periods of transmission scarcity in both cases.

The issue of market power was also investigated by Johnsen (2001), who specifically looked at time periods when constraints were binding and bidding areas internally separated the Norwegian market for the years between 1996 and 1998. They found that "suppliers within Kristiansand[12] are consistently marking up prices more when demand elasticity is low and constraints are binding" (Johnsen et al, 1999 page 45) for periods during the night. These authors note that this is the only area where Stattkraft, the state-owned incumbent within the Norwegian national market, is not one of the four largest producers.

It may be concluded that the fact that congestion management can effectively split markets could affect the level of concentration. However, it should also be noted that the concentration in market structure referred to in the Nordic markets was generally already in place before market integration and the introduction of the current congestion management regime.

Long term influences on investment in transmission and generation

The short term economic consequences of congestion management are clear. However, a relevant question is whether these effects will translate into trends that can be distinguished over a longer timeframe. In theory, pricing transmission capacity should allow for clearer indication of the value of congested transmission lines, and also send signals about where to locate cheaply which generators may take into account in their investment decisions. Is this what actually takes place in the Nordic markets?

The Nordic TSOs cooperate strongly within the joint body Nordel, that serves as a forum for contact and co-operation. Their intention to "act as one Nordic TSO and be the basis for a harmonized Nordic electricity market" has been made explicit (Jacobson and Krantz, 2005 pg1). In the past, transmission planning was done nationally, where the investment decisions are taken, but it is becoming increasingly based on regional coordination through Nordel.
A master plan for the regional grid was published in 2008 (Dovland, 2008). The plans include strengthening connections that fall within areas which are the sole responsibility of one TSO, and focuses on 'channels' or combinations of transmission links which may experience congestion.

Significantly, during the last few years congestion management revenues have been allocated proportionally based on the investment needed to realize these transmission expansion plans. The organization explicitly includes transmission pricing, coordination of grid investments and congestion management among its tasks, and has set up working groups in the past to look into specific policy issues related to congestion management.

[12] The southernmost of the bidding areas within Norway

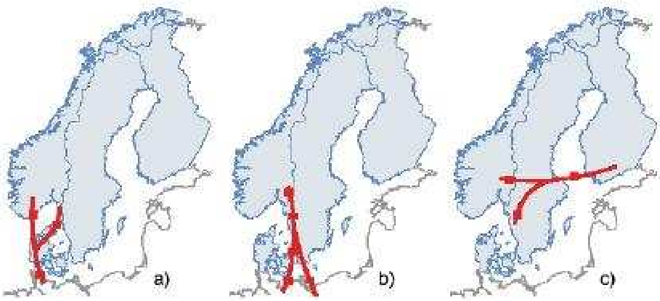

Figure 5: Congested transport channels within Nordpool (Jacobson and Krantz, 2005)

The importance of such joint network planning specifically in order to prevent structural congestion and insufficiencies in the infrastructure has now been recognized by joint institutions such as the Nordic regulatory authorities (2007) and competition authorities (2007). It may be concluded that increasing cooperation has allowed for a somewhat more coordinated approach to investment in transmission capacity. The fact that this investment is financed by congestion management revenues reflects the recognition of the mutual interdependence of the interconnected transmission networks.

A study aimed at quantifying the effects of different price zone configurations (EA Energy analyses, 2007) for the Nordic council of ministers looked at the scope of the incentives for investment in electricity generation offered by locational signals. The authors suggest that in theory ". . .even if average prices are quite similar there will be time segments with very different prices depending on the chosen CM method. Such time segments can be valuable market-based incentives for investments if they are frequent enough, or for activation of potential resources on the demand side."

However, the simulation results in the study (EA Energy analyses, page 77) suggest that of the four additional new price zones investigated in the study, only one results in an average spot price difference higher than 0,1 € /MWh. The remaining additional area is 0,8 € /MWh. The authors reflect that "Even such a difference is relatively small compared to all other differences and difficulties . . characterizing possible investment alternatives.

It may be concluded that while congestion management methods such as zonal pricing offer the prospect of increased efficiency in resource allocation through price signals to investors in electricity generation in theory, these signals may often be too small to outweigh other potential cost drivers in the decisions taken in practice.

Proposals for changes in policy and their political feasibility

Assessing the feasibility of changes in policy implies difficult tradeoffs, taking into account both the level of the effects on the various other criteria mentioned within this chapter, the changes a new policy would bring, and the arguments brought forward within a debate by the various actors with an interest in the electricity market.

Three issues within the Nordic markets can be seen as a good illustration of the difficulty of making these types of policy decisions. First, the question of how to determine the necessary price zones or bidding areas used to manage congestion has provoked considerable debate among the countries and actors. Secondly, the question of whether the application of counter trading to maintain larger market areas is desirable has been answered differently by the countries and actors. Finally, the practice of limiting interconnection capacity between price zones to prevent the congestion management has been controversial. This section concludes by discussing these issues.

In general, economic theory suggests that introducing more specific allocation of scarce transmission capacity through methods such as nodal pricing and implicit auctions can lead to efficient locational incentives for investment if the TSO accurately forecasts the load. The scarcity of transmission is reflected can then be reflected in lower prices in export-constrained areas and higher prices in import-constrained areas (Brunekreeft et al., 2005). However, this does not mean that a choice for multiple, smaller price zones is either unambiguous or uncontested. As was noted in section 2.2, operating a market with the highest level of geographic disaggregation through nodal pricing increases the complexity to the activities involved in managing the electricity grid and market - already a complicated exercise due to the physical characteristics of electricity networks noted in Chapter one of this thesis.

Another concern related to smaller zones, is that the effective size of the wholesale electricity is limited for retailers which are not vertically integrated[13]. Although in practice it is the physical limits of the network which impose limits to trade and thus imply market concentration within specific areas, electricity retailers are judged to be (currently) less able to hedge for the resulting price differences and congestion costs. Thus, a 2007 rapport by Swedish market authorities, market participants and the Swedish TSO (2007) stressed the importance of a Nordic rather than a national perspective, and of as few and large bidding areas as possible. As long as the retail market is a national one, the rapport suggests divisions will impair competitive conditions, despite the fact that more efficient use of resources may be achieved.

A second consideration relates to the question of why, where and how often congestion occurs. Within the Nordic markets, a large share of power production in wet years comes from hydropower capacity in the north of several countries, which strains the transmission infrastructure between these regions and the south. This perspective lead the Swedish market authorities, market participants and the Swedish TSO to the conclusion that the implementation of cross border areas reflecting the structural congestion boundaries related to these resources in the north of Sweden, Norway and Finland may be a better idea than maintaining the larger current national market (Energy Markets Inspectorate et al, 2007).

A problem with such considerations is that these aspects may change over time – hydropower is not in abundance every year, and transmission capacity constraints may be alleviated by new investment or by the effects of gradual changes in the location of electricity demand and supply. For example, because of investment within Finland on North-South transmission and the growth in demand in the North, structural congestion is no longer expected to occur within

[13] The fragmentation of the market may according to Bjønrdal and Jornsten (2008, page1988) 'result in low volumes and ill-liquid geographical markets. This has been proposed as arguments against both the zonal . . . and a fully developed nodal pricing system'.

the Finnish network but rather appear on interconnectors during situations when that country imports power. (NordReg, 2007) During situations in which Finland exports power, limitations within the Finnish grid between North and South may now need to be imposed, but there is a lack of suitable generation to be used for counter trading. Thus, capacity is reduced on the interconnectors instead. Smaller price zones in this situation are not expected to lead to more efficient network use or electricity production. However, NordReg (2007) also note that introduction of market splitting in Sweden may interact with this behaviour on the Finnish grid and market, and taking this into account may lead to different conclusions.

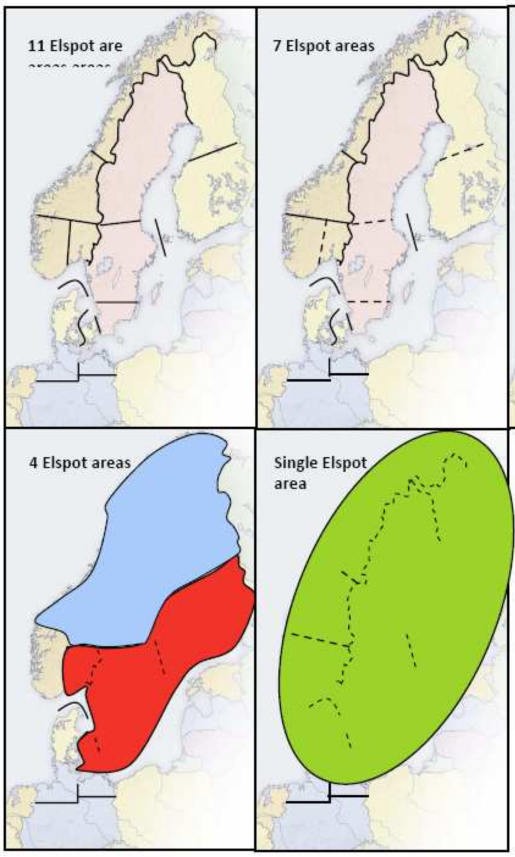

Figure 5: Zonal configurations proposed by various actors for Nordpool

Figure 5 shows various zonal combinations that have been proposed during the pas decade, which were investigated based on predicted developments for 2015 by a joint study organized by the Nordic council of ministers[14]. The 11 area case gave the most beneficial economic outcome (30 million euro higher annual welfare), but the Nordel 4 zone proposal reflecting structural congestion was very close (27 million euro higher welfare) while using improved counter trade through Elspot was also already a significant improvement (19 million euro) compared to the base case (assuming transmission capacity reduction on borders). Although such a joint exercise can inform the parties as to the validity of arguments suggested

[14] the 4 and 6 zone configurations reflect the Swedish proposal and the Finnish counter proposal mentioned in the paragraph above, while the 7 zone proposal reflects the base case as it is now and the 11 zone configuration would be the greatest disaggregation compared to current practice.

beforehand, it will not in itself resolve the conflicting interests that lead to debate concerning policy choices.

A second related controversial issue is whether counter trading should be applied actively to prevent congestion from leading to market splitting. Using counter trading to resolve congested interconnectors may not result in prices reflecting the true (marginal) cost of using scarce transmission capacity. According to the Nordic Regulatory Authorities (2007) it can also have negative consequences for system reliability. Nevertheless, an advantage can be that doing so ‘frees up’ more capacity for cross border trade and allows market ‘integration’ for a greater share of the time – also potentially reducing risk of price volatility mentioned earlier for market participants. This was a reason for some actors to propose more pro active use of counter trading on transmission lines between bidding areas within Nordpool (Lommerdal and Soder, 2004). One concept investigated by Gjerde et al. (2005) is increasing trading capacities through counter-trade is to guarantee a minimal level of capacity availability to the market. In addition to the negative effects for investment of not sending the most precise incentives to market parties, another negative consequence of such a system lies in the fact that the least cost generation capacity will not necessarily be used – thus the result is an inefficient market outcome.

In 2003, a working group was created by Nordel specifically dealing with the issue of congestion management, which aimed to realize “further Nordic harmonization of rules and practices for congestion management and a socio-economic efficient utilization of the transmission grid within and between the countries” (Gjerde et al., 2005). The group studied increased counter trade, including two situations in which either 70% of NTC or 100% of NTC ‘guaranteed availability’ would be ensured for the market transactions, using counter trade to compensate for the presence of a lower amount of physical capacity.

The results reported by the working group suggested that the time in which the Nordic area maintains a single price could increase by around 1000 and 2000 hours respectively, while differences between system and area prices would be reduced by 10% and 20% (Gjerde et al., 2005). However, it was also noted that counter trading would never fully prevent separate price areas, and that for some areas even maintaining 50% of NTC capacity would be “*demanding*” from a cost perspective.

Table 2: Simulated cost of guaranteeing interconnector capacity at different levels of NTC using counter trading, data from (Gjerde et al., 2005)

	Cost at 70% of NTC	**Cost at 100% of NTC**
Wet year	12,5-20	60-90
Dry year	30-45	125-200
Fall in CM rents from market splitting	Up to 15%	Up to 60%

A normal year will have lower costs than a wet year. The average net cost of counter-trading varied in the simulations between 6 and as much as 30 Euro/mWh. The working group concluded that “a limited increase of counter-trade in the planning phase is feasible for temporary congestions in order to reduce the area price risks for the market players” and that

Nordel should consider its use mainly to prevent reductions in cross border capacity due to maintenance (Gjerde et al., 2005).

Comments on the study were solicited from market participants. Two different responses predominated: around 40% supported the use of counter trade in the planning phase, while 60% thought it should only be used for short term reductions in trading capacity. No full consensus exists on the issue: in the Director General's statement in Svenske Kraftnet's most recent annual report (2009 page 8), it is noted that there is a trade-off between the maintenance of larger bidding areas from a competition perspective and signalling resource conflicts through differentiated prices and that "among Nordic operators, there are different opinions regarding which methods should be applied."

A final issue that has provoked disagreement is the practice of reducing the estimates of safely usable interconnection capacity between countries to prevent internal congestion management.

Market splitting within the region results in congestion rents, while performing congestion management using counter trading costs affected TSOs money (De Vries and Hakvoort, 2001). This combination of congestion management methods within a region can therefore lead to incentives to avoid the latter by reducing the former, by declaring reduced transmission capacity limits between the areas. This is an important contributor within Nordpool[15] to the fact that declared transmission capacity has been reduced, although some parties involved maintain that reductions in capacity between areas is due to "security of supply" reasons (Togeby et al., 2007 page 61). A recent study suggests that, on average, transmission capacity availability on the interconnectors was as low as 75 % of the full capacity (Togeby et al., 2007). The practice was recognized in 2004 by the working group on congestion management as an issue to be addressed (Gjerde et al., 2005).

In 2006, an organization for Danish energy companies supported by the Norwegian energy association filed a complaint at the European level against the Swedish TSO alleging that the latter applies this practice to lower counter trade costs in Sweden, thus damaging competition and trade within the internal market, particularly in southern Sweden and eastern Denmark (Nordic Competition Authorities, 2007). Stakeholders in a more recent study (Togeby et al., 2007) confirm that counter trade is "not the best way to handle structural congestion" that current practice is "not transparent", does not yield "true prices" and induces "unnecessary price fluctuations".

However, the reduction of capacity between price areas may be a necessary option of last resort when resolving internal congestion using counter trade is difficult to do (due to lack of available, suitable bids) or when problems between countries arise which cannot be solved using market splitting. For example, problematic loop flows are assumed to be a reason for frequent limitation of capacity between areas in middle and southern Norway (Nordic Regulatory Authorities (NordReg), 2007). It may not be easy to distinguish such cases from

[15] It occurs regularly within Norway (to deal with congestion in the area west of Oslo), in Sweden (to deal with congestion in the middle and south of Sweden) and Finland (to deal with congestion between north and south Finland) (EA Energy analyses et al, 2008)

purely strategic behaviour. Since march 2007, TSOs have therefore been obliged to publish a code indicating the reason for reduced capacity (Togeby et al., 2007). This does not (yet) stretch as far as the data and models on which the decisions are based.

Research by Bjørndal and Jornsten (2008) has been done to quantify the consequences of several price zone configurations and plausible congestion scenarios, as well as the costs resulting from the use of capacity reductions on the interconnectors between countries to prevent counter trading. They conclude that the differences in congestion costs between fewer (national) price zones and nodal pricing may be large, it is often possible to attain a solution close to the optimal result using relatively few areas. Their research (2008, page 1987) also indicates that the costs of ‘indirect’ congestion management through transmission capacity reductions on the borders is very expensive in terms of social cost.

These results are especially interesting due to the similarity between the situation described and that which the CWE markets are moving towards: a system that uses implicit auctions (market splitting or coupling) to allocate scarce interconnector capacity between several national markets which solve internal constraints using counter trading. The part of this thesis (see Chapter 4) analyzing the results of the quantitative research therefore reflects on how the findings relate to these conclusions.

2.4 Conclusions

A brief case study focusing on the practice of congestion management in the Nordic markets goes some way towards closing this gap. The experiences in these markets indicate that the introduction of market integration and congestion management on a regional level is not likely to end disagreements between actors and policymakers on how to balance complicated goals such as the need to prevent the abuse of market power, to offer the sufficient and incentives for long term investment in both transmission and generation of electricity and to further integrate existing national markets.

Although the term ‘congestion management’ refers to a broad set of policies, the Nordic case suggests that even when only a limited number of these are applied, the disagreements over how to do so can be significant. The improved regional coordination in transmission investment, and the cooperation in research aimed at generating improved knowledge to inform such judgments suggest that it is possible to look beyond national boundaries when implementing congestion management. Furthermore, the legal proceedings brought by the European Commission against the Swedish TSO’s reductions in cross-border capacity may soon settle the question of whether this is acceptable.

The results of research by Bjørndal and Jornsten (2008) suggest both these reductions of interconnector capacity and maintenance of national price zones imply greater social costs of congestion than necessary. The authors calculate that a result close to the nodal pricing benchmark can be achieved using price zones within and between countries. These findings could provide relevant lessons if comparable effects can be predicted to occur within the CWE, suggesting that greater coordination and price zones within countries may allow for lower social costs of congestion. The research described in chapters three and four of this thesis aims to quantify the economic outcomes of different congestion management methods for the CWE region.

3 Model scope, methodology and underlying assumptions

Chapter one of this thesis introduces the issue of congestion management and explains its particular relevance with regard to the markets for electricity, and the transmission infrastructure which is used to transport it. The second chapter provides an overview of the relevant policy framework, including the legal framework, the possible methods with which congestion can be managed in theory and relevant criteria for comparing the suitability of such methods. The central contribution of the research described in this thesis is based on a quantitative analysis of congestion management through zonal pricing within and between the Netherlands and Germany.

This chapter describes the model used to generate the results of that analysis. Any such model is by definition a simplification of reality. The occurrence of congestion within the electricity transmission network and its management involve both the operation of the physical infrastructure and of the electricity markets that drive our need to use it. Representing these complex and large-scale technical and socio-economic systems involves trade-offs between the accuracy of the results and the resources available for the research in question. The research described in this thesis builds on a number of important assumptions, with which a balance between these two factors has been sought. These assumptions, and the methodology involved in building the model, form the subject of this chapter.

More specifically, the first sections (3.1 and 3.2) introduce the purpose of the model, its scope and the form of the relevant mathematical equations. Section 3.3 explains the most important methodological assumptions related to the way in which the electricity market is represented. The next section (3.4) does the same for the transport of electricity over the transmission network. Finally, sections 3.5 and 3.6 of the chapter conclude, by discussing both the sources of data used as input for building and running model and by reviewing the inherent threats to the validity posed by the uncertainty present in such data. This section also contains an analysis of the sensitivity of the model to changes such as variations in the parameters and gives an overview of the way in which scenarios are used to deal with the uncertainty involved in the research.

3.1 Purpose and overview of the model

This chapter describes the methodology and assumptions involved in building a model which is used to quantify the results of different methods for managing congestion. In order to give a better understanding of how the model works as a whole, a schematic overview is first presented in this section. It is important to note that the goal of the research is to give an indication of the behaviour of the markets and network in a general sense given such methods, allowing for insight into the relevance choice between policies, rather than the precise calculation of either electricity flows or exact market prices.

The model should therefore be considered to be a policy support model, aimed at identifying the order of magnitude of electricity costs and quantities produced and transported aided by simplified representations of both the technical and economic systems involved, rather than an attempt at precise forecasting in either field. The purpose of the model is to inform policymakers by identifying the scope and direction of potential changes in the minimal social costs of electricity provision and flows through the network, that result from differing congestion management methods.

Congestion occurs when the physical infrastructure limits market parties in transport and therefore trade in electricity. Differing congestion management methods deal with this in different ways, by adjusting either the quantities or the prices of electricity produced. The model uses linear mathematical functions for supply and demand of electricity, and finds the highest value for the benefits that could result from trade, taking into account the limitations of the network and the method used to manage congestion. An overview of this process is given in Figure 6.

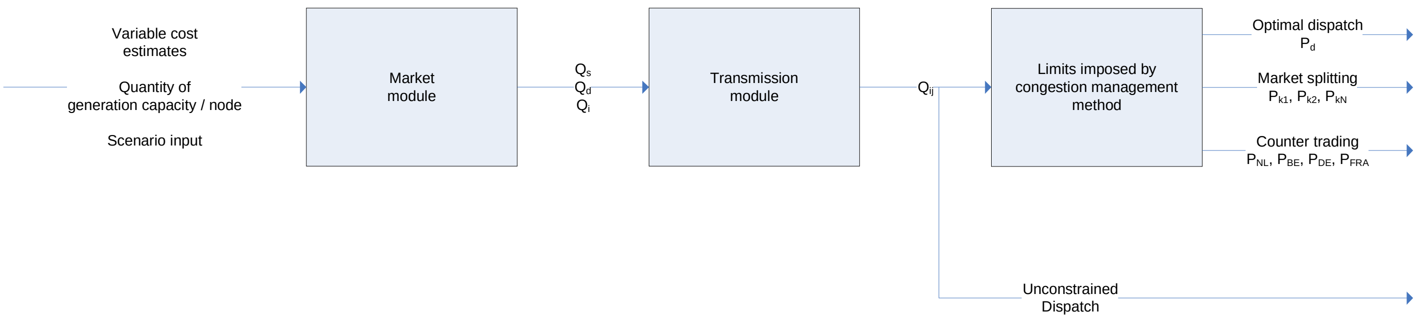

Figure 6: Overview of model for assessing congestion management methods

The model optimizes the quantities of electricity to produce at each node and transport elsewhere by calculating the area under the demand curve and the supply curve for all the nodes, in what is identified in the academic literature by authors such as Smeers (2008) as a Consumer and Producer Surplus Maximization Problem (CPSM). The price of electricity at each node is determined by the intersection of the supply and demand curves, as this is the point where the social surplus is greatest, although importing or exporting power will affect the position of this point (see e.g. Figure 7, for an exporting node). Trade between different areas allows electricity supply from one node to be consumed in another place. As the costs of production are dependent on the type and amount of generation capacity, these differ between the nodes, making trade profitable.

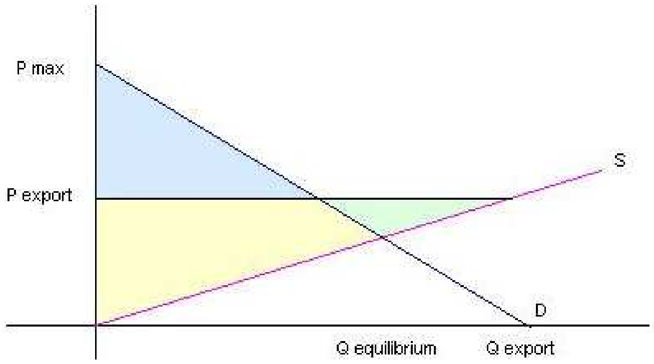

Figure 7 : Demonstration of supply and demand curve at an exporting node

The incentives for trade are largest for situations such as those involving large wind capacities. However, trade is limited by the fact that electricity can only be transported between places through the infrastructure of the transmission network.

The model therefore calculates the flows through each link of the network in accordance with the physical laws. Significantly, Ohm's laws ensure that the size of such flows between any two points is determined by the impedance of the different routes the electricity can pass through. Figure 8 shows a simple example network with equal impedances for each line, where the flow from node 1 to node 3 divides over two routes in inverse proportion to their impedance. Furthermore, the model takes into account the capacity limits of each component.

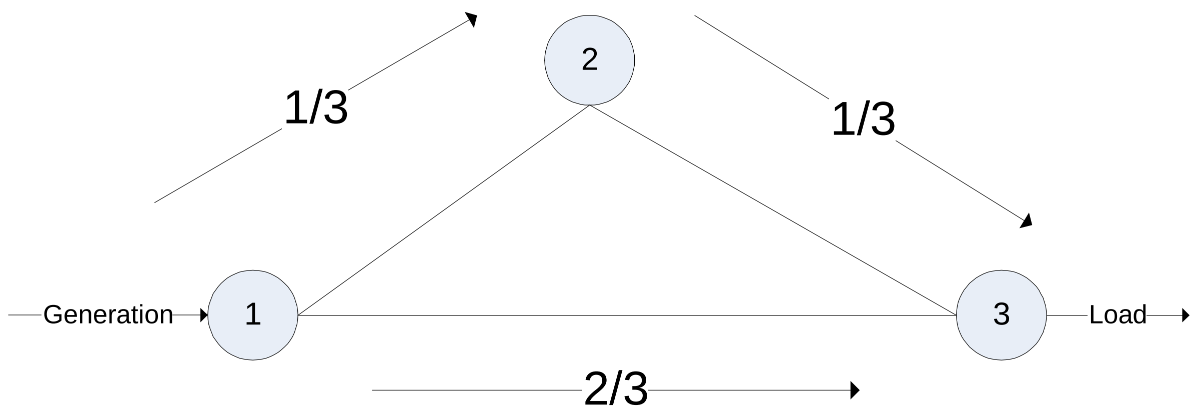

Figure 8: Simple network diagram illustrating effect of physical laws on flows through a network

If transmission is unlimited, then trade will allow the price to be the same in each node. If transmission is limited, then the optimal solution found by the model would allow prices to differ between nodes (clearing the market in this way is known as nodal pricing (Hogan, 1992). However, because electricity market institutions are currently organized along national lines, the result of electricity trade at the power exchange is a single national price. To maintain this national price zone under congestion, the market operator can intervene by ordering capacity to be increased downstream of congestion and decreased upstream of it (this is known as counter trading). The model can represent this form of congestion management, or other price zones, by constraining the prices within such a zone.

3.2 Scope and structure of the model

This section of the chapter describes the geographic and temporal scope of the model, and introduces the general mathematical form of the equations of which it consists.

Determination of the level of detail of the geographic scope of the model involved a trade-off between improved accuracy and the resulting model complexity. The scope had to include sufficient nodes, representing points where electricity is generated or consumed, to allow the most important congestion effects to be modelled. The actual grid map, issued by the TSO (Tennet, 2009c) shows tens of nodes in the actual Dutch grid (see Figure 9).

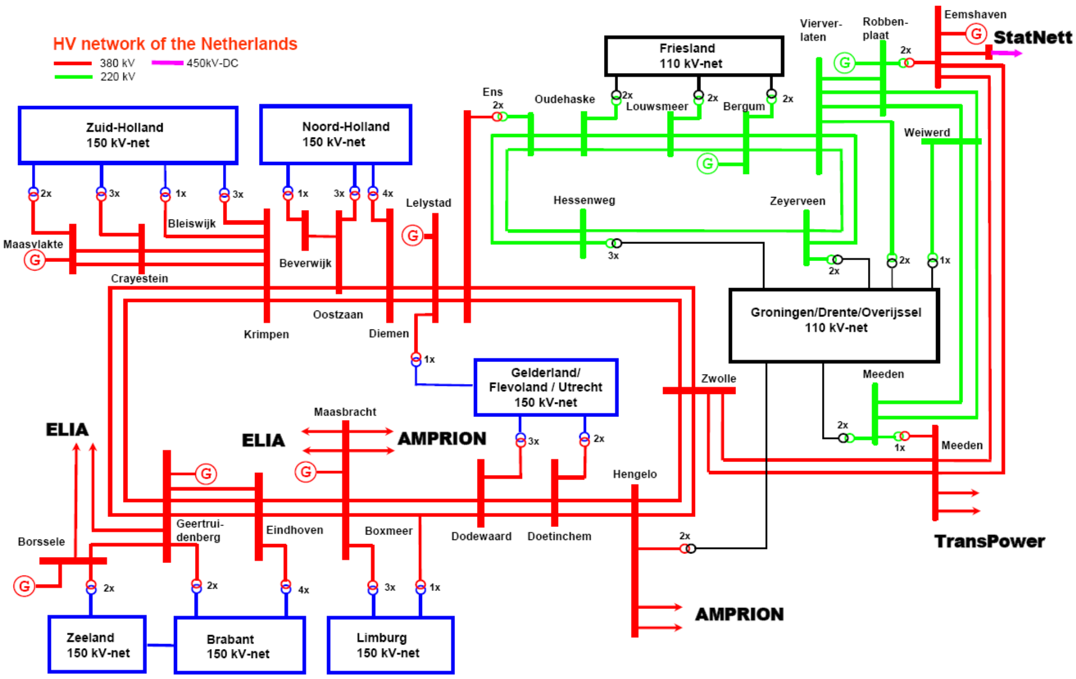

Figure 9a: Grid map of the Tennet 380 kV and 220kV high voltage grid (source: Tennet (2009), reproduced with permission)

Academic studies often approximate this using far fewer nodes: for example, a recent PhD thesis focused on the impact of wind energy on transmission Ummels (2009 page 73), and aggregated countries to a single node each.

Limitation of scope to the high voltage transmission grid

The model used in this research focuses exclusively on the Dutch 380kv transmission grid infrastructure. This is an important limitation to the research: bottlenecks and therefore congestion can and do occur at lower voltage levels, for example within distribution networks. A notable recent example in the Netherlands concerns the capacity of the distribution network in the ‘Westland’ region near to Rotterdam to absorb the electricity generated by decentralized heat and power facilities used in greenhouses.

However, most of the proposals for national congestion management over the medium term foresee application to the 380 kV grid only. Furthermore, the research questions described in chapter one focus on an international perspective to the topic of congestion management. Therefore, the scope of this research is limited to transmission at that level of voltage and to the interconnectors.

A model which deals with national congestion

Much previous research (see e.g. Hobbs and Rijkers (2004b) and Sharma (2007)) in the past focused on congestion which occurs on interconnectors between countries in the north west of Europe, rather than that which may occur within countries. Such models therefore often strongly aggregate or simplify transmission within countries. Because of recent developments, the scope of this research was chosen to include not only congestion between the Netherlands and neighbouring countries, but also the increasingly relevant issue of congestion within the Netherlands (see Chapter 1 for a fuller discussion of this phenomenon).

The relevant question when determining the scope is how to limit the level of detail sufficiently to keep the modelling effort manageable, while not simplifying the scope to such an extent that investigating potential congestion within countries becomes impossible. Issues which relate to both transmission networks within countries and interconnectors between them, such as the potential to avoid congestion within a country by reducing available capacity for trade between countries also require a comparably extensive scope.

With regard to representing the Dutch network, the documents available within the public domain published by the TSO, Tennet (Tennet, 2008b) suggest, on the basis of load-flow calculations, that internal bottlenecks within the Dutch network can be expected to occur in a West-East or a North-South direction (in Annex 3 the results of a load-flow analysis performed by the TSO Tennet is given, suggesting potential congestion consistent with these two directions within the network). Of the four most important production locations[16], the Maasvlakte and Eemshaven will see the most additional capacity over the coming period (Tennet, 2008b). Furthermore, interconnectors used for trade with the electricity markets of neighbouring countries have long experienced congestion.

The model should therefore at least include those links on the Dutch transmission ‘ring’ which may experience congestion and those which are needed for accurate representation of the interconnectors. Specifically, this implies the links to the east of the Maasvlakte, to the north of Zwolle and between Zwolle and the eastern border. The model aggregation is therefore limited to five nodes, including one in the west, one in the south east, one in the east

[16] i.e. Borssele in Zeeland, the Maasvlakte near Rotterdam, Ijmuiden in North Holland and the Eemshaven in the far north.

and two in the North. The graphical representation (see Figure 9b) provides an overview of the geographic scope. Non-green nodes are those beyond the Dutch borders[17].

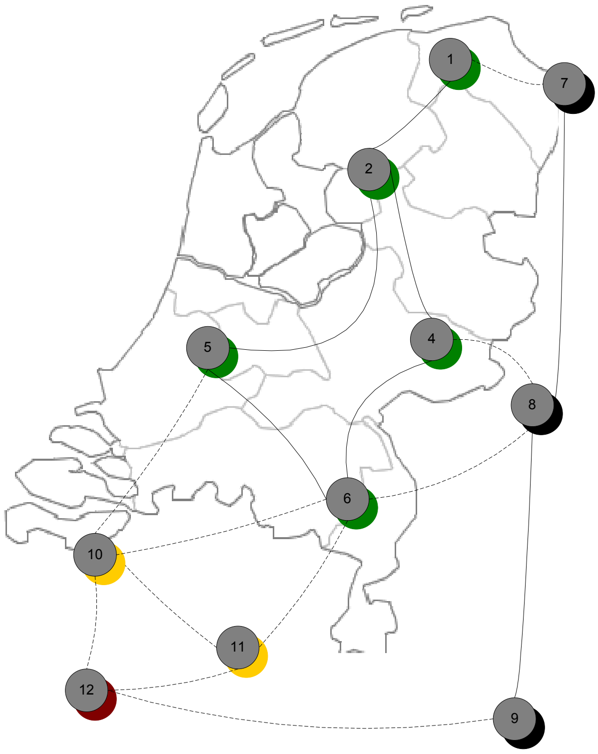

Figure 9b: Choices in model scope:
Dutch transmission grid and neighbouring networks

A model which can also allows for international trade and interconnector congestion

Although the choices outlined in the previous section ensure that congestion can be represented within the Dutch network, this research is also aimed at congestion from an international perspective between the Dutch and neighbouring grids and the interaction between the two. The German market is an important source of electricity imports for the Netherlands, as can be seen from the high average utilization of the interconnectors (NMA, 2008). This occurs in spite of the complications involved in bidding separately in such explicit auctions for transmission capacity and for the corresponding energy sales within national power markets, described in chapter 2. The regional transmission plan for the CWE, German documents relating to transmission investments (German TSOs, 2008) and academic studies such as Leuthold et al. (2008) also suggest that transport between the north and south in the west of Germany forms a similar bottleneck to that anticipated within the Netherlands, especially if rapid wind development continues (Smeers, 2008).

These considerations motivate the choice to model the German grid in greater detail than that of France and Belgium and than has often been done in other studies which aggregate the networks within countries. Germany is represented in this model by three separate nodes,

[17] Note that there is no node with the number three in the model, as this was removed when two nodes were aggregated during an earlier stage of the research.

connected by two transmission links. Each can be interpreted as covering the area of one of the German TSOs: E.ON (Transpower) in the north, RWE (RWE Transportnetz) in the centre and ENBW in the south.

By contrast, France is aggregated in a single node. Belgium is divided into two nodes in order to allow the interconnectors to the Netherlands to be represented separately. However, the parameters for demand and supply in the Belgian market are calculated in aggregate, and divided equally over these two nodes, thereby assuming that the spatial distribution of demand and supply within Belgium are not significant from the perspective of congestion management within the region. This is consistent with the way the Belgian network often serves as a transit point for flows between the larger electricity markets in the region. This assumption simplifies the necessary data gathering with regard to this part of the model, while preserving the accuracy of the representation of the interconnectors on the Dutch and Belgian borders.

A consequence of this choice of model scope is that Franco-German electricity trade and transmission fall outside of the possibilities to investigate more thoroughly than through the aggregated representation shown above. This limits the validity of the results for this aspect of trade between these countries. Although this is consistent with the fact that the primary focus of this research is on congestion management within and between the Netherlands and Germany rather than detailed load-flow modelling on a continental scale, it is important to keep in mind that the real infrastructure of these countries is significantly more complicated than in this model. If and when significant loop flows occur between these two markets, the model scope is likely to be too rough to accurately represent them. This possibility should be kept in mind when interpreting the results of Chapter 4.

Temporal scope

The model is limited in its temporal scope. Specifically, it represents the day-ahead trading for one-hour periods during conditions in which congestion may take place and electricity trade must be adjusted for this to be managed.

In practice, this may not be realistic. The dispatch of real power plants is based on electricity trading over several time frames. In theory, secondary markets allowing trade further ahead of actual transmission should lead to optimal dispatch. However in practice adjustments more close in time to the actual transmission are also necessary which are performed through intra-day trade and balancing markets. However, congestion management through price-based allocation of capacity, in the form of explicit or implicit auctions, is currently limited to day-ahead trading. Furthermore, this is the timeframe in which most of the relevant trade takes place. These are important reasons that motivate limiting the focus of this research to that timeframe. Nevertheless, this choice implies certain limitations.

One concern relates to the realism of assuming that all generation capacity can be employed or not for supply within any given hour. This may not be the case for plants which cannot quickly be started or shut down (such as older coal fired plants[18]), or for capacity which likewise has a must run character due to other reasons, such those plants used to supply heat. In this model, the bidding price of CHP plants is adjusted to ensure that they are dispatched, but extensive representation of ramping up or down is not possible.

Another consequence is that the long-term equilibrium of such systems can only be determined if investment behaviour and market outcomes are modelled during a greater number of consecutive periods, such as months or years. This would allow the frequency of congestion as well as the severity of its consequences to be taken into account in a dynamic model. Because of the limited time available for this research, this has not been done with this model, however modelling a number of different scenarios allows for assessment of multiple situations which may occur. This could be combined with a more qualitative judgment of the expected frequency with the conditions leading to that scenario take place, to allow for an interpretation of the possible consequences for the longer term market behaviour.

General form of the model equations

The model is coded within the GAMS program (version 23.02). This software package allows for the automated optimization of linear and non-linear problems. In this case, the optimization involves maximizing the social surplus resulting from electricity trade, which is represented by the area under the demand curve less the area under the supply curve for electricity (see also section 3.2). Calculation of this variable involves the integration of the functions of these curves between 0 and the resulting electricity price, over all the nodes within the model. The general form of the optimization can be written mathematically as follows:

Maximize $\sum S(i) = \int a - b*(q_d) - \int c * (q_s)$ for all i, where i represents the nodes in the model

Here S(i) is the surplus per node, while the variables q_d and q_s represent the amount of power supplied or consumed at the node. The parameters a, b and c determine the slope of the inverse demand curve and the supply curves, which are linear. The first part of the right hand side of the equality relates to the area under the demand curve, the second to that under the supply curve. These are in fact the demand and supply curves assumed within the model, relating prices and costs to the quantities of electricity.

This way of representing potential for trade of electricity through the equivalence of a spot market was first introduced by Schweppe et al. (1988), and forms the basis of many studies in the literature which quantify the effects of congestion management (e.g. Chao and Peck (1998), Ding and Fuller (1999) and more recently Bjørndal and Jornsten (2008) and Green (2007)). The mathematical optimization problem is referred to as a Consumer and Producer Surplus Maximization problem by authors such as Smeers (2008, page 44)[19].

[18] These plants with long rates for ramping ‘up’ or ‘down’ generation
[19] Although Wood and Wollenberg (1993) note that in the past similar calculations were often formulated as a cost-minimization problem by vertically integrated electricity supply companies.

The quantities of supply and demand are separate variables, but they are related to one another and to the amount of electricity transported to or from the node in question by equations which take the following form:

$$\mathbf{q_s(i) - q_d(i) = q_i(i)} \qquad \mathbf{(1)}$$

For each individual node i, where the variable $\boldsymbol{q_i(i)}$ *represents the quantity of power injected into the grid when it is positive and withdrawn when negative.*

This equation thus ensures that supply and demand at a node must balance, except when a quantity of power is imported from elsewhere to the node (when q_i is negative) or when power is exported from the node to elsewhere (when q_i is positive). So if a node were purely a transit node, q_i would equal 0.

The model must also respect a number of constraints related to the transmission of electricity, in order to allow for the representation of Kirchhoff's laws. These take the general form given below:

$$\mathbf{q_i(i) = \sum q_{ij}} \qquad \mathbf{(2)}$$

Where the variable $\boldsymbol{q_{ij}}$ *represents the quantity of power transported to or from the node i, over link ij, for all links ij connected to node i.*

$$\mathbf{\sum (X_{ij} * q_{ij}) = 0} \qquad \mathbf{(3)}$$

for each independent cycle L within the network, where Xij and Q_{ij} *represent the reactance of and quantity transported through each of the links ij within that cycle*

The first of these two equations ensures that the quantity of power imported to or exported from a node is equal to the balance of the flows transported across the transmission links connected to it. The second constrains the flow of electricity between any two points in the network, to be proportionate to the inverse of the impedance of the network components in accordance with Kirchhoff's laws. The specific application of these equations for the set of nodes in this model is explained in Annex 1, while the algebraic derivation from the generalized equations related to 'DC' load-flow models (given in section 3.2) is demonstrated in Annex 7.

Overall, balance of the energy in the system is equal to zero, represented by the equation:

$$\boldsymbol{\sum q_i = 0} \qquad \mathbf{(4)}$$

For the set of all nodes i.

Finally, the model has additional constraints related to the limited available transmission capacity and to differences between prices for nodes. These are binding or not, depending on the congestion management method of interest and take the following form:

$Q_{ij} <= Q_{max\ ij}$ **(5)**

Where the parameter $Q_{max\ ij}$ represents the maximum[20] *capacity of the transmission link ij.*

$P_d(i) = P(k)$ **(6)**

Where P(k) is the variable indicating the price for electricity calculated by the model for a price zone 'k', and $p_d(i)$ represents the set of variables related to the price at the nodes within that price zone 'k' (e.g. all nodes within the Netherlands).

Model implementation using software

The model described is coded within the GAMS program (version 23.02). The reference version of the model (base case scenario) contains 393 lines of code. While GAMS was used for this research project, other software packages that have been used for similar network modelling include such packages as AIMS and Matlab, and in the case of linear programming MS- Excel. The advantages of choosing GAMS for the research included the fact that it is used in a number of comparable studies (e.g. Leuthold, 2008) and that it can use a number of different solvers, so is flexible for different formulations of the problem.

3.3 Assumptions related to electricity markets

This section explains the most important assumptions made in modelling the electricity market.

Perfect competition

The model represents the aggregated supply and demand side of the electricity market through mathematical functions in the form of supply and demand curves. This means that the relevant actors, i.e. suppliers and consumers of electricity, are not assumed to react dynamically to conditions or to bid strategically based on expected conditions and their ability to influence prices, but rather to simply enter their own bid based on their costs and accept the resulting market outcome (i.e. all supplying firms are assumed to be 'price takers'). More specifically, because the assumed slope of the supply curve is based on estimations related to the variable costs experienced by the suppliers of electricity, the market for electricity supply is in fact modelled as if it were perfectly competitive.

How realistic is this assumption? In practice, the supply side of the Dutch market for electricity is often highly concentrated. The Dutch regulator suggested in its report on the market in 2007 (NMA, 2008) that a clear statistical connection exists between the simultaneous occurrence of dominant positions for market parties and higher prices, although no evidence was found showing abuse of market power.

[20] In the actual model, two equations are used as the flow variable when assuming a negative value indicates transport in a different direction. The corresponding equation is then the same, but with a negative sign.

Studies for the European commission suggest a relatively concentrated Dutch market between 2003 and 2005, estimating a mark-up compared to perfect competition of around 6% (London Economics, 2007) with the largest generator being pivotal for meeting electricity demand no less than 30% of the time. Parties are unlikely to be slower to realize the fact that the TSO has no alternative bids to choose from for counter trading within a specific area in which congestion occurs regularly, than they are now able to identify moments in which their bids set the marginal price for the larger national market as a whole[21]. From a game theory perspective, bidding into day-ahead markets takes on the character of a repeated game (EA Energy analyses) for suppliers, reducing the uncertainty concerning the effects of their actions. These factors imply that the assumption of perfect competition may be a departure from reality, both in the case of zonal pricing and when counter trading is the method being modelled.

In this case, that assumption is less problematic from the perspective of the research objective, if one keeps in mind that the quantitative results should be interpreted as a benchmark of what the full potential of the electricity market under differing methods for congestion management *could be*, rather than as an exact prediction of what the actual outcome *will be* if such policy measures take place. This may be the case for counter trading, if and when there are only limited alternatives for constraining capacity downward. Green (2007) performed extensive research for the U.K., estimating the additional effect of market power on congestion management, finding that this could make the welfare cost of sub-optimal pricing of transmission higher (2,3% - 3,1% of the social costs of congestion) than would otherwise have been the case (1,2%).

Representation of supply bids through linear curves

As mentioned elsewhere in this section, the actions of suppliers of electricity are represented in an aggregated fashion in the model, through mathematical functions. In practice, this smoothes the actual cost function of the individual power plants and simplifies the bidding behaviour of suppliers with respect to reality.

As the true marginal cost data of real power plants are confidential, these costs were estimated per generation technology as is described in the next section (3.3). In order to simplify the necessary calculations, the difference between running the same power plant at minimal or maximal operating efficiency may be ignored, giving an initial stepwise function when bids are combined (see Figure 10). In practice, generators can vary the quantity they produce within a certain operating range and will generally be somewhat less efficient at the lower end of this, therefore the result of constructing a combined supply function of their production capabilities based on a merit order of true marginal cost might look somewhat more like a piecewise linear curve (see the left of Figure 10).

The level of the steps of such a supply curve should as best as possible reflect the marginal costs of the technology used for generation. (Leuthold et al., 2008) used marginal cost data for

[21] As noted in chapter two, measuring such hours for a specific firm within a market forms the basis of an indicator known as the Pivotal Supplier Index (PSI). This is often used as an indicator of market concentration for electricity markets.

the fuel type used to estimate stepwise supply curves representing the generation at the nodes in the German network. In Bjørndal and Jornsten (2007) the authors use an upwards sloping curve with two parameters for each node, the first implying a gentle slope and the second a steeper one representing the higher marginal cost of (peak) power at high levels of demand, which gives a curve resembling the first graph, but with two distinct slopes. These parameters are varied "based on the type of generation used most at a particular node". Sharma (2007) estimated a national linear curve based on the values of the quantities per generating technology and their marginal cost price. This gives a curve more like the one displayed below (see Figure 11).

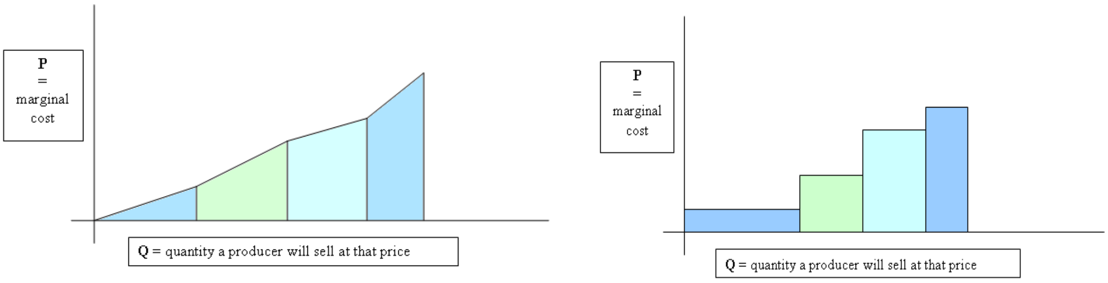

Figure 10: piecewise linear / stepwise supply curve examples

For this model, an approach using linear curves is adopted, but there are different supply curves for each of the nodes in the Dutch and German networks. The program used to build this model proved to be a limiting factor, as using conditional functions such as those necessary for piecewise linear curves made solving the optimization difficult [22]. In addition, linear curves are the most straightforward to estimate per node and to translate into functions within the optimization model. Given the necessity of modelling multiple nodes, this is an important advantage. Nevertheless, it is important to remember that real markets for electricity working with bids resembling step functions, may feature less smooth behaviour than that of the model.

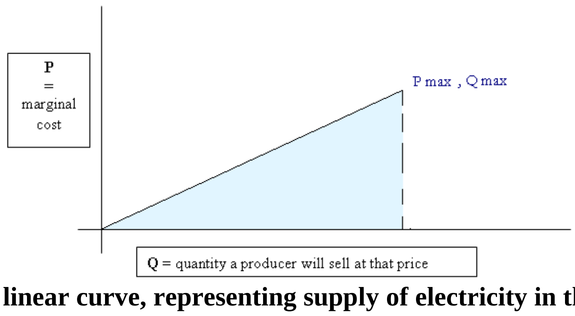

Figure 11: example of a linear curve, representing supply of electricity in the market at given node

3.4 Modelling the transmission network and electricity flows

[22] Possible approaches to using such functions in a similar GAMS model could be to approximate the desired curves using separable functions (replacing each function with multiple equations and variables) or integer programming as described by sources such as Williams (1995). The first approach would increase the size of the model greatly, the second could make the problem more difficult to solve.

This section describes the most important assumptions related to the way in which the transmission network and the flows through it are represented within the model.

Lossless 'DC' linear approximation of physical transport

TSOs model flows over the AC network using complicated load-flow models. In order to capture the physics of electricity transport, these are based on laws such as Ohm's law (describing the relationship between the resistance, the current and the power occurring across an electrical component) and Kirchhoff's laws (which govern the way power flows through the network). In order to give a complete representation of what takes place in reality, these models should cover both real and reactive power flows to give AC load-flows.

In practice, a linear approximation is often applied in models used for research into congestion management as this greatly simplifies the necessary calculations for all but the smallest of networks. This sort of model has been labelled a lossless linear 'DC' (load-flow) approximation, though this name is somewhat misleading. In practice, the fact that this name used in the academic literature for the family of network models does not follow from the fact that the network is represented in direct current form, but rather because the linear relationship between active power and phase angles in such a model is comparable to the relationship between current and voltage in a DC network with resistors (Bjørndal and Jornsten, 2007).

The set of simplifying assumptions underlying such a representation involve first assuming that all voltages have a constant unit value, secondly that the differences in phase angles across transmission lines are very small and that the resistance of lines can be considered compared to the reactance (which is why the resulting approximation is lossless). An explanation is given in various sources such as Wood and Wollenberg (1984, page 109). The most important equations following from these simplifications are formulated by Wood and Wollenberg (1984) as follows:

$$\mathbf{P_F(ij) = 1 / X_{ij} * (\theta\ (i) - \theta\ (j))} \qquad \textbf{(7)}$$

Where $P_F(ij)$ or 'power flow' is used in the place of $Q_{ij}(i)$ 'quantity transported between nodes i and j 'in the equations noted in the previous section, and θ (i) refers to the voltage phase angle at a given node 'i'.

$$\mathbf{\sum P(i) = \sum P(ij)} \qquad \textbf{(8)}$$

Where P(i) , 'the sum of power at node 'i' ', *is used in place of $Q_i(i)$, the 'quantity injected or withdrawn at a node' and P(ij) refers to the quantity transported to i over link ij, for all such links connected to node i.*

The second equation is directly implemented in the equations of the model, as described in section 3.1 of this chapter. The first can be related to the equations given for each individual independent network cycle in section 3.1 through the algebraic steps described in Annex 7.

The consequence of these simplifications is that the real[23] power flow in MW can be calculated, but that reactive power is not included in the scope of the model. Although reactive power may be important in operational management of the grid, its influence on the economic outcomes of the system is limited (Chao and Peck, 1996) so it is assumed that disregarding it for the purposes of this research does not strongly affect the outcomes of interest. The second consequence of the assumptions noted above is that the model will disregard the resistance of the lines (and other components, such as transformers), and the accompanying losses during transport of electricity.

Are transmission losses economically insignificant? Although as is mentioned in (1.3) losses are form one of the three cost components for transmission, they are recouped over the all transport of electricity rather than just over periods of congestion. Losses will in practice increase with greater transport distance, and could constitute a significant percentage of costs in systems which are poorly maintained or that cover large physical areas, such as those in the United States. Disregarding them for a grid that is relatively limited in geographic scope, such as that of the Netherlands, will imply a limited margin of error in the quantities calculated[24].

In order to ensure that these two effects do not lead to overestimation of the infrastructure's true transmission capacity, a safety margin is estimated with regard to the rated thermal capacity of the transmission lines. The estimation of this margin is explained in Annex 6. This margin also includes the normal operational provision to deal with contingencies (as the network is designed and operated so that failure of one[25] (or more components) will not lead to a systemic failure in service).

DC Interconnectors

One of the interconnectors which links the Dutch transmission network to the Norwegian grid is a DC link. It is assumed that this is used fully to import power during periods of high demand. The link is represented as 700 MW of hydropower capacity at the node where it enters the Dutch grid. A second such interconnector, BritNed, is planned. This will link the Dutch and UK grids. It is assumed that this link is also fully used for imports during high demand periods, and it is modelled as 1000 MW of natural gas combined cycle generation in the west of the Netherlands.

3.5 Sources of data used to estimate model parameters

This section describes in brief the sources of data and the steps involved in the estimation of parameters which serve as input for the model. Both the sources of uncertainty with regard to the data and a sensitivity analysis in which many of these values are varied in order to assess their influence on the model results are described in the next section of this chapter.

[23] That is, that part of the power that can usefully be applied to do work. In an AC electrical system, voltages and currents fluctuate. Reactive power refers to that component of power which is 'stored' and returned to the system as this happens.
[24] Losses in the Dutch network are in the order of a few percentage points.
[25] In the case of one contingency this is referred to as 'n-1'

Power plants and supply curves

Data on the location and size of existing power plants and planned capacity to be built in the Netherlands was gathered from Tennet's capacity and quality study for 2014 (2008b) and overviews of existing capacity (2009). As in the former of these two sources, it is assumed for the purposes of this study that power plants which are planned and have been granted a connection permit will be realized. Data for power plant capacities in Belgium and France is based on Elia (2009) and on nationally aggregated figures from the UCTE's supply adequacy forecast (2008). German data are based on information from publications of expected developments fuel mix and cumulative capacity per region given by the German TSO's (2009). These data and the calculation of the supply curves are explained in greater detail in Annex 4.

As is noted in section 3.2, it is assumed in the model that suppliers will bid based on their variable costs (as perfect competition is assumed). These variable costs are represented for the purposes of the model using three components: fuel costs, CO_2 emissions permitting costs and operation and maintenance. (Renewable and nuclear power plants pay no CO_2 emissions costs). These costs represent sensitive information, and are thus considered to be confidential. They were therefore estimated based on generic data for efficiencies from sources in the academic literature, including Ummels (2009) and De Jong (2009). Fuel price data for gas, coal and oil and CO_2 prices are perhaps the most variable of these factors. Estimates for these costs were based on the 2008 World Energy Outlook (IEA, 2008), but are also varied as part of the scenarios and the sensitivity analysis.

Demand growth and division over regions

National demand and annual growth estimates for the next five years are based on the UCTE supply adequacy forecast (2008). The division of demand between the regions was found using the assumption that demand for electricity is strongly correlated with economic output. This has been used previously as a method for comparable studies of the German electricity network by (Leuthold et al., 2008). In this case, data for the Netherlands were supplied on request by Tennet (2009) on a municipal basis. These were manipulated to aggregate the data to the provincial level. The division of the demand between the provinces and nodes is further discussed in Annex 5.

The division of German demand was estimated from the predictions for the year 2014 by the German TSOs, as is described in Annex 5.

Network characteristics and technical data

Technical data for the Dutch transmission network was estimated based on public data from Tennet (Tennet, 2008d). The aggregated reactance of transmission lines in series was found by adding this for the lines in question. Where capacities differed, the lower value was assumed to act as a constraint on the maximum flow. The aggregated value for German capacity was based on an earlier academic study by Hobbs and de Rijkers, (2004b)as no suitable public data could be acquired within the time available for the research from the German TSO's[26]. The capacity of interconnectors between countries was conservatively estimated by adopting the net transfer capacity (NTC) for the winter of the year 2009 (Entso-E, 2009). Although the rated thermal capacity of such links is much higher than this value, in practice the TSOs use such conservative estimates to deal with the uncertain flows from neighbouring countries. These data, along with the safety margins mentioned in the previous section are explained in greater detail in Annex 6.

3.6 Systematic overview of threats to validity of the model, sensitivity analysis and the use of scenarios to deal with uncertainty

Research using a model such as that described in this thesis is vulnerable to errors related to both the information used to build it and the data which serve as its input. In order to increase the confidence in this model's external validity, this section of the chapter discusses the relevant challenges involved in finding the information necessary for building and applying the model and the outcomes of an analysis aimed at investigating its sensitivity to changes in the input parameters and structure. Finally, the use of different scenarios to cover the range of possible future developments within the results is explained.

Data quality issues and availability

Gathering the required data for this research posed several challenges, related to the quality and availability of the information. First, some of the information concerned such as precise technical characteristics of plants and cost data is considered to be confidential, and is therefore unlikely to be shared by the relevant actors.

Because of the scope of the research, some of the information related to infrastructure and markets in other countries, which generally proved more difficult to obtain than information related to the Netherlands. The legally required disclosure of such information to interested third parties may be similar on paper in Germany, but because the TSOs remain part of companies such as RWE and E.On, rather than being fully unbundled and owned by the government as in the Netherlands, they are not inclined to share data for research purposes.

A third challenge related to gathering information is that some future developments are simply unknown. For example, it can be difficult to predict in advance how operational practice will change when market coupling is introduced with the meshed German network, although this could be relevant to the amount of transmission capacity made available to the market on the interconnectors.

In the light of the challenges described in gathering the necessary data for performing the research, a careful approach is necessary when interpreting the validity of the resulting model and its results. Where the desired data could be found, uncertainty related to estimation of future developments remains present.

[26] In fact, a request for such data to each TSO met with no positive responses.

The research described in this thesis takes these issues into account in two ways: the sensitivity of the model to changes in the input parameters is assessed in an analysis, and different scenarios are used to take into account a range of plausible future developments. Both the outcomes of this sensitivity analysis and the approach applied in designing and using the scenarios are discussed in this section of the chapter.

Sensitivity analysis

Building and using a model of the sort described in this thesis, involves making a number of assumptions and estimates. In order to be able to put these into perspective, the sensitivity of the model can be assessed by varying the values of the most important such input parameters. This analysis describes and discusses the changes to the output of the model that together form a sensitivity analysis of the model created and used in the research that is the subject of this thesis.

Specifically, the effects of changes to the input parameters related to price and quantity of electricity supply available are first discussed. Changes to available quantities of generation capacity are considered, as well as the percentage of available wind power capacity is varied. Turning to the demand for electricity, the model is rerun with differing demand curve parameters. Next, transmission is investigated. As the capacity available on the interconnectors is varied as part of the research results described in chapter 4, only the capacity margin for transmission links in the Dutch network is considered here. The effects of removing the differentiation of the impedance of each transmission line on the model behaviour is also shown, by recalculating the flows given equal values. Finally, the parameters related to the German network are varied separately to the rest of the model, in order to allow the influence of these estimations to be shown. In each case, the main model output shown is the social surplus - the indicator that represents the difference between the willingness of consumers to pay for electricity and the costs of producing it, which is the variable that the model optimizes when run. The most notable results are briefly discussed for each set of results.

Parameters related to the price and quantity of electricity supply

As described in Annex 4, of the factors used to estimate variable cost, important components such as fuel costs may be relatively volatile over the time period between the time of writing and that considered in this research. Variations in supply costs are therefore investigated as part of this analysis. A closer look at the specific fuel mix assumed within Germany and the Netherlands is described in Annex 10. The French supply curve is investigated in greater detail in Annex 9.

Table 3 lists the effect of the changes to the social surplus under unconstrained dispatch (UD), optimal dispatch (OD) and counter trade (CT) (i.e. when national price zones are applied) when costs increase or decrease. The next table shows the effects of increased or decreased generation capacity, while the third shows the effects of varying wind capacity.

Table 3: Changes to surplus resulting from altered cost parameters

Parameter changed	**base case**			**scenario b**			**scenario c**			**scenario d**		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Reference value (million Euros / hr)	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
cost of electricity supply + 10%	16,917	16,912	16,912	17,121	17,049	17,045	16,196	16,193	16,193	16,656	16,511	16,509
cost of electricity supply - 10%	17,618	17,612	17,611	17,799	17,730	17,728	16,968	16,965	16,965	17,310	17,279	17,278

In general, these results show that an increase in the unit cost parameter at the nodes will lead to overall price increases that are more or less proportional to that rise, but that the change in surplus will still vary depending on transmission constraints and congestion management. An interesting result is that the minimal congestion costs increase in scenario 'd' are quite high when the cost decreases. This can be explained by the fact that this scenario already involves a drop in (cheaper) French supply while demand is fixed, leading to a large demand for import of power in the unconstrained case.
A decrease in price in general leads to higher consumption and to higher demand for transport of electricity.

Table 4: Changes to surplus resulting from altered generation capacity

Parameter changed	**base case**			**scenario b**			**scenario c**			**scenario d**		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Reference value (million Euros /hour)	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
Maximum generation capacity + 25%	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
Maximum generation	17,259	17,249	17,248	17,453	17,375	17,371	16,572	16,569	16,569	16,930	16,841	16,634

capacity - 25%												

Increasing the maximum available generation capacity (see table 4) without changes to the cost structure does not change the results, showing that these constraints are not limiting the model results described in chapters three and four. Reducing it by the same margin does for a number of the scenarios. This is because the maximum capacity is reached in France, except in the case of scenario C where demand is somewhat lower due to the higher prices that are part of the scenario (due to a higher CO_2 permit price).

Lastly, the effects of differing wind power availability are shown (table 5). The influence on results is relatively large, which is not a surprise, as the difference between the assumed availability in the base case (25% of rated capacity) and that in the scenarios B and C (100% of rated capacity) is variation of a factor four. This range is also applied in the analysis shown above, and is larger in magnitude than the difference in capacity constructed between the various scenarios (which is around twice as much in scenarios B and C compared to the base case).

Table 5: Changes to surplus resulting from altered cost parameters

Parameter changed	**base case**			**scenario b**			**scenario c**			**scenario d**		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Wind power availability 25% (million Euros /hour)	17,260	17,254	17,254	17,270	17,263	17,263	16,488	16,487	16,487	16,931	16,891	1,6890
Wind power availability 50%	17,302	17,283	17,281	17,328	17,306	17,305	16,553	16,543	16,542	16,980	16,919	16,917
Wind power availability 75%	17,349	17,311	17,309	17,389	17,435	17,342	16,623	16,595	16,593	17,034	16,947	16,944
Wind power availability 100%	17,397	17,336	17,333	17,453	17,382	17,379	16,673	16,612	16,608	17,091	16,792	16,967

Parameters related to the demand for electricity

Demand for electricity is defined by two parameters: the slope of the curve and its intercept with the y-axis. In order to assess the sensitivity of the model to stronger or weaker demand, the slope is varied[27].

[27] Note that changing the slope of the function also results in a shift in the other parameter, as this represents the intercept of the curve with the horizontal axis.

Table 6: Changes to surplus resulting from demand curve parameters

Parameter changed	base case			scenario b			scenario c			scenario d		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Reference value (million Euros /hour)	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
Slope of inverse demand curve + 10%	15,986	15,982	15,982	16,152	16,094	16,092	15,392	15,390	15,390	15,638	15,577	15,575
Slope of inverse demand curve - 10%	18,756	18,748	18,747	18,983	18,895	18,891	17,951	17,945	17,945	18,348	18,325	18,323

These results (see table 6) show that the social surplus for the electricity trade as a whole is affected by the assumption of what level of demand exists. However, changing the slope of the curve does not translate into strongly different results when comparing different forms of congestion management.

Parameters related to the transmission of electricity

The maximum capacity of interconnectors between Germany and the Netherlands has been increased by 50% in the model results as described in chapter three. The thermal capacity data of Dutch internal transmission links is based on the data given by Tennet. However, another important parameter relates to the operational margin of that capacity that can safely be used due to reservations related to contingencies (to prevent systemic failure following from the of failure of any one component), losses and reactive power considerations. This was estimated in the model as 2/3 of capacity. In order to provide a broad overview of the sensitivity of the model to this parameter, it is varied to 1/3 and all of the capacity.

Table 7: Changes to surplus resulting from altered transmission capacity parameters

Parameter changed	base case			scenario b			scenario c			scenario d		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Reference value (million Euros /hour)	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890

(2/3 of TC)												
1/3 of TC	17,260	17,234	17,231	17,453	17,353	17,346	16,572	16,557	16,554	16,931	16,868	16,863
3/3 of TC	17,260	17,254	17,254	17,453	17,387	17,384	16,572	16,569	16,569	16,931	16,891	16,890

These results (see table 7) show that congestion would increase with lower transmission capacity within the Netherlands and decrease with higher capacity. For the base case and scenario's C and D, increased capacity within the Netherlands makes less difference to the scope of the results.

The flows in the model are also constrained by the relative reactance of the different transmission links. This is consistent with the physics of Kirchhoff's laws, that dictate that flows of electricity divide in inverse proportion to the impedance of paths in an electrical network. However, the data on the reactance of lines is aggregated due to the scope of the model, and excludes certain components such as transformers which are present in reality. In order to judge the sensitivity of the model results to the reactance values assumed, the model is rerun using equal reactance values for each link. The resulting flows are compared for the base case scenario in the table below (unconstrained by transmission capacity limits).

Table 8: Changes to flows resulting from equal reactance for all lines

Transmission link	**Flow using reactance data**	**Flow assuming equal reactance**
1-2	4506	3094
1-7	-1479	-68
2-4	1851	1009
2-5	1717	1148
4-8	-684	-1319
4-6	919	711
5-6	839	571
5-10	1592	1290
6-8	-1851	-2030
6-10	687	719
6-11	1368	1041
7-8	1440	2852
8-9	1921	2518
9-12	330	927
10-12	838	695
10-11	450	322
11-12	827	373

The results (see Table 8) reflect that the interconnectors represented in Germany are longer than those in the Netherlands, so assuming all reactances are equal would tend to overestimate the flows through the internal links of the German grid.

Sensitivity of the model to parameters of the German network

As the data relating to the German network and electricity market was aggregated to a greater level than is the case for the Dutch network, these data have also been varied separately while keeping the other parameters constant.

Table 9: Changes to surplus resulting from altered cost parameters

Parameter changed	base case			scenario b			scenario c			scenario d		
CM method	UD	OD	CT	UD	OD	CT	UD	OD	CT	UD	OD	CT
Reference value (million Euros /hour)	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
German supply curves + 10%	17,161	17,159	17,159	17,354	17,297	17,293	16,471	16,468	16,467	16,814	16,789	16,788
German supply curve - 10%	17,375	17,356	17,356	17,563	17,470	17,466	16,686	16,676	16,675	17,065	16,999	16,997
German transmission + 50%	17,260	17,254	17,254	17,453	17,382	17,379	16,572	16,569	16,569	16,931	16,891	16,890
German transmission - 50%	17,260	17,252	17,251	17,453	17,372	17,368	16,572	16,567	16,567	16,931	16,886	16,883

As with the Dutch transmission lines, increasing the capacity reduces the costs of congestion while decreasing ensures their limits are more quickly reached and increases both the minimal congestion costs and to a lesser extent the extra loss in economic efficiency resulting from counter trading.

Sensitivity of the model to changes in scope and methodology

The results discussed in this sensitivity analysis indicate that while the magnitude of the outcomes can vary somewhat depending on the input parameters, the occurrence of congestion and the scope of the differences between methods remains similar throughout.

Changing the number of nodes in the model would also have an influence on the results. In particular, it should be noted that modelling the larger nodes, such as those currently representing much of the German or French networks and markets to a greater level of detail could affect the results.

Currently, it is not possible to represent transport between locations within a node. This implies that increasing the number of these nodes could increase the resistance to flows of electricity which pass through the areas covered by them. In some cases, such as nodes with various plants with strongly differing costs of supply, splitting the nodes could lead to a more accurate representation of dispatch (e.g. if off-shore wind power were to be represented in separate locations).

The same effect would be likely to occur if non-linear curves such as step-functions were used to represent supply. However, given the scope of the adjustments to the model necessary to quantify such changes, doing so is considered beyond the scope of the time available for this research.

Use of scenarios to deal with uncertainty

Where the sensitivity analysis can be used to gain insight into the way in which the model results can change given errors in the input, the uncertainty relating to the most relevant future developments in the outlook period is dealt with within the results by using a range of scenarios. These scenarios are chosen in order to demonstrate the effects of plausible causes of congestion. Many such potential causes can be imagined, as is shown in table 10.

Table 10: An overview of potential causes of uncertainty regarding future electricity market developments

Part of model affected	cause of change	possible consequence
generation units	- Old plants retired (e.g. high CO_2 price, inefficient coal) - Extra investment (e.g. higher growth scenario, high prices) - Additional renewable power plants (political climate, policy shifts) - Available wind depends strongly on incidental conditions	Shifts in transport demand, leading to changes in congestion of lines
merit order of generation units	- CO_2 permit price policy - Changes in fuel prices - Technological developments related to efficiency of specific forms of generation	Shifts in transport demand, leading to changes in congestion of lines
available transmission infrastructure	- Failure of parts of the network (e.g. a transmission line burns down) - Approval or delay of plans for new interconnectors and lines (e.g. Brit-Ned) - Changes to calculation of available capacity margins	Lower transport capacity, leading to congestion given the same demand for transport
demand for electricity	- Increased price consciousness (e.g. due to smart metering, environmental policies such as banning conventional light bulbs, aggressive competition in the retail market) - Shifts in industrial demand (e.g. due to economic crisis, reduction in energy intensive manufacturing in NL and BEL)	Greater overall demand for transport, leading to congested lines, or decline, preventing it.

These causes include incidental occurrences and more structural causes of congestion, such as investments in generation and transmission infrastructure with long life times. The scenarios chosen reflect both.

Scenario D is based on the hypothetical short-term failure of nuclear power facilities in France, and scenarios B and C include high wind conditions, which are temporary in nature. These two scenarios also consider more long-term developments. The quantity and location of the wind power which is varied between is based on the Dutch governments plans for achieving 6000 MW of wind power during the coming decade (Ecofys, 2009). Scenario C also features a shift in the price of CO_2 permits, which implies a shift in the merit order between fuel types. This could lead to greater demand for the export of Dutch gas-fired power to meet German demand.

Transmission lines often have long lead times, and are often delayed due to regulatory issues and spatial planning procedures. The existing approved plan for increased transmission capacity between the Netherlands and Germany in the form of a new interconnector is therefore considered for all scenarios separately from the main results in chapter 4. Projects (e.g. the 'Cobra' link with the Danish network) which have not yet been granted permission to construct are considered beyond the scope of this research.

The scenarios that have been modelled represent possible developments related to both the quantity of generation capacity available to the market (e.g. the level of installed off-shore wind power) and the price at which this is offered (e.g. a rise in CO_2 emission permit prices). These developments demonstrate the magnitude of congestion and the consequences of different methods for managing it. In addition, a base case scenario was modelled to create a yardstick for comparisons. The value of the parameters in question can be found in Annexes 8 and 11. Each scenario is briefly described here.

Base case scenario: 'normal' winter peak in 2014

This base case represents peak winter demand, under otherwise normal conditions. It assumes wind power production at ¼ of rated capacity[28], and fuel prices as given in the World Energy Outlook (IEA, 2008) for 2014. Offshore wind power is assumed to be built in the Netherlands conforming to government plans (2500MW, mainly off the west coast). Planned fossil fuelled power plants which have been granted connections to the grid are assumed to be realized.

Scenario B: rapid wind power development and windy conditions in the north

One potential cause for congestion can be found in the large amount of new power generation capacity planned, notably in the north of the Netherlands. If this were to be combined with a high quantity of offshore wind power development, both in this region and in the north of Germany then strong wind conditions this could strain on transmission capacity in a north-south direction.

[28] Statistics by CBS (2009) suggest a capacity factor of around 25% conforms to the capacity factor realized by existing wind turbines in the Netherlands during recent years.

This forms the context for scenario B, which assumes rapid wind power development in the north of the Netherlands, and is based on a recent study carried out for the Dutch Ministry of Economic Affairs[29] (2009). The scenario also assumes that all wind power in the Netherlands and Germany is employed at full rated capacity (i.e. optimal wind conditions prevail for generation).

Scenario C: rapid wind power development in the west and high CO_2 prices

This scenario is aimed at investigating circumstances which could lead to congestion between the west and the east of the Dutch and German grids. Two changes were made to the base case scenario. Firstly, wind power is assumed to be rapidly deployed, as in scenario B, however it is now assumed to be located off the western shore of the Netherlands. The CO_2 price is then assumed to be twice as high as estimated in the base case scenario. Effectively, this shifts the merit order for electricity supply so that natural gas fired power plants become cheaper than more carbon-intensive coal and lignite alternatives.

This is a development consistent with very ambitious targets for emissions reductions emerging from international negotiations over the medium term. These two factors should combine to offer strong incentives to transport power from the west of the CWE area to the east, as Germany has a higher concentration of CO_2 intensive power plants which use lignite and coal as fuel.

Scenario D: Nuclear power plant failures in France

Scenario B could be considered a set of circumstances where an incidental surplus in supply leads to congestion. However, the reverse is also conceivable: a temporary shortfall. This scenario looks at the consequences of a serious power plant failure in France – for example, an acute operational safety concern leading to the shutdown of one or more nuclear reactors of a certain type. This could ‘pull’ transport of electricity to the south of the CWE area.

3.7 Relevant model outputs, results and zonal configurations

As noted in chapter two, both the flows of electricity and their economic consequences are output that can be found using a model that covers both electricity markets and transmission network operation. For each of the scenarios, several model runs have been performed to find variations in social surplus, prices, congestion costs and flows of electricity. Social surplus is found by subtracting the area under the supply curve (the costs of supplying electricity) from the area under the demand curve (what consumers are willing to pay for electricity).

First, the model is run without any limits to electricity transmission, which gives the surplus under Unconstrained Dispatch (UD) and leads to a single price across all the nodes. This can be considered as a quantitative measure of the social benefits of electricity trade for both producers and consumers. Flows through the network are calculated. The flows that would

[29] In the Netherlands, the Ministry of Economic Affairs is responsible for renewable energy policy

exceed the limits of transmission links are displayed graphically using arrows on the transmission links.

Next, the model is run with transmission limits, but without limits on the variation in prices between nodes. The model outcome then conforms to nodal pricing[30], which can be considered to be an Optimal Dispatch (OD). The difference between the unconstrained and the optimal dispatch gives an estimate of what the minimal costs of congestion could be, if scarce capacity were reflected in differing prices for electricity in different places.

The model is then run twice with prices constrained in order to conform to existing national price zones rather than reflecting scarce capacity. This is first done without internal transmission constraints[31] so as to represent a national unconstrained dispatch. Next, the run is repeated with these transmission constraints included, in order to find the adjustments to power generation that would be necessary to manage congestion using counter trading rather than pricing (CT). This can be considered an optimistic or conservative estimate of what the real costs of counter trading would be, as the model calculates this by adjusting capacity at all nodes rather than being limited by national options as would be likely in practice.

The results for the different congestion management methods, the prices for electricity and the flows that surpass capacity limits in the unconstrained dispatch are discussed in section 4.2.

Where significant congestion was found on links within national networks, the model was also run using more precise possible price zone configurations within countries. This represents a somewhat more aggregated form of congestion management compared to the full nodal pricing approach. These results are discussed separately in section 4.3.

3.8 Conclusions

Any model involves simplifications. This model aims to support policymakers in assessing the differences in the order of magnitude between different congestion management methods. It builds on central assumptions which are well known in the existing academic literature on congestion management: that of spot market pricing introduced by Schweppe et al (1988) which is coupled with the assumption of perfect competition, and the ‘DC’ load-flow approximation, which is covered in various books such as Wood and Wollenberg (1984). These are combined with data on the supply and demand for electricity within the Dutch, German, Belgian and French markets as well as estimates of their growth and the developments in fuel prices and CO_2 prices to give a model consisting of a set of equations which can be solved using optimization software, in this case GAMS.

Taken together, these simplifications make the research possible by allowing for a manageable representation of the electricity markets and networks without surrendering too much accuracy. However, it is important to keep in mind when interpreting the results that they will imply a margin of error. As the future is uncertain, data estimates add to this margin of error. The results should therefore be interpreted as the best possible attempt to represent

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[30] Although with strongly aggregated nodes.
[31] That is, with no constraints to transmission within each national grid.

the developments of the coming years with a significant margin of uncertainty, rather than as a cast iron prediction of what will actually happen. Where possible, this research attempts to give a conservative estimate of congestion costs. The results can therefore serve usefully as a cautious benchmark of the effects of congestion.

A sensitivity analysis has been performed that can be of help in assessing the robustness of the results to future developments. This analysis suggests that although the magnitude of the results may be affected, the behaviour shown by the model is relatively robust to changes in its input. Uncertainty implicit in predicting developments in generation capacity, transmission capacity and incidental conditions may affect the occurrence of congestion. In order to gain insight into the range of outcomes and the order of magnitude of the differences between possible developments, four scenarios were developed to generate a set of results covering multiple potential future situations.

4 Model results and interpretation

In Chapter three of this thesis, the quantitative model used to investigate the research questions formulated in Chapter one is introduced. That chapter also lists the most important methodological choices, assumptions and the sources of data that were used for the estimation of the model input. Section 3.6 describes a base case and series of scenarios (B, C and D) in which congestion may be expected to occur within the Netherlands. The table below reproduces the differences between these scenarios. As noted in section 3.7, the model results which are of interest include the differences in social surplus resulting from the application of different congestion management methods, the prices of electricity and the flows that exceed capacity limits.

Table 11: Overview of scenarios

Scenario => **Input**	**Base case**	**Scenario B**	**Scenario C**	**Scenario D**
Change in supply capacity	2500 MW of wind in Ijmuiden	4400 MW wind in Ijmuiden, 1000 MW wind in Eemshaven	5000MW wind in Ijmuiden, 400 MW wind in Eemshaven	(1400) MW nuclear power in France
Wind availability	25% of rated capacity	100% of rated capacity	100% of rated capacity	25% of rated capacity
CO_2 permit price	20 euro/tonne	20 euro/tonne	40 euro/tonne	20 euro/tonne

This chapter presents the results of the model. Section 4.1 lists the results for each of the scenarios as well as brief descriptions of the model behaviour that can be identified. The next section (4.2) relates these results to the research questions, allowing the output to be interpreted. A closer look is taken at some potential configurations for price zones within countries in section 4.3, while the final section (4.4) describes the effects of increasing interconnector capacity.

4.1 Overview of the results per scenario

This section gives a concise overview of the results of the model output. The interpretation of these results forms the subject of the next section (4.2). For each scenario, flows which would exceed capacity limits given unconstrained dispatch are displayed graphically as blue arrows. The economic effects are given for the various possible congestion management methods in the form of a table listing the value of the social surplus. This is an indicator for the benefit to both consumers and suppliers resulting from trade in electricity (Lesieutre et al., 2004), and reductions in this can be seen as representing the social costs of congestion, as is explained in section 3.7. Finally, relevant data concerning prices are listed per country and the estimated costs of managing congestion using either an optimal dispatch (i.e. nodal prices) and using counter trade are given for each scenario.

Base case

This scenario gives a base case prediction for winter peak conditions, without exceptional conditions which could strengthen the expectation of congestion. Flows exceeding transmission limits when transmission limits do not constrain trade are displayed using arrows in the figure below (see Figure 12).

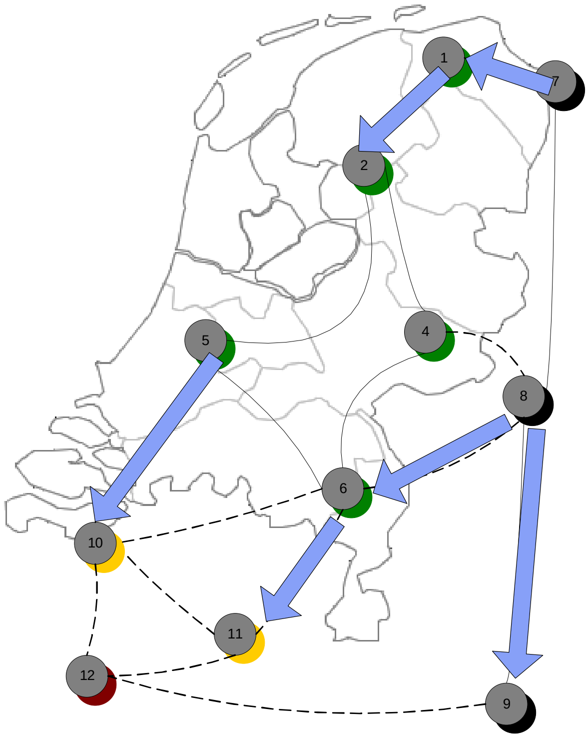

Figure 12: Flows exceeding transmission capacity given unconstrained dispatch for base case

The table indicates the changes to the social surplus value for the congestion management methods. This is an indicator of the difference between the willingness of consumers to pay for electricity and the costs of supplying it, as is explained in section 3.7. Under unconstrained dispatch, this figure can therefore be read as the potential to supply the market demand at minimal cost. The amount by which the outcome from managing congestion lead to a decrease in this indicator may be seen as the resulting social cost.

Table 12: Surplus and additional costs of congestion for base case scenario

Surplus unconstrained dispatch (€ million / hour)	**optimal dispatch** (€/ hour)	**counter trade** (€/ hour)
17,260	5554	5872

As can be seen in tables 11, 12 and 13, nodal prices differ from those which occur when national price zones are enforced. Nodes which export surplus capacity would have lower prices under the former method for managing congestion. This scenario is considered a reference for what is most likely to be the case, given peak demand and known developments between now and 2014.

Table 13: Nodal and national prices for base case scenario – Dutch nodes

Node	**1**	**2**	**4**	**5**	**6**
price optimal dispatch	41,2	42	42,1	40,8	42,6
price counter trade	41,3	41,3	41,3	41,3	41,3

Table 14: Nodal and national prices for base case scenario – Belgian and French nodes

Node	10	11	12
price optimal dispatch	44,7	43,6	43,5
price counter trade	44,2	44,2	43,5

Table 15: Nodal and national prices for base case scenario – German nodes

Node	7	8	9
price optimal dispatch	36,7	41,8	42,8
price counter trade	41,6	41,6	41,6

Scenario B: Wind in the north

This scenario combines rapid wind development in the north of the Netherlands (1000 MW offshore in node 1) with windy conditions both there and in Germany. The market therefore provides greater incentives to transport wind power produced in the north of the region through the network to the south, effectively displacing (thermal) generation elsewhere.

Flows exceeding transmission limits are displayed using arrows in the figure below (see Figure 13). As can be seen in the diagram displaying unconstrained dispatch, many transmission links would be effectively overburdened if the market were not constrained at all. This is likewise reflected in a far greater difference between the unconstrained dispatch and the optimal dispatch figures (71.000 Euros per hour): this is around ten times that of the base case scenario.

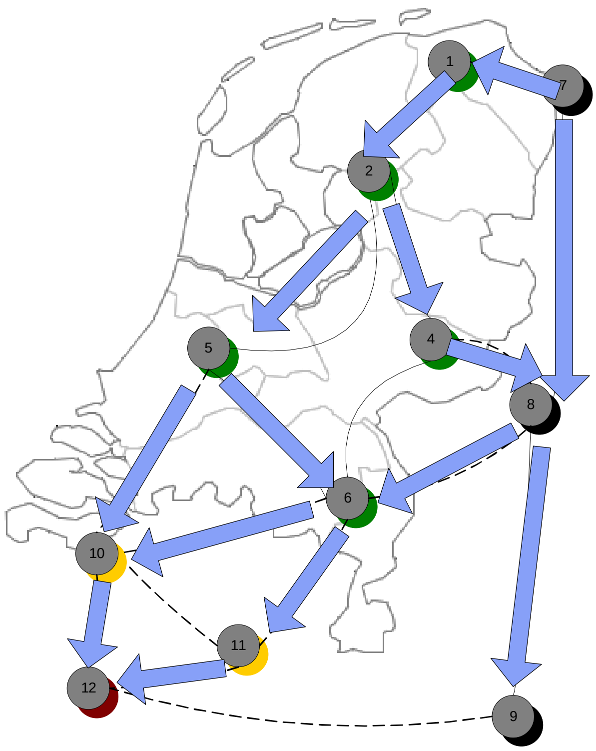

Figure 13: Flows exceeding transmission capacity given unconstrained dispatch for scenario b

The table (see Table 15) indicates the social surplus value and additional social costs for the various congestion management methods. The minimal costs of congestion are equal to no less than 71.000 Euros per hour in this case: this is the opportunity cost experienced by society of not having sufficient transmission capacity.

Table 16: Surplus and additional costs of congestion for scenario b

Surplus unconstrained dispatch (€ million / hour)	**optimal dispatch** (€/ hour)	**counter trade** (€/ hour)
17,453	70766	74888

Discussion of counter trade costs

In this scenario, counter trade is also more costly than in the previous case, because more transmission lines are bound by their limits. At three thousand Euros per hour, this amounts to and increase of at least 4,2% compared to minimal congestion costs under an optimal dispatch. In practice, managing the constraints on two consecutive links within the Netherlands (between nodes 1, 2 and 4) may be difficult and dependence on generators, e.g. in node 2 may lead to the risk of increased market power.

Table 17: Nodal and national prices for scenario b – Dutch nodes

Node	**1**	**2**	**4**	**5**	**6**
price optimal dispatch (€/MWh)	34,6	39,1	39,8	35,9	41,1
price counter trade(€/MWh)	37,2	37,2	37,2	37,2	37,2

The significant differences in generation between nodes are also reflected in greater differences between nodal prices, as can be seen in the tables 16 and 17: within the Netherlands, prices could diverge by around 6 euro/MWh: more than 10% of the unit cost for power. National price zones effectively smooth these differences over all consumers.

Table 18: Nodal and national prices for scenario b – German nodes

Node	**7**	**8**	**9**
price optimal dispatch (€/MWh)	22,9	39,4	42,1
price counter trade (€/MWh)	38,8	38,8	38,8

Table 19: Nodal and national prices for scenario b – French and Belgian nodes

Node	**10**	**11**	**12**
price optimal dispatch (€/MWh)	47,1	43,9	43,7
price counter trade (€/MWh)	45,5	45,5	43,8

Scenario C: Wind in the west and high CO_2 price

This scenario was designed with the idea of Dutch-German exports leading to congestion. It includes 5.000MW of offshore wind power in Ijmuiden (node 5) and much less in the north (400MW) while the price of CO_2 permits is doubled (to 40 Euros / tonne) to make gas fired power cheaper than coal power in the merit order.

However, as can be seen from the arrows in denoting links which would surpass capacity limits in the unconstrained dispatch (see Figure 14), the model output does not conform to this idea. Instead, exports from Germany to the Netherlands are limited in scope, and power flows from the Netherlands to the south increase.

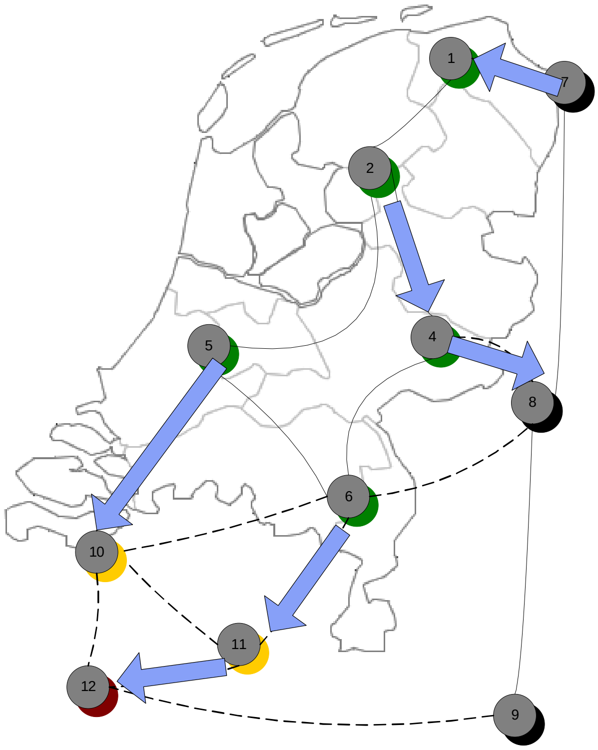

Figure 14: Flows exceeding transmission capacity given unconstrained dispatch for scenario c

The result is that congestion costs resulting from transmission capacity limits are estimated to be quite modest at three thousand Euros per hour – in other words, congestion is comparable in order of magnitude to the base case.

Table 20: Surplus and additional costs of congestion for scenario c

Surplus unconstrained dispatch (€ million / hour)	**optimal dispatch** (€/ hour)	**counter trade** (€/ hour)
16,572	3364	3569

A closer look at possible causes of this somewhat unexpected outcome has formed part of the research. The fuel mix in the Netherlands and Germany is discussed in detail in Annex 10. The effect of the linear supply curves is to smooth the transition between the price of gas and coal fired power within the German market, thus reducing the incentives to trade from west to east. This explains the lower than expected trade between Dutch suppliers and German consumers. Annex 9 addresses the errors involved in approximating the French supply curve using a linear function, and shows that this in contrast overestimates the price of some of the large amount of nuclear power, thus somewhat increasing the incentive to export to Belgium and France.

Table 21: Nodal and national prices for scenario c

Node	**1**	**2**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
OD price (€/MWh)	47,7	47,2	48,5	46,5	48,9	46	48,6	49,4	51,1	49,9	49,9
CT price (€/MWh)	47,15	47,15	47,15	47,15	47,15	48,5	48,5	48,5	50,5	50,5	49,9

The nodal prices (see table 9) reflect the significance of the power produced in node five for the rest of the country. This node represents a large share of capacity in each scenario, as it includes the industrial areas around Rotterdam and Amsterdam, where many existing fossil plants are located. This concentration is increased in scenario C as a result of the large amount of available wind power produced there. By contrast, the production in the north German node exerts less influence on German national prices.

Scenario D: French nuclear power supply shock

This scenario is aimed at investigating the effects of a sudden decrease in supply, which could lead to congestion between the north and the south of the CWE region. French nuclear capacity is assumed to be reduced by 1.450 MW[32], while demand is fixed to remain the same.

Thus, the supply curve for France becomes a lot steeper (c=0, 0006). Supply input parameters for other nodes are the same as in the base case scenario.

These changes lead to a large increase in the size of the flows occurring as France imports more than 10.000MW when flows are unconstrained (see Figure 15) – more than 10% of total electricity consumption. This is because the change in the supply curve cost parameter is spread out over all the production, making imports more competitive than French generation.

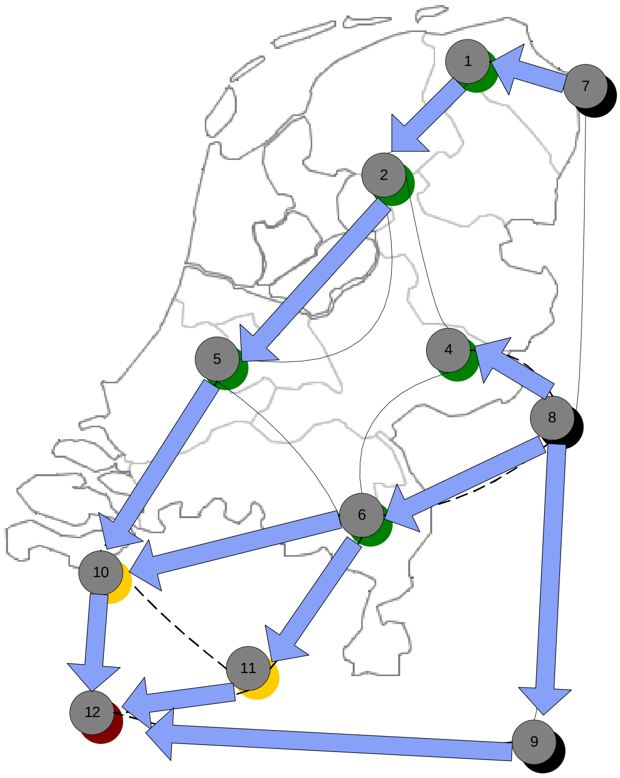

Figure 15: Flows exceeding transmission capacity given unconstrained dispatch for scenario d

However, when interconnector constraints are binding much less congestion occurs within the Dutch network.

Table 22: Surplus and additional costs of congestion for scenario d

surplus unconstrained dispatch (€ million / hour)	**optimal dispatch** (€/ hour)	**counter trade** (€/ hour)
16,931	39644	40946

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[32] This is consistent with one of the largest capacity nuclear plants in France (which are rated at 900, 1300 and 1450 MWe depending on their design)

Table 22 shows that the resulting congestion costs are around 40.000 Euros per hour: smaller than those represented by scenario B, but are larger than in the base case scenario. Tables 23, 24 and 25 show the nodal and national prices that result.

Table 23: Nodal and national prices for scenario d – Dutch nodes

Node	**1**	**2**	**4**	**5**	**6**
OD price (€/MWh)	41,3	42,3	42,5	40,8	45,1
CT price (€/MWh)	41,8	41,8	41,8	41,8	41,8

Table 24: Nodal and national prices for scenario d –German nodes

Node	**7**	**8**	**9**
OD price (€/MWh)	36,7	42	47
CT price (€/MWh)	42,9	42,9	42,9

Table 25: Nodal and national prices for scenario d –French and Belgian nodes

Node	**10**	**11**	**12**
OD price (€/MWh)	49	47	42[33]
CT price (€/MWh)	48,4	48,4	42,7

The additional costs of counter trading are again relatively small within the Dutch network, amounting to one thousand Euros per hour – around 2,5% of the congestion cost.

4.2 Interpretation of the results and zonal pricing within nations

What do the results described in section 4.1 tell us about the suitability of congestion management methods within and between the Netherlands and Germany? This section discusses the answers to that central question. This is done first by looking at the combined results presented in section 4.1. Next, this analysis is extended by addressing the consequences of the application of price zones within national networks based on additional model runs. Finally, some specific sub questions formulated in chapter one are dealt with, as the effects of increased transmission capacity and the potential for TSOs to avoid counter trade within their countries by declaring lower interconnector capacity are investigated.

[33] The demand in France is constrained and must be met, so this figure may be a little misleading (as it is calculated based on an unchanged demand curve. In reality if the market were reflective of the situation the wholesale price would be likely to increase steeply, as costs are estimated at closer to 50 euro/MWh although these incidental prices would not necessarily be immediately passed on to consumers).

The economic effects of zonal pricing given market coupling within CWE

The results for various scenarios under unconstrained dispatch (UD) show that for the base case scenario, congestion within the national networks is limited, given the developments considered most likely to occur and the model assumptions such as the available transmission capacity margins and the way the market works.

Within the Netherlands, the most likely location for congestion to occur according to the model is in the north of the country, especially if wind power is deployed in large quantities in the north, which confirms the findings of existing load-flow studies by the Dutch TSO Tennet (2008b). Congestion on the interconnectors remains a more likely occurrence in the other scenarios considered.

Congestion occurs under the conditions represented by the other scenarios, but tends to manifest itself mainly on the interconnectors between countries and in the form of small deviations above the limits of network capacity, which can be prevented through counter trade at relatively low costs, amounting to thousands rather than hundreds of thousands of Euros per hour. This could justify a choice for applying this form of congestion management, if policy makers are convinced that these scenarios cover potential causes of congestion.

The scope of the congestion that needs to be managed is larger given scenario B – around seventy thousand euros per hour. This scenario features significant wind power construction in the north of the Netherlands coupled with strong wind conditions. Given such a scenario, nodal prices would diverge significantly within both the Netherlands and Germany (by more than 10% of unit costs for power).

Both the absolute cost of managing such congestion using counter trade, and the difference in costs between methods such as national price zones or nodal pricing increase under those circumstances, from a range of thousands to tens of thousands of Euros. Relying on counter trade under these conditions could therefore be more difficult to justify if wind power is indeed expanded at a high rate, and located mainly in the north of the country. These results are also displayed graphically in the graph (see Figure 15a).

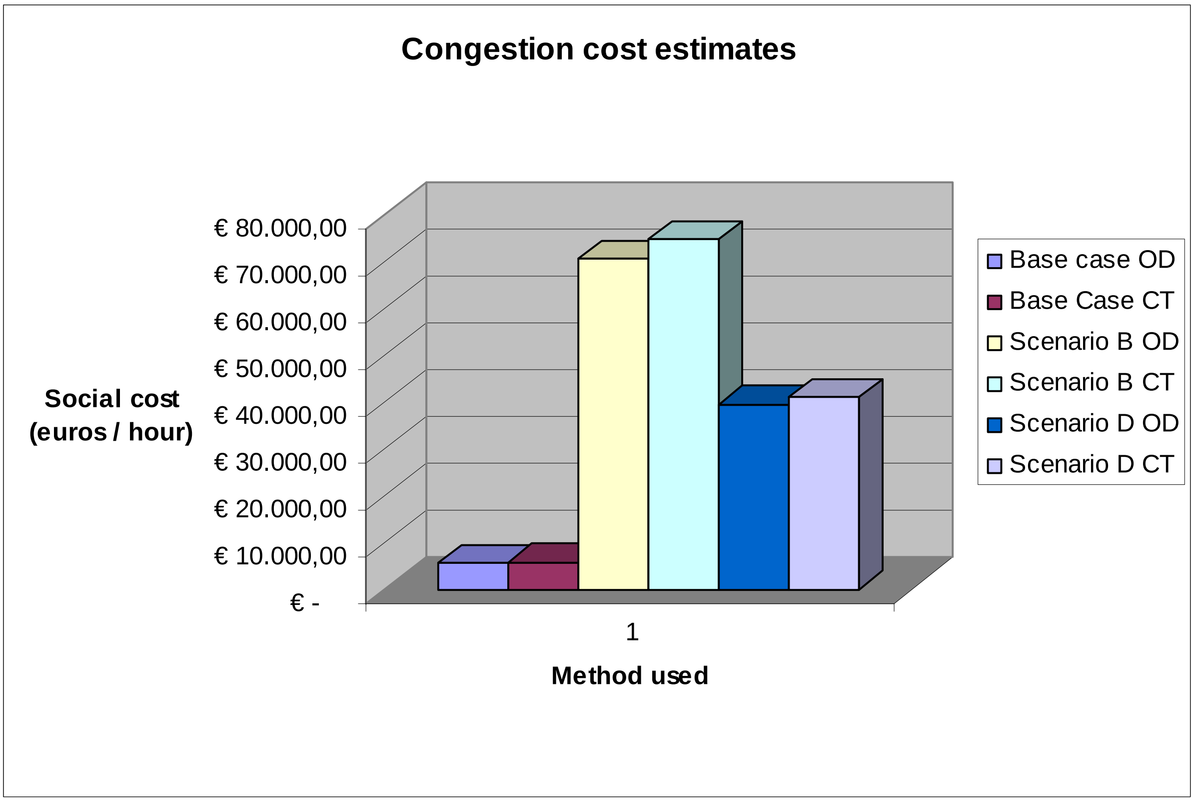

Figure 15a: 3d graph showing congestion cost estimates for base case, scenarios b and d

Furthermore, the amount of suitable thermal generation capacity for counter trading to manage such congestion in the east of the country may also be limited due to the relatively small amount of power stations located there. This could increase concerns related to the potential for market power abuse in relation to the bids for supply capacity to be constrained on during counter trade.

Thirdly, the results reveal that under these conditions, both the direction of electricity transport and congestion can be identified as similar within the German network. These similarities between export constraints in neighbouring countries therefore resemble the situation investigated by Bjørndal and Jornsten within Norway and Sweden. The next section discusses whether their conclusions regarding the ability of price zones to approach the level of congestion costs which could be potentially achieved using nodal prices can also be shown to apply within the CWE region.

Zonal pricing within the Netherlands and Germany

These findings justify more thorough investigation of the potential for applying zonal pricing as a form of congestion management within the Netherlands and Germany. Two possible zonal boundaries are considered within the Netherlands (Nl2, Nl3), and one within Germany (De2). A situation with a single cross border price zone is also taken into account (Nl/De/Nor). These zonal configurations are shown graphically in Figure 16.

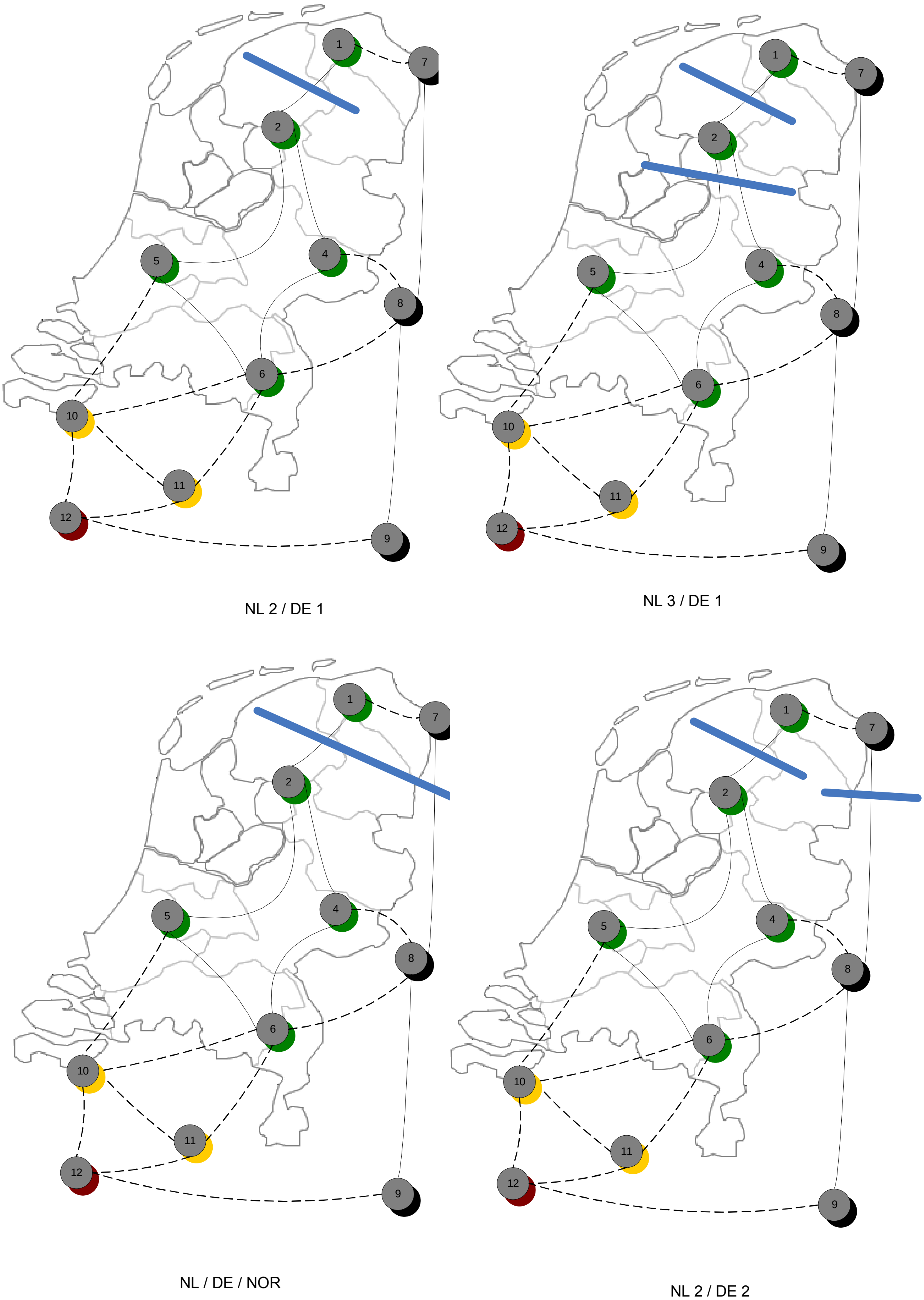

Figure 16: Possible price zone configurations for managing congestion in scenario b

The results of running the model given these zonal configurations are shown in the table 26 rounded off to the nearest thousand, while the unconstrained dispatch, optimal dispatch and single national price zones (assuming counter trade) are reproduced in the first three columns as a reference. Prices in each zone are displayed in table 27.

Table 26: Surplus and cost of congestion management using zonal configurations for scenario b

Price zone combination	Unconstrained dispatch	Optimal dispatch	Nl 1/De 1	Nl 2/De 1	Nl 3/De 1	Nl 2/De 2	Nl 1/De 2	Nl/De/Nor
Cost of congestion management (€/ hour)	0	71.000	74.000	74.000	74.000	72.000	72.000	72.000

These results allow answers to be given to the sub question that asks what the effect of price zones within Germany and the Netherlands is on congestion (see Chapter 1). It was already clear from the results reported per scenario that the conditions in scenario B create greater congestion within both the Netherlands and Germany, leading to around ten times higher costs of congestion compared to the base case. Table 26 shows that a reduction in these costs can be gained from the zonal configurations which allow two prices to occur within Germany rather than just the Dutch network. These configurations, shown in the last three columns of table 26 imply congestion cost reductions of around 2000 Euros per hour, or 3% of the social costs of congestion. This equals around 2/3 of the difference between the optimal dispatch achieved using nodal pricing and national price zones which are currently used. The results thus confirm the conclusion of Bjørndal and Jornsten (2008) regarding congestion within the Nordic markets: a limited number of price zones can achieve a reduction in costs that approaches the optimal dispatch result. However, given the fact that the most important reductions were found to result from introducing German price zones, while the German network is highly aggregated within the model, further research would be necessary to say with more confidence which zonal configurations would best serve the CWE region.

The model predicts that the greater differences between the costs of production and the quantity of capacity in the north and the rest of Germany would be reflected in stronger price differences when congestion is managed using methods such as zonal or nodal pricing, as shown in table 27.

Table 27: Zonal prices congestion management using zonal configurations for scenario b

Node	UD (€/MWh)	OD (€/MWh)	NL 1/DE 1 (€/MWh)	NL2/DE1 (€/MWh)	NL3/DE1 (€/MWh)	NL2/DE2 (€/MWh)	NL1/DE2 (€/MWh)	NL/DE/NOR (€/MWh)
1	40,87	34,6	37,215	34,61	34,61	34,61	37,2	29,7
2	40,87	39,1	37,215	37,44	38,4	37,4	37,2	37,4
4	40,87	39,8	37,215	37,44	37,3	37,4	37,2	37,4
5	40,87	35,9	37,215	37,44	37,3	37,4	37,2	37,4
6	40,87	41,1	37,215	37,44	37,3	37,4	37,2	37,4
7	40,87	22,9	38,77	38,77	38,79	22,9	22,9	29,7
8	40,87	39,4	38,77	38,77	38,79	40,2	40,2	40,2
9	40,87	42,1	38,77	38,77	38,79	40,2	40,2	40,2
10	40,87	47,1	45,5	45,5	45,5	45,6	45,6	45,8
11	40,87	43,9	45,5	45,5	45,5	45,6	45,6	45,8
12	40,87	43,7	43,8	43,8	43,8	43,8	43,8	43,8

Increased interconnection capacity

Congestion occurs when there is insufficient transmission capacity to transport electricity between suppliers and consumers. This phenomenon has occurred for quite some time on the interconnectors between national networks, while problems within them are more recent.

One (expensive) policy for reducing such problems and integrating national markets more fully is to invest in additional interconnection capacity. An example of a project that aims to do so is the new interconnector that is planned between Doetinchem and Wesel (Tennet, 2009b). In order to give an indication of the scope for improvement in market outcomes under congestion possible from such changes to the network, the model has also been run several times with 50% additional interconnector capacity between the Netherlands and Germany. The results are shown in the table below, rounded off to thousands.

Table 28: Changes in social costs of congestion for scenarios with higher interconnection capacity

Scenario	**optimal dispatch (congestion costs in € / hour)**	**counter trade (congestion costs in € / hour)**
Base case	6000	6000
Base case (increased interconnection capacity)	5000	5000
Scenario B	71.000	74.000
Scenario B (increased interconnection capacity)	66.000	69.000
Scenario C	3000	3000
Scenario C (increased interconnection capacity)	3000	3000
Scenario D	40.000	41.000
Scenario D (increased interconnection capacity)	38.000	39.000

The outcome of these model runs (see table 27) shows that increasing interconnection capacity can help alleviate some but not all congestion. For scenario B, representing increased wind power in the north, doing so gives somewhat larger benefits compared to the optimal dispatch with lower capacity, but even though congestion between the networks has been cleared by doing so, minimal congestion costs due to constraints within the borders of national networks are still 66 thousand Euros per hour.

Incentives for the TSO to declare lower interconnection capacity

Earlier research by Bjørndal and Jornsten (2008) suggested that there could be an incentive for TSOs to avoid congestion within a national network by declaring lower maximum capacities on the interconnectors between countries. This can be investigated by running the model again for a lower capacity on the northern interconnector with no limits to internal transmission. The flows in the congested links (1,2) and (2,4) as well as on the interconnector in the north of the Netherlands are shown in table 28 for both the normal capacity and 50% lower capacity.

Table 29: Flows through congested Dutch transmission links for scenario with increased wind power under reduced interconnection capacity

Link in model	interconnector normal capacity (MW/hour)	interconnector ½ capacity (MW/hour)
1-7	-825	-412
1-2	4664	4388
2-4	2765	2683

The reductions in the Dutch links show that while this tactic will reduce the need for counter trade within the Netherlands, it will not be sufficient to avoid it altogether. Social surplus falls significantly (by around 10000 Euros per hour) given the reduction in interconnection. Other policy options which are conceivable besides congestion management measures could include changes to the operational practice of the TSO, such as letting go of strict contingency based safety margins for the amount of power that may be transported through the grid, however this falls outside of the scope of this research.

Translating the estimated congestion costs into a yearly cost

The model results described in sections 4.1 and 4.2 can indicate what the level of congestion could be per hour. They suggest that congestion is most significant if wind power is deployed in the north and high wind conditions occur during peak load hours –as is the case in scenario B. However, in order to gain a better understanding of what this figure means on a yearly basis, an attempt has been made to estimate the range of hours during which these circumstances occur may within a normal year.

The number of hours in which high wind conditions occur was estimated by looking at the windex indicator for wind conditions per month over the last three years, and then multiplying this number by the percentage of hours during which peak load occurs as is described in Annex 12. The resulting numbers are reported in table 30, and multiplied by the congestion costs estimated for scenario B and the base case[34] to give a (rough) estimate of the scope of yearly congestion costs, which are in the order of tens of millions of euros.

However, it is important to note that the Windex is a rough indicator, which is based on existing wind farm data. Furthermore, large variations in wind speed can occur between years as can be deduced by the difference between the estimates for the years shown. A simulation-based approach at a higher level of detail would therefore be necessary to give a fully confident prediction of the average congestion costs resulting from a given deployment of wind power over its productive life.

Table 30: Rough yearly congestion cost estimate based on Windex indicator (based on calculations using the data from CBS, 2009)

Year	Hours with high wind + peak load	Congestion costs scenario b (€/ year)	Congestion costs base case (€/ year)
2005	547,5	€ 41.001.180	€ 33.397.500
2006	1095	€ 82.002.360	€ 66.795.000
2007	547,5	€ 41.001.180	€ 33.397.500

4.3 Conclusions

Chapter three of this thesis introduces a model which allows the consequences of various congestion management methods to be quantified. This chapter describes the results of running that model for various scenarios, representing plausible combinations of conditions under which congestion may be assumed to occur within and between the electricity transmission networks of Germany, the Netherlands, Belgium and France.

Economic effects of different congestion management methods

The results show that given the assumptions and input of the model, the direct costs of managing congestion under most scenarios are relatively limited compared to the total costs of producing electricity. This confirms that counter trade within national networks investigated could indeed be a feasible policy option for managing congestion in the medium term (the model considers developments until 2014).

The most significant congestion was found when a combination of strong wind development located in the north of the Netherlands and Germany was combined with windy conditions. The costs of network limitations under those conditions for consumers and producers are estimated to amount to at least 70.000 Euros per hour. Given this scenario, the counter trading necessary within the Dutch network was estimated to be both more extensive in scope and higher in cost – around 3.000 Euros per hour more, increasing congestion costs by at least 4% compared to a situation with nodal pricing.

[34] The base case costs are based on full rated wind capacity

Rough estimates of the yearly costs of such congestion suggest these could run into tens of millions of euros. Given the incidental nature of the wind conditions considered, expansion of the network to fully transport all the flows desired by that market outcome may not be justified by the investment cost required. Performing the necessary cost-benefit analysis to support or reject such decisions with confidence falls outside the scope of this research, and would have to take into account the other issues such as the non-financial benefits of renewable energy.

The fact that congestion must be alleviated on several consecutive links in scenario B also suggests that some generators may become unmissable - particularly between the north of the Netherlands and the centre. This means that market power could become a concern in such circumstances. As noted in chapter two of this thesis, different methods for congestion management offer the potential for strategic behaviour by market participants. This suggests that such situations may merit attention by the market regulator if and when these conditions occur.

Zonal pricing within the Netherlands and Germany

Investigation of various possible zonal pricing configurations suggests that the greatest gains in surplus result from implementation of zonal pricing within Germany rather than within the Dutch network. Given two or more price zones in Germany, around 2/3 of the additional increase in costs to consumers and suppliers could be avoided – an outcome close to the minimal congestion costs achieved using nodal pricing.
The results thus confirm the conclusion of Bjørndal and Jornsten (2008) regarding congestion within the Nordic markets: a limited number of price zones can achieve a reduction in costs that approaches the optimal dispatch result. This suggests that it is worth investigating the feasibility of implementing such price zones if developments related to generation capacity close to those described in scenario B are realized – a suggestion also made in a qualitative research paper discussing the introduction of flow-based market coupling by Smeers (2008).

Interconnection capacity

Investigation of expansions to interconnection capacity suggests that this is at best a policy that will allow the alleviation of some, but not all potential congestion. In the scenarios investigated, congestion will remain a problem within national networks, even if constraints between countries are eliminated through investment in interconnectors. As technical data concerning the characteristics of such new transmission infrastructure was not available however, more detailed load-flow studies could be employed to give greater confidence in these results.

Comparison between model results and the existing academic literature

Notable work by Bjørndal and Jornsten (2007, 2008) suggested that counter trade costs for the Scandinavian countries represent a greater proportion of minimal congestion costs compared to the results found here – for some scenarios up to 38% of additional congestion cost Bjørndal and Jornsten (2007, page 1985). This could be the result of more precise modelling

of the differences between base and peak electricity supply costs – these authors suggest their supply curves were based on information gained from discussions with actors in the field. Another possible reason is that the variations in available hydropower are larger than the causes of congestion assumed in this research, such as the high wind power studied in scenario B.
This research is consistent with the findings of Bjørndal and Jornsten (2008) in suggesting that correctly chosen zonal boundaries allow an economic outcome that is not far removed from that achieved using nodal pricing. A difference is that in this research such congestion was more strongly related to one of the countries – Germany. This is probably the result of the larger amount of wind power deployed in the north of Germany compared to the Netherlands. The research is consistent with that of Leuthold et al. (2008) suggesting that the most significant congestion within Germany is on a north-south axis.

More detailed work on wind energy in the Netherlands by Ummels (2009) suggests that situations where there is low demand for electricity may be even more problematic than when peak load occurs. The limited scope for modelling ramping up or down limits for coal-fired power plants makes it difficult to reproduce those particular conditions using the model described in this research. On the other hand, this research includes domestic transmission line limits rather than just interconnectors as possible bottlenecks. This could be the reason that congestion during peak load hours is found to be more significant in the results described in this thesis. A combination of the spatial detail of the research described in this thesis, and the temporal scope considered in that dissertation, may be necessary before confirming or rejecting the findings of either study is possible relating to the potential for congestion resulting from wind power during peak demand periods.

The congestion resulting from accelerated wind power deployment in the north of the country is consistent with the results of studies aimed at investigating the costs of wind park locations (Min Ez, 2009). This research reinforces those findings, by suggesting that this phenomenon becomes more problematic when wind in the north of Germany is taken into account.

Putting the model results into perspective

The sensitivity of the model to variations in the input was evaluated by varying the level of the parameters used (see Chapter three). Although changing some of these parameters, such as the steepness of the demand curve and the available wind capacity, affected the magnitude of the congestion, the general behaviour of the model was found to be relatively robust.

It should be kept in mind that these outcomes should be considered within the context of the assumptions involved in building the model. These impose limitations as to the scope of reality which may be modelled, such as the lack of strategic behaviour by electricity suppliers. Furthermore, any model that attempts to predict the future is liable to uncertainty.

The results can therefore be best interpreted as a reference which may help to inform part of a more complete judgment relating to the suitability of congestion management methods, rather than as a substitute for such a judgment.

5 Conclusions, reflection on the chosen research methodology and advice to policymakers

This thesis describes research performed in order to assess the relative suitability of various methods for managing congestion within and between the Netherlands and Germany. This chapter describes the most important findings of the research. The first (5.1) section briefly discusses the methodology applied, and its limitations. The next section (5.2) returns to the research questions, describing the conclusions that can be formulated based on the activities described in this thesis. Finally, the chapter and the thesis are concluded by section 5.3, which reflects on the implications of the findings for policy makers and gives recommendations for future research that may further inform both policy and science with regard to the topic of managing congestion on the networks for electricity transmission.

5.1 Methodological choices and limitations

A study of the relevant academic literature formed the basis for the overview of policy alternatives and the criteria with which to assess their suitability, allowing answers to be formulated to questions 2a and 2b.

Public and scientific sources were consulted in order to form a picture of relevant issues related to congestion management that can be deduced from existing international practice. The qualitative overview thus given was limited in scope due to the constraints of available time and resources. Although the theoretical literature on congestion management is extensive, it is the view of this author that the available empirical data concerning its effects are somewhat disappointing by comparison.

The main body of work described in this thesis relates to a quantitative model which was built in order to assess the consequences of congestion management methods within and between the Netherlands and Germany. Building on a series of assumptions and data, a 'DC' load-flow model was constructed and run for a number of plausible congestion scenarios. These results and their interpretation form the basis for the answers formulated to research question 3, which asks what the economic consequences of the choice between congestion management methods will be.

Considering the technical and economic scope of the systems modelled, it is not surprising that significant simplifications are inherent to the model used. Where possible, these have been made in such a way as to give a conservative assessment of the potential congestion management costs. A sensitivity analysis has also been performed. This shows that the magnitude of the results may change if some of the input is varied, but confirms that the general behaviour of the model is relatively robust.

The data that serve as input for the results that were reported are based on knowledge of the current situation and the best estimates of future developments available at the time of writing. Nevertheless, it would be advisable to interpret the results as a rough estimate of the market potential and the order of deviations from this given different congestion management approaches, rather than as an accurate prediction of likely events.

5.2 Answers to the research questions, outcomes and conclusions

This section discusses the findings of the research from the perspective of the research questions. As noted in chapter two there are multiple different aspects of the effects of any congestion management method. Although this research focuses on the immediately visible flows of electricity and the short term economic consequences, the long term shifts in investment behaviour and more political questions related to the feasibility of complex institutional systems such as nodal pricing, and their potential for redistributive effects, may also be relevant in assessing suitability of policy alternatives. Multiple possible methods for managing congestion are possible in theory, and different approaches are applied throughout the world. Some take place closer to the real time dispatch of power plants, while other methods based on allocation are typically used at least a day-ahead and demand more complex institutions such as power exchanges.

The relevant alternatives for the Netherlands and other countries within the CWE region that can be applied to interconnectors are limited by European legislation. This only allows for capacity allocation using market-based methods such as explicit and implicit auctions. This research focuses on counter trade and implicit auction approaches, which are seen as the most likely alternatives for implementation within and between the Netherlands and Germany.

The central research question formulated in chapter one was:

What are the economic effects of introducing zonal pricing within and between the Netherlands and Germany to manage congestion?

This thesis describes research aimed at investigating this question based on a quantitative model. The model is based on a simplified representation of the market assuming perfect competition between electricity suppliers and an aggregated representation of electricity transport over the high voltage network, assuming a lossless linear approximation of transmission known as a 'DC' model of electricity flows. Assumptions about fuel price developments and investment form the most important input for the model. This model allows the costs of electricity production, flows of electricity between locations and the short-term economic consequences of methods for managing congestion resulting from management of congestion using different methods to be estimated based on differences in such costs for consumers and suppliers of electricity.
The economic effects of introducing zonal pricing within and between the Netherlands and Germany to manage congestion differ depending on the developments assumed and the zonal configuration chosen.

The minimal costs of congestion were estimated for several scenarios by finding an optimal dispatch: this effectively creates a price zone for each node within the national networks. The estimates for the costs of congestion ranged between €6000 and €71.000 per hour. The increases in congestion management cost compared to optimal dispatch were greatest when dispatch of the most efficient generation was limited by the need to maintain national price zones using counter trading, leading to additional costs of around €1000-3000 per hour, in the order of 5% of congestion costs. Using zonal pricing, most of these additional costs could be avoided.

Rough estimates of the yearly costs of such congestion suggest these could run into tens of millions of euros. Given the incidental nature of the wind conditions considered, expansion of the network to fully transport all the flows desired by that market outcome may not be justified by the investment cost required. Performing the necessary cost-benefit analysis to support or reject such decisions with confidence falls outside the scope of this research, and would have to take into account the other issues such as the non-financial benefits of renewable energy.

The margin for error within this estimate is quite high, as the potential for errors in model inputs such as fuel prices, limitations in technical data and simplifying assumptions are significant when modelling several systems which are both complex and as large scale as national electricity markets and transmission networks. A sensitivity analysis and several scenarios allow some of the inherent uncertainty to be assessed. In this case, the sensitivity analysis suggests that the behaviour of the model in terms of flows and congestion is relatively robust when parameter input is varied.

What is the impact on congestion on the Dutch electricity network resulting from one or multiple electricity price zones in Germany?

Zonal pricing within the Netherlands and Germany was investigated in greater detail for scenarios involving increased wind power in the North. Implementing price zones in the Netherlands alone did not significantly reduce congestion management costs. Improved outcomes were found only when prices were allowed to reflect the surplus of cheap wind power in the north of Germany and the lack of transmission capacity within the German network. Implementing two price zones allowed estimated congestion costs to fall to within €1000 of the results given an optimal dispatch – equivalent to around 2% of congestion costs.

What are the potential incentives for TSO to save money by 'moving' congestion (by declaring a low transmission capacity) from the national network to international borders, if the national network represents a single price zone?

The research suggests that while application of this tactic by the TSOs in the Netherlands and Germany can reduce the need for counter trade somewhat, it will not be sufficient to avoid it altogether. Social surplus falls significantly given such a reduction in interconnection, while prices for electricity in the Netherlands rise by around 0,5 Euros /MWh.

How would increased interconnection capacity affect congestion within the Netherlands?

The research suggests that interconnection capacity increases could increase welfare by removing some but not all congestion. In the most congested scenario, increasing interconnection by 50% yielded a net benefit to society of 5000 Euros/hour. This is equal to around 7% of the congestion cost. However, it is important to note that it is difficult to know with certainty how an increase in physical transmission capacity between national networks translates into capacity available for cross-border trade under the current bilateral explicit auction system using ATC values between countries. In order to achieve the increased capacity investigated in relation to this question, higher investment may therefore be necessary.

What can be learnt from the existing practice of zonal pricing and other congestion management methods?

Zonal pricing is practiced within the Nordic electricity markets. A qualitative analysis of developments in the recent past suggests that scope for policy disagreements between countries is likely to remain, even when markets are regionally integrated and electricity market institutions resemble one another more closely than is the case in the CWE region.

Congestion management policy choices will change rather than reduce the complexity of decisions relating to market operation, regulation and transmission investment. Cooperation and joint research between neighbouring countries with differing systems can allow such topics to be addressed based on a more mutual basis.

The joint Nordic transmission planning and allocation of congestion rents to projects, including strengthening of lines within national networks, is more reflective of the reality of electricity networks than current practice in the CWE region, which is considerably more fragmented.

5.3 Recommendations to policymakers and promising topics for future research

At the time of writing, congestion is still seen within the Netherlands as a temporary phenomenon which ought to be solved as soon as transmission infrastructure investments ‘catch up’ to changes in electricity generation and consumption. Given the shorter lead times in the construction of generation capacity than in transmission infrastructure and the lower level of coordination compared to the situation before unbundling and market liberalization, this is unrealistic.

A shift in perspective is necessary in order to recognize that society is best served by a network that is sufficient for transport of power most rather than all of the time. This need not mean that new connections need to be delayed, as was the case in the past, if the institutional structure of the electricity system is changed to reflect this and includes efficient solutions to manage congestion if and when it occurs. A suitable policy for congestion management within the Netherlands and Germany should provide this solution. The answer to the question of what a suitable method for congestion management for the coming years will be is in the end a political one, but the choice can be informed by the results found for different zonal pricing methods.

This research has investigated several plausible scenarios for congestion in 2014. The fact that the scenario showing the greatest scope for congestion is based on the implementation of wind power shows that this could become an important future driver of policy. This is especially the case if renewable power is given priority access to the grid over fossil fuelled plants as is part of proposed policy in the Netherlands and is the status quo in other CWE countries (Deloitte consulting, 2007).

The outcomes of the model runs, given relatively conservative assumptions such as the presence of a perfectly competitive market, suggest that a relatively modest policy based on counter trade similar to current proposals would not present very large direct costs. As long as congestion is expected to be incidental, rather than structural, and limited in scope this may be considered a suitable approach.

Despite this conclusion, policy makers are advised to maintain a critical perspective regarding the capacity of the Dutch transmission network to deal with large quantities of wind power if this is located in the north of the country. In order to be conservative in their conclusions, such studies should take into account the limitations regarding transmission capacity within the Netherlands, and the differing amounts of capacity made available on the interconnections across borders. As is noted by Smeers (2008), TSOs have an incentive to protect themselves against having to interrupt transactions that may physically infeasible. Operational values for the CWE region (ATC) are thus often lower than NTC values, which are often assumed in research models.

In situations where multiple consecutive transmission lines become congested, such as scenario B investigated in this research, some parties in northern nodes may become irreplaceable for providing the necessary capacity to be constrained on or off. Given the correlation between pivotal supply and higher prices identified in the 2008 market monitor for the Dutch electricity market ((NMA, 2009a) forthcoming), this combination of events brings the risk of potential for market power abuse. The regulatory authorities are therefore advised to actively investigate such situations if counter trade is used for congestion management, for example by comparing the market outcomes in when such cases to model based predictions of what the outcomes should be given perfect competition.

Pricing scarce capacity using nodal pricing would ensure that these costs could be avoided, and that signals are sent to the owners of generation capacity that reflect the costs of their location for the network. However, while choosing for such a system may lead to an efficient market on paper, in practice the transition to a more complex set of institutions may not be worthwhile if congestion occurs infrequently.

This thesis also describes the predicted results of implementing possible price zones within the Netherlands and Germany. The quantitative results from the model for the scenario with the greatest level of congestion suggest that these allow for outcomes that are close to those given nodal pricing. These benefits are more strongly linked to the disparities in production and demand for electricity in Germany than the Netherlands. Dutch policymakers are therefore advised to place this issue on the agenda in their bilateral discussions with German counterparts, and to advocate either the further expansion of German north-south interconnection capacity or otherwise the implementation of two or more price zones reflecting transmission scarcity.

Regardless of the congestion management method, policymakers on both sides of borders would do well to recognize that the flows in electricity networks defy neat division into national borders. Decisions related to the regulation of transmission infrastructure investment, its operation and to congestion management in particular in any one country will therefore affect what happens elsewhere in the region. In the long term, a consistent regional approach that recognizes this fact offers the best foundation for making the necessary trade-offs related to electricity policy and the incentives offered to actors within the electricity sector.

Future research could increase confidence in these results, and the recommendations based upon them, by improving the input related to the two largest countries within the CWE region, France and Germany. Gathering data for these systems and markets proved to be relatively difficult, while their size translates into a greater relative influence on the results. The results of the research described in this thesis have benefitted from being able to use the data calculated by Tennet describing the spatial division of demand within the Netherlands. Finding and integrating such data for the entire CWE region to a similar degree of accuracy would increase confidence in the external validity of the results for the other countries.

A more accurate market representation could be achieved by using more complex mathematical functions to represent supply and demand curves, and by more complex multi-actor models that could include imperfect competition. Such changes to the model would allow the consequences of market power abuse to be more accurately predicted, and could potentially strengthen the arguments related to market performance for an eventual shift to a congestion management approach based on implicit auctions. It is likely that the flows resulting from the differences in input between the scenarios would then become greater, as price increases and thus shifts in the power plants dispatched would be greater following small changes in the merit order.

The electrical infrastructure could be more accurately modelled by calculating the typical losses of electricity during transport and the scope of reactive power within the model rather than using rough estimates of safety margin. Such an exercise would be more accurate if the scope of the model were extended to include network components such as transformers and lower voltage distribution networks. By adapting the model in order to allow for the simulation of effects over longer timeframes, such as the ramping up and down of power plants, more accurate dynamic behaviour could also be considered over timeframes covering several consecutive hours within a given day. Specific attention could be devoted to the margin of capacity truly reserved for contingencies in practice. A full model of the investment decisions involved in the electricity market would allow for dynamic behaviour to be investigated, and allow for a better judgment to be made concerning the influence of pricing signals for investment decisions in power plants.

The results of any such model would be easier to interpret, given sound research that would indicate the frequency with which various possible forms of congestion occur. In theory it should be possible to do this for all conceivable causes of such congestion, including incidental reductions to generation capacity, transmission capacity and changes to the merit order following from shifts to variable costs. These could then be coupled with estimates based on a model such as the one described in this thesis. Such a study should ideally be conducted on a regional basis, and repeated with a similar frequency to existing supply adequacy forecasts.

In order to be able to assess the congestion costs associated with off-shore wind power accurately, the spatial scope of this thesis should ideally be combined with the temporal scope described by Ummels (2009), and used as the basis for a simulation-based approach in order to allow estimates over longer periods, such as the productive life of windparks.

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Preface to the annexes

The research described in this thesis deals with the topic of congestion management. This subject is investigated using a quantitative policy model which can help to inform policymakers by estimating the order of magnitude of different congestion management methods. The main text of the thesis contains chapters describing the relevant policy framework (2), the model and the methodology applied(3), the most important results found using the model (4) and the conclusions which follow from the research results.

The annexes contain additional information, which may be of use for readers interested in finding out more about the details involved in the methodological approach applied to the research. A brief overview is given here of the aspects covered by the various annexes, grouped per subject.

Communication of the research

Annex A contains the draft of a scientific article based on the research described in the thesis. Although this article does not contain additional substantive material compared to the thesis, it shows how parts of chapters three and four could be presented for publication within the scientific community. The presentation has been adjusted based on the Utilities Policy journal guidelines for submissions.

Model structure and validation

Annex 1 contains a description of the way in which the equations that form the main part of the model were validated during the initial stages of the research. This annex may serve readers interested in the approach used by helping to understand the mechanics of building network models using software, such as that described in this thesis. **Annex 2** describes the way in which the equations governing the transmission of electricity may be deduced for a given meshed network based on Kirchhoff's laws. **Annex 7** describes the algebraic steps through which these equations can be related to the general formulation of the 'DC' load-flow approximation. These annexes may be of use to readers interested in the application of more general electrical network and circuit theories to research models.

Transmission network

Annex 3 reproduces the results of load-flow studies from the Dutch TSO Tennet, indicating which transmission links in the high voltage network are most at risk of becoming congested over the medium term. This forms part of the basis for the choices made regarding the scope of the model described in chapter three. **Annex 6** describes the way in which the technical data published by Tennet about the high voltage transmission network was used within the model. These annexes may be of interest to those readers who wish to know more about the technical limits of the Dutch high voltage network, and the safety margins involved in its operation.

Electricity markets

Annexes 4 and 5 describe the methodology used to estimate the most important input parameters for the supply and demand curves used in the model. **Annexes 8 and 11** sum up the scenarios investigated in order to deal with the uncertainty of future developments, as described in chapter three and the relevant changes to the parameters. This information may be of interest to readers who are interested in the electricity wholesale market in particular, rather than the transmission network.

Uncertainty within the model and data and the interpretation of the results

Research models aimed at investigating the future of complex and volatile systems, such as the electricity wholesale markets and the transmission networks of several countries involve considerable uncertainty and sometimes a lack of specific data. A sensitivity analysis performed in order to test the robustness of the model results to changes in the input parameters of the model can be found in chapter three. **Annexes 9 and 10** look more specifically at the French and German electricity market assumptions. These annexes may be of interest to readers who would like to know more about the challenges involved in estimating aggregated national data for such large systems. **Annex 12** explains the method through which the results were used to find a rough estimate of annual congestion costs.

Appendix A: Scientific article

Congestion due to wind power in the Netherlands: the cost of inefficient solutions

Attention devoted to congestion management in the Netherlands has until recently been limited to interconnectors. As the transmission network within Dutch borders is expected to be congested more frequently, in future the choice between methods to manage this such as counter trade and zonal or nodal pricing has become more relevant.

This article investigates the additional costs that result from maintaining national price zones within the Netherlands and Germany using counter trading, given varying quantities of offshore wind power capacity and conditions. The results suggest that congestion becomes more relevant if windy conditions and high quantities of wind power deployed in the north are combined. When this occurs, creating two or more price zones within Germany was found to be more effective than in the Netherlands, delivering a result close to the optimal dispatch found using nodal prices.

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Keywords: congestion management, transmission, nodal pricing, counter trade, wind power

1 – Introduction

Much past attention from European policymakers has been devoted to congestion on the transmission links between national electricity networks. European legislation, such as the congestion management guidelines in the electricity market directive (2003/54/EC) and regulation (1228/2003/EC) limit the methods for allocating capacity to market-based approaches such as explicit auctions or market coupling.
Congestion management is becoming now becoming relevant within national networks, partly as a result of the fact transmission infrastructure takes longer to build than generation capacity.

Since the liberalization of the electricity sector and the ensuing unbundling in countries like the Netherlands, this has led to a lag between investment in generation and transmission. Within the Netherlands, congestion is expected to occur in the coming years on the transmission network linking the north and rest of the country (Tennet, 2008a) as different companies have announced planned new investment in generation in the north.

In order to deal with such congestion, several congestion management methods including various forms of counter trade are being considered. (D-Cision / the Brattle group, 2009). The choice is complicated by the fact that the Dutch government also wishes to stimulate off-shore wind power, which could be located in the north of the country, exacerbating expected congestion issues. Licenses have recently been granted for several sites (Ministry for Traffic and Water, 2009). Studies have shown such plants would be best located close to demand centres in the west or south west (Ecofys, 2009) of the country and describe investment in transmission infrastructure to serve needs of the wind power deployment. Recent licenses have also been granted for parks offshore in the north of the Netherlands (see Figure 1) for 875MW of rated capacity (Ministry for Traffic and Water, 2009).

This article describes research in which the costs of inefficient congestion management are quantified using an 11 node ‘DC’ load-flow model, assuming various levels of wind power deployment in the north of the country. Furthermore, the interaction of power flows with the wind power development in the north of Germany is investigated.

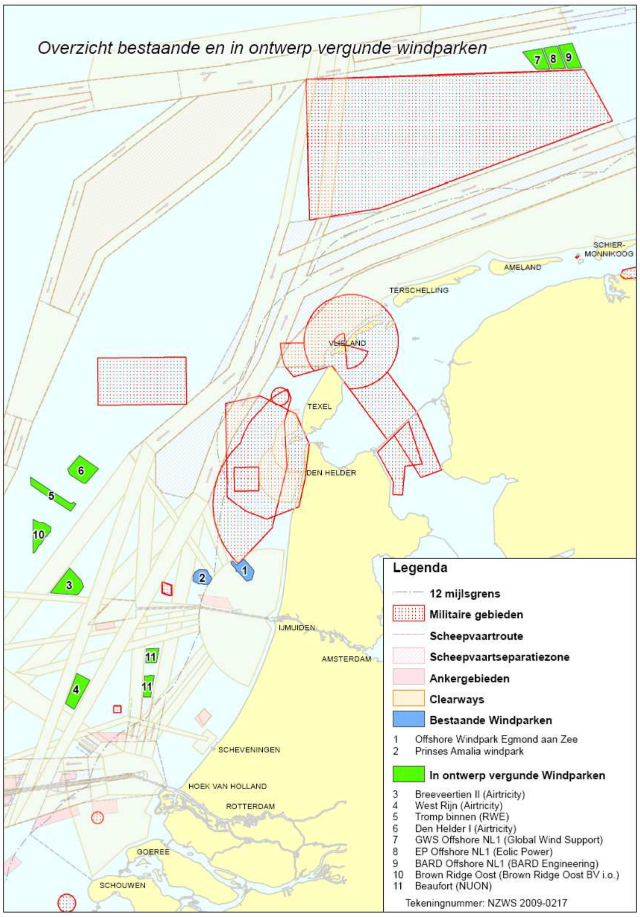

Figure 1: Permits for Dutch wind farms (Ministry of Water and Transport, 2009)

Although multiple forms of congestion management exist in theory, the relevant choices for the Dutch network are limited to redispatch (existing practice), various forms of counter trade suggested by Hakvoort et al (2009) and market splitting, which allocate capacity further ahead of real time and is comparable in effect to the market coupling currently practiced between the Netherlands, France and Germany. (Knops, 2008).

Of the European countries, only Norway has long used zonal pricing, an aggregated form of allocating scarce capacity using implicit auctioning of capacity when congestion occurs. Research by Bjørndal and Jornsten (2008) suggested that certain combinations of price zones could deliver results close to nodal pricing within Scandinavia. The consistency inherent in adopting a market splitting approach within the country, given the region’s (2007) stated goal of market coupling between national markets, seems attractive[35].

This article describes research quantifying the effects of such methods, using a model that can represent both their technical (flows) and economic (the differences in prices, costs of electricity production and the resulting welfare) consequences. For the different methods, the model must be able to determine which quantities of power would be produced at each location, what transport between locations would occur, and the resulting prices.

2- Material and methods: a model allowing congestion to be modelled within the Netherlands and Germany

In order to quantify the differences between different congestion management methods, a model was built that combines simplified representations of both electricity markets and the relevant transmission networks. This section of the article gives a basic overview of the model structure and form. The full version of the model is available online at (*website*).

[35] In addition, the existing EU congestion management guidelines restrict congestion management on interconnectors to market-based methods such as explicit or implicit auctions.

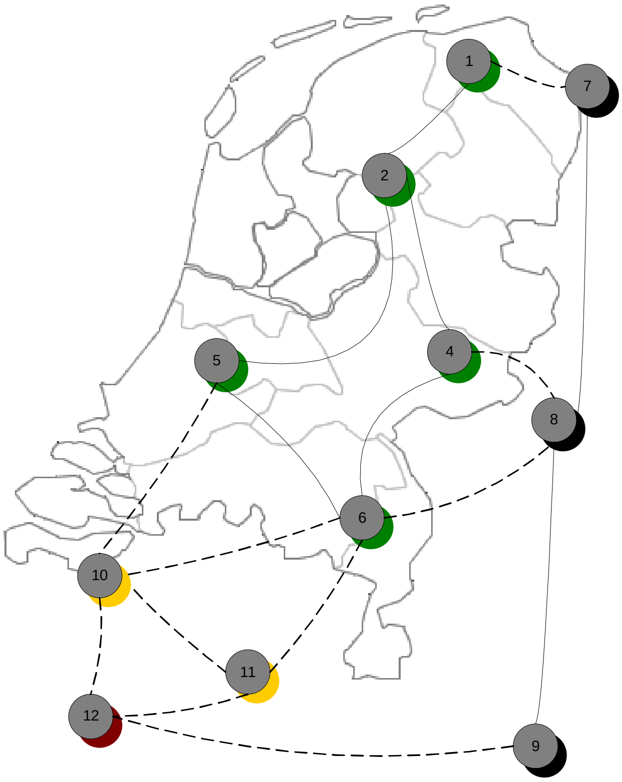

Figure 2: model aggregation

An 11 node network (Figure 2) is used to represent the most important links (380kV) of the high voltage transmission grid within the Netherlands and locations where production and consumption of power take place. While the focus is on accuracy in representing the Dutch grid and power generation, the networks of surrounding countries within the CWE region are modelled in aggregate, to allow for a more realistic representation of cross-border flows. The model described here is based on two central methodological simplifications, relating to the behaviour of the markets and the transmission networks.

2.1 Electricity markets

The electricity markets are modelled based on the assumption of perfect competition under the theory of spot market pricing, first applied to the case of electricity by Schweppe et al (1988). The general formulation of the optimization problem is as follows:

Maximize $\sum \boldsymbol{S(i)} = \int \boldsymbol{a - b*(q_d) - \int c * (q_s)}$ *for all i, where i represents the nodes in the model* (1)

Here S(i) is the surplus per node, while the variables q_d and q_s represent the amount of power supplied or consumed at the node. The parameters a,b and c determine the slope of the inverse demand curve and the supply curves, which are linear.
The first part of the right hand side of the equation relates to area under the demand curve. This represents the willingness of consumers to pay for electricity. The second part on the right hand side of the equation represents the area under the supply curve: the costs of producing the quantity q_s of electricity. The net difference between the two is the surplus S(i). By maximizing the sum of S over all the nodes, the model thus determines how electricity demand can be met at the lowest cost.

Each node can produce and consumer power and export or import power from the grid. The net import or export at a node is represented by the variable q_i, with the following equation:

$$q_s(i) - q_d(i) = q_i(i) \qquad (2)$$

for each individual node i, where the variable $q_i(i)$ *represents the quantity of power injected into the grid when it is positive and withdrawn when negative. The number of such independent equations is one less than the number of nodes in the network.*

Linear curves are used to estimate supply function for the power market at each of the nodes, assuming that these are based on variable costs. Based on data from Tennet on current (Tennet b, 2009) and future power plants (Tennet a, 2008) quantities of available capacity were estimated at each location in the model. In practice not all wind power capacity may be possible to predict far enough in advance to trade in day-ahead markets. The percentage of wind power is therefore varied between 25% and 100% of rated capacity. Power plant variable costs for fossil generators were estimated per fuel type based on fuel costs in the 2008 world energy outlook for 2014 (IEA, 2008), the CO_2 permit price was assumed to be 20 Euros/tonne and power plant efficiencies as described in Appendix A.

Demand is calculated by assuming that national demand would equal total capacity if the price were 0. Predicted demand was estimated based on growth figures from (Tennet a, 2008) and extrapolated from the UCTE's supply adequacy forecast (2008), and entered into the aggregate national supply function described earlier to give a second data point. Demand was then divided over the nodes according to correlation of economic activity with electricity (Tennet c, 2009) and divided over German nodes according to the TSOs' 2013 study (German TSOs, 2008). The parameters describing the demand curves can be found in appendix A.

2.2 Transmission network

A lossless 'DC' load-flow approximation of AC power flows is used. This allows a linear approximation of the power flows to be estimated within an electric network, ignoring reactive power and losses as described in sources such as Wood and Wollenberg, (1996) and Smeers (2008) and applied in previous research by Chao and Peck (1996), Green (1997) and more recently Leuthold et al. (2008). Flows through the network are constrained in accordance with the laws of Kirchhoff and Ohm regarding the conservation of energy and the flow of electricity over parallel paths.

Following the work of Bjørndal and Jornsten (2008), equations were derived as explained in textbooks such as Dolan and Aldous, (1993) which allow these laws to be represented given the 'DC' approximation using a minimal set of equations, for each of the independent cycles[36] in the network. The general form of the equations (2) and (3) ensures flows between the nodes are divided over parallel paths based on their relative reactance:

$$\sum X_{ij} * q_{ij} = 0 \qquad (3)$$

[36] The number of independent cycles in such a network is equal to the number of links less the number of nodes, plus one.

for each independent cycle L within the network, where Xij represents the reactance of each of the links ij within that cycle and q_{ij} is the quantity transported over each link in the cycle

The specific formulation of these equations used in the model can be found in appendix A. Reactance values for the Dutch 380kv network and its interconnectors were based on public data as reported by Tennet and from a previous publication Hobbs and Rijkers (2004) for the aggregate representation of the German links and for interconnectors between Belgium and France.

Overall, balance of the energy in the system is equal to zero, represented by the equation:

$$\sum \boldsymbol{q_i} = \boldsymbol{0} \qquad (4)$$

for the set of all nodes i

Furthermore, the quantity (q_{ij}) that each transmission link may transport are limited to its maximum capacity (q_{max}).

$$\boldsymbol{Q_{ij} <= Q_{max\ ij}} \qquad (5)$$

Where the parameter $Q_{max\ ij}$ represents the maximum[37] *capacity of the transmission link ij.*

Capacity data were estimated assuming a safety margin for contingencies, reactive power and losses is 1/3 of thermal capacity for the Dutch lines. Full parameter data can be found on the website (website).

Finally, binding equations were included that constrain the model so that prices within any price zone are equal:

$$P_d(i) = P(k) \qquad (6)$$

Where P(k) is the variable indicating the price for electricity calculated by the model for a price zone 'k', and $p_d(i)$ represents the set of variables related to the price at the nodes within that price zone 'k' (e.g. the Netherlands).

The model was coded in GAMS (version 23.02). When equations (1) through (4) are solved, the model calculates unconstrained flows through each link and prices which will be equal in each node. Including equations (5) and then (6) allows either nodal or zonal prices to be calculated, for the given transmission limits.

It is important to keep in mind when interpreting the results that the assumptions implicit in the methodology will imply a margin of error. As the future is uncertain, data estimates add to this margin of error. The results should therefore be interpreted as an attempt to represent the developments of the coming years with a significant margin of uncertainty, rather than as a detailed prediction of what will actually happen.
Where possible, this research attempts to give a conservative estimate of social congestion costs. The results can therefore serve usefully as a cautious benchmark of the minimal effects of congestion for the scenarios considered.

[37] In the actual model, two equations are used as the flow variable when assuming a negative value indicates transport in a different direction. The corresponding equation is then the same, but with a negative sign.

2.3 - Scenarios under which congestion may be expected to occur

What sort of circumstances could lead to congestion taking place? The scenarios that have been modelled represent possible both structural developments (the quantity of wind power installed) and the incidental conditions (peak demand and windy conditions). In this article, two situations are compared.

First, a ‘base case’ with 2500 MW of wind capacity located off the western coast of the Netherlands, under 2014 peak demand conditions. This was chosen because it represents the best guess of what is likely to happen, given current policy related to wind power and what is known about developments related to planned investment in generation. Next, more rapid deployment of wind power with 4400 MW of wind power off the west coast of the country, and 1000 MW in the north of the country is considered ('Scenario B')[38]. This is one of the alternatives considered as part of a recent study carried out for the Dutch Ministry of Economic Affairs[39] (Ecofys, 2009). In both cases, the fuel prices for 2014 are based on the IEA world energy outlook for 2008 (IEA, 2008). Planned fossil-fuelled power plants which have been granted connections to the grid are assumed to be realized.

First, the model is run without any limits to electricity transmission, which gives the surplus under Unconstrained Dispatch (UD) and leads to a single price across all the nodes. This can be considered as a quantitative measure of the social benefits of electricity trade for both producers and consumers: a benchmark of the minimal costs of electricity supply. Flows through the network are calculated. Those flows that would exceed the limits of transmission links are displayed graphically using arrows on the transmission links.

Next, the model is run with transmission limits, but without limits on the variation in prices between nodes. The model outcome then conforms to nodal pricing[40], which can be considered to be an Optimal Dispatch (OD). The difference between the unconstrained and the optimal dispatch gives an estimate of what the minimal costs of congestion could be, if scarce capacity were reflected in differing prices for electricity in different places.

Finally, the model was run using a number of price zone combinations within the Dutch and German networks, shown graphically (see Figure 4).

3 – Model results

The results for both scenarios are compared assuming all available capacity is able to produce at 25% of rated capacity. The unconstrained dispatch was 17.26 million Euros per hour in the base case, and 17,27 million Euros per hour for scenario B. Figure 3 shows that the congestion in both scenarios occurs mostly on the interconnectors. As can be seen from the decreases in the surplus found for the scenarios in Table 2, although the minimal costs of congestion that result from transmission constraints are (1000 Euros/hour) higher for scenario B, under these wind conditions the difference

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[38] Also investigated with the model, but not included here were scenarios related to a French nuclear power failure and a higher CO_2 price leading to Dutch power exports to Germany.
[39] In the Netherlands, the Ministry of Economic Affairs is responsible for renewable energy policy
[40] Although with strongly aggregated nodes.

between nodal prices and the result of counter trading is still small (less than 1000 Euros / hour, the figures are rounded off to the nearest thousand in the table).

Table 1 increase in social costs of managing congestion, per method

Scenario	**Optimal dispatch** (€/ hour)	**Counter Trade** (€/ hour)
Base case	6000	6000
Scenario B	7000	7000

This does not mean there would not be any differences in the dispatch. As can be seen in Table 2, nodal pricing would create lower prices in areas which export power and higher prices in nodes that are further away. These differences become more pronounced as the amount of wind increases.

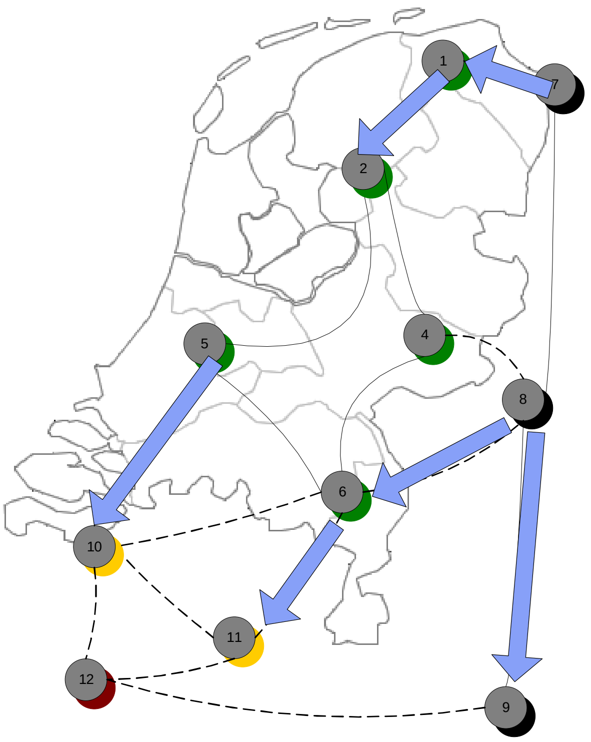

Figure 3: Flows exceeding transmission capacity given unconstrained dispatch for base case

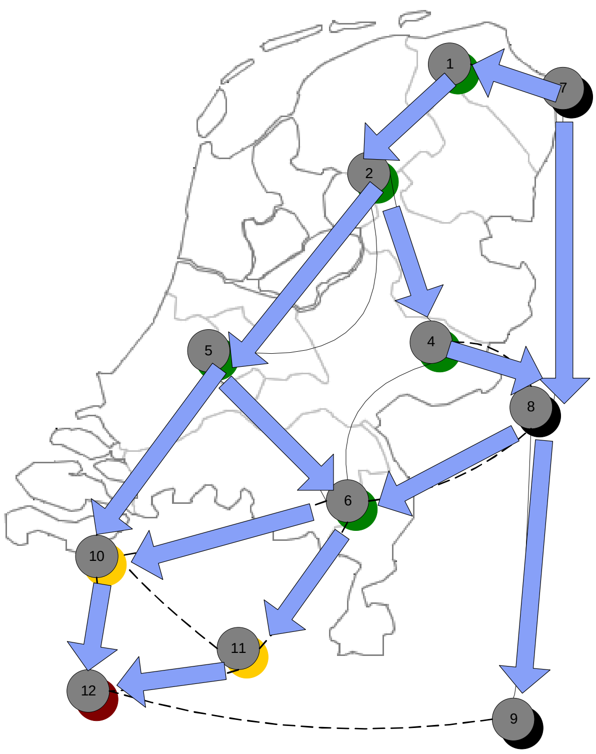

Figure 4: lows exceeding transmission capacity given unconstrained dispatch for scenario b

Table 2 Prices per node, given nodal or national price zones

Node	1	2	4	5	6	7	8	9	10	11	12
Base case nodal price (€/MWh)	41,2	42	42,1	40,8	42,6	36,7	41,8	42,8	44,7	43,6	43,5
Base case national price (€/MWh)	41,3	41,3	41,3	41,3	41,3	41,6	41,6	41,6	44,2	44,2	43,5
Scenario B nodal price (€/MWh)	39,7	41,6	41,7	40,3	42,4	36,7	41,7	42,8	44,8	43,6	43,5
Scenario B national price (€/MWh)	40,8	40,8	40,8	40,8	40,8	41,5	41,5	41,5	44,2	44,2	43,5

Next, we assume that high wind conditions occur in scenario B. This increases the congestion costs to around 70.000 euros, as is illustrated in the graph below.

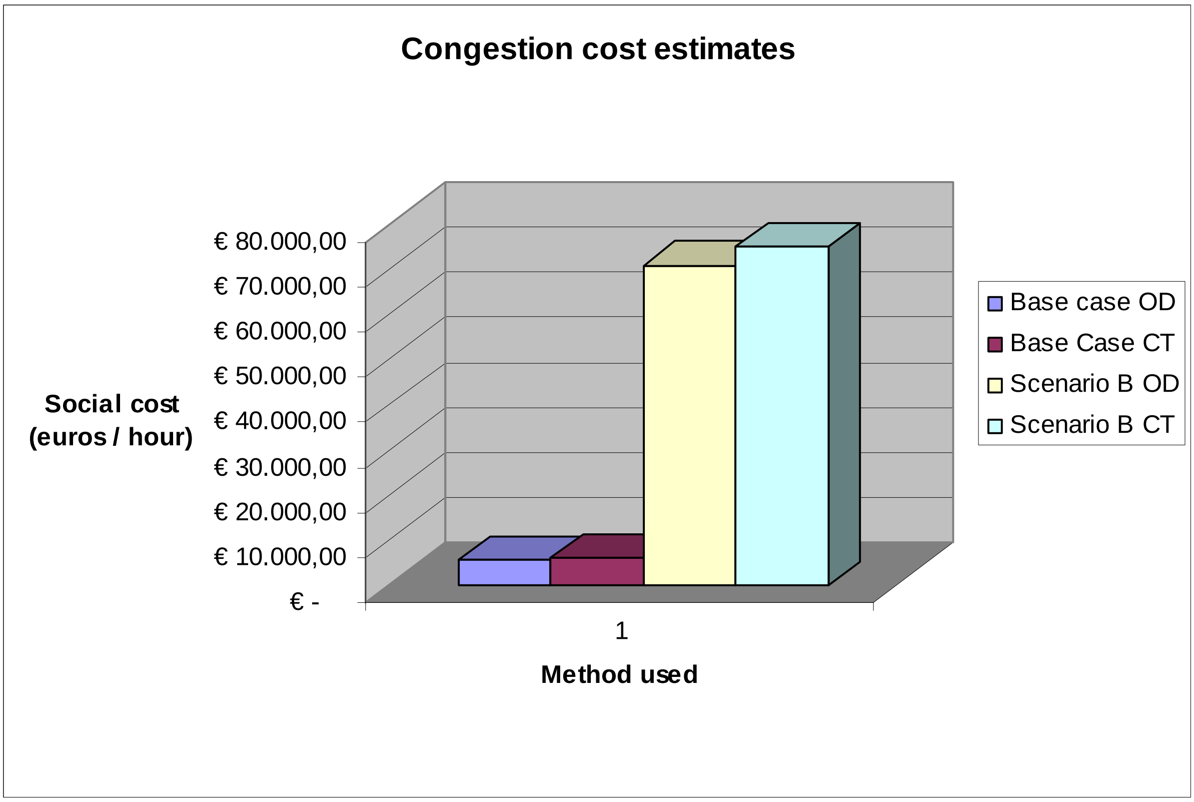

Figure 5: Congestion cost estimates for reference scenario at 25% wind output and scenario b at 100% wind output

Next, we assume higher levels (50%, 75% and 100% rated capacity) of wind power coincide with peak demand. This translates into far greater flows of power if dispatch is unconstrained (see Figure 4). That implies greater social costs from congestion, and will increase the differences in between more efficient pricing and national prices, as can be seen in Table 4.

Table 3: Social costs of congestion per method for high wind conditions

Congestion management method (social costs of congestion)	**Base case optimal dispatch** (€/ hour)	**Base case counter trade** (€/ hour)	**Scenario b optimal dispatch** (€/ hour)	**Scenario b counter trade** (€/ hour)
Wind power availability 50%	19000	21000	22000	23000
Wind power availability 75%	38000	40000	53000	56000
Wind power availability 100%	61000	64000	71000	74000

Maintaining national prices increases congestion and is estimated to cost around 3000 Euros per hour in both cases for the highest amount of wind. Although the base case features less wind capacity in the north of the Netherlands, there is still significant wind in the north of Germany to transport. It also lacks more such capacity in the west to balance supply.

In order to translate these results into a yearly estimate we need to know how many hours per year the relevant conditions occur during peak load conditions. The amount of hours can then be estimated roughly using the formula defined in equation 6.

# of hours in which congestion occurs = # of hours in a year * % high wind hours* % peak load demand hours (6)

Wind speed varies both seasonally and from year to year. Data from the Dutch office of statistics (CBS, 2009) give a monthly index (called the Windex) which indicates whether production was high or low compared to yearly averages. This index is strongly correlated with the number of hours during which the production of the existing wind turbines is at maximum rated capacity (Segers, 2009a personal communication).

In order to find a rough estimate of the amount of hours during which the highest wind production took place in a year, the number of months in which the windex indicator was over 100 were therefore found for the last three years. This percentage of the hours in a full year was then multiplied by a percentage of 25% to find a rough estimate of the number of hours during which both peak load and peak wind conditions may occur. This allows for a rough estimate of the relevant number of hours to be in the range of 500 to 1000 hours per year, using data calculated by Segers (2009b) for the last three years (see table 3) .

Table 3: Overview of calculation of hours during which congestion due to wind may take place

Year	**months with windex > 100**	**total hours**	**% peak demand assumed**	**Scenario B hours**
2005	3	8760	25	547,5
2006	6			1095
2007	3			547,5

The level of congestion costs in a year can then be roughly estimated by multiplying the amount of hours in which congestion take place by the level of congestion costs reported in chapter 4 of this thesis, as shown in equation (7A14.2).

Yearly congestion costs = congestion cost estimate * (# of hours in which congestion occurs) **(7)**

The resulting cost estimates (see Table 4) suggest that the deployed wind power leads to yearly congestion costs of around 41 million Euros for scenario B in conditions comparable to 2005 or 2007. For wind conditions in a year such as 2006, the costs are estimated to be double this figure: up to 82 million euros for scenario B.

Table 4: Yearly congestion cost estimates for scenario B and base case

High wind and peak demand hours	**Yearly congestion costs (scenario B)**	**Yearly congestion costs (reference scenario)**
547,5	€ 41.001.180	€ 33.397.500
1095	€ 82.002.360	€ 66.795.000
547,5	€ 41.001.180	€ 33.397.500

Finally, we look at different zonal price configurations for scenario B under heavy wind conditions, and examine whether these approach nodal pricing solutions. As noted in section 2, research by Bjørndal and Jornsten (2008) suggested using such price zones would allow social costs of congestion to be reduced to a level close to that achievable using nodal prices. In order to find out if this is the case for the Netherlands and Germany, the different zonal boundaries are shown graphically were investigated using the model. (see Figure 6)

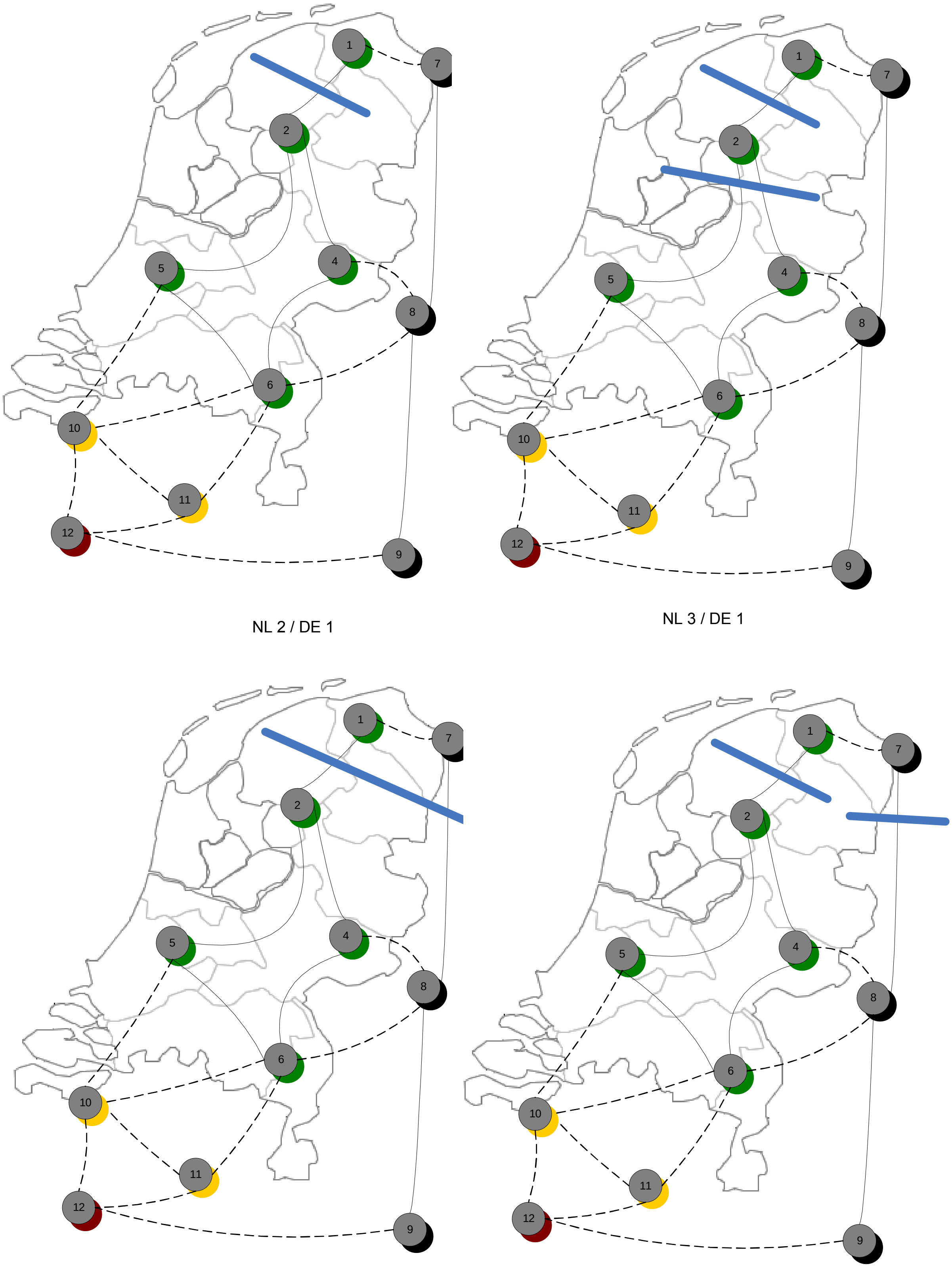

Figure 6: Possible price zone configurations for managing congestion identified in scenario b

The results of running the model for scenario B, given these zonal configurations, are shown in the table below, while the unconstrained dispatch, optimal dispatch and single national price zones (assuming counter trade) are reproduced in the first three columns as a reference. Figures are rounded off to the nearest thousand.

Table 3: social costs of congestion for scenario B with 100% wind power availability

Congestion management method (social costs of congestion)	**Optimal dispatch** (€/ hour)	**Counter trade** (€/ hour)	**Nl2 / De 1**	**Nl3 / De 1**	**Nl 2 / De 2**	**Nl 1 / De 2**	**Nl/De/Nor**
Wind power availability 100% of rated power	71000	74000	74000	74000	72000	72000	72000

It is clear that congestion under windy conditions is greater within both the Netherlands and Germany, but that the improvement can be gained mainly within Germany rather than the Dutch network. As could be predicted based on the work of Bjørndal and Jornsten, this model predicts that the greater differences between the costs of production and the quantity of capacity in the north and the rest of Germany would be reflected in stronger price differences when congestion is managed using methods such as zonal or nodal pricing (see Table 3). The zonal configurations that impose a price zone in the north of Germany allow around 2/3 of the social congestion costs to be avoided, while removing the need for counter trading.

6 – Discussion and conclusions

Congestion is increasingly relevant within networks which previously operated based on the copper plate assumption and clearing using a single marginal price, such as the Netherlands. Congestion could be caused by both structural factors (e.g. new capacity in the North of the Netherlands) and incidental conditions (coincidence of peak demand and windy conditions). Under more optimistic assumptions, counter trade does not represent a large additional cost compared to more specific market-based congestion management. As the level of congestion increases however, the model suggests that justifying counter trading becomes more difficult as congestion costs rise.

Speeding up wind power deployment in the north of the Netherlands and in the north of Germany could lead to this phenomenon occurring within the CWE region. If that happens, the model used in this article suggests that zonal prices could come close to delivering the results of nodal prices, if applied within Germany, while continuing to rely on counter trade would imply greater social costs.

Of course this model represents at best a rough approximation of the network, based on limited public data and assumptions concerning an uncertain future. Although the location of congestion found is consistent with expectations such as those mentioned in (Tennet a, 2008) and (Ecofys, 2009), its scope will depend on the development of electricity capacity and more incidental demand and wind conditions. Nevertheless, it may be concluded that congestion should be considered from a regional perspective, whether the actual constrained links are located within countries or between them.

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Article appendix A: model equations and input

Supply and demand

Tables 4 and 5 give the division of demand over the nodes and the estimated costs of production. Full model and data can be found at (*website*)

Node	Share of demand % (2014)	Share of demand MW (2014)
5 (Krimpen)	54	9702
1 (Meeden- Eemshaven)	9	1615
2 (Zwolle)	10	1819
4 (Hengelo)	12	2137
6 (Maasbracht)	14	2507

Cost of production (euro/MWh)	Fuel type
6,6	hydro
10	wind
17,72973	nuclear
38,32	lignite
40,86286	hard coal
42,19448	NGCC
42,19448	NG CHP
58,52842	NG turbine

Table 4: the division of demand over Dutch nodes
Table 5: variable costs per fuel type

Equations related to transmission

The equations below constrain the flows in and out of a node (conforming to Kirchhoff's junction rule, one for each node) and between the nodes in the network (conforming to Kirchhoff's loop rule, one for each independent cycle).

Equations based on Kirchhoff's junction rule:

$$q_i('i_1') = q_{1,7} + q_{1,2} \quad \text{Eq. (A.1)}$$
$$q_i('i_2') = q_{2,5} + q_{2,4} - q_{1,2} \quad \text{Eq. (A.2)}$$
$$q_i('i_4') = q_{4,6} + q_{4,8} - q_{2,4} \quad \text{Eq. (A.3)}$$
$$q_i('i_5') = q_{5,10} + q_{5,6} - q_{2,5} \quad \text{Eq. (A.4)}$$
$$q_i('i_6') = q_{6,9} + q_{6,10} + q_{6,11} - q_{4,6} - q_{5,6} \quad \text{Eq. (A.5)}$$
$$q_i('i_7') = q_{7,8} - q_{1,7} \quad \text{Eq. (A.6)}$$
$$q_i('i_8') = q_{8,9} - q_{7,8} - q_{4,8} \quad \text{Eq. (A.7)}$$
$$q_i('i_9') = - q_{8,9} - q_{6,9} \quad \text{Eq. (A.8)}$$
$$q_i('i_{10}') = q_{10,12} + q_{10,11} - q_{6,10} - q_{5,10} \quad \text{Eq. (A.9)}$$
$$q_i('i_{11}') = q_{11,12} - q_{10,11} - q_{6,11} \quad \text{Eq. (A.10)}$$
$$q_i('i_{12}') = - q_{10,12} - q_{11,12} \quad \text{Eq. (A.11)}$$

Equations based on Kirchhoff's loop rule:

$-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) - X_{5,10}*(q_{5,10}) = 0$ Eq. (A.12)

$X_{10,11}*(q_{10,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$ Eq. (A.13)

$-X_{6,10}*(q_{6,10}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$ Eq. (A.14)

$-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{5,6}*(q_{5,6}) = 0$ Eq. (A.15)

$-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{4,6}*(q_{4,6}) - X_{2,4}*(q_{2,4}) = 0$ Eq. (A.16)

$-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{4,8}*(q_{4,8}) - X_{2,4}*(q_{2,4}) = 0;$ Eq. (A.17)

$X_{6,8}*q_{6,8} + X_{8,9}*q_{8,9} + X_{9,12}*q_{9,12} - X_{11,12}*q_{11,12} - X_{6,11}*q_{6,11} = 0$ Eq. (A.18)

Article appendix b / (Extra data and parameters to be made available on a website)

Available capacity on interconnectors between national networks

For the interconnections between countries, the Net Transfer Capacity (NTC) capacity estimates (Tennet, 2008) can be adopted as an estimate of the cumulative capacity available for day-ahead trade in the market (see table below). Although in practice efforts are taking place which will allow more precise flow based modelling of actual capacity, in practice Available Transfer Capacity (ATC) on connections spanning national borders in the day-ahead market may be even lower due to already allocated capacity[41]. Where the estimates diverge, the lower capacity is given.

Border	NTC 2009 winter (MW)	Includes links
NL-DE	3000	1-7, 4-8, 6-8
NL-BE	2400	5-10, 6-10, 6-11
BE-FR	2200	10-12, 11-12
FR-DE	2750	12-9[42]

Link	Interconnection	Nominal capacity (MW)	Value assumed for model	Reactance used in model (Ohms)
1-7	Meeden – Diele	3290	825	15,32
4-8	Hengelo – Gronau	3290	825	5,64
12-9	France – Germany South		2750	25,4
5-10	Krimpen – Belgium West	1645	800	18,84
6 – 10	Maasbracht – Belgium West	1645	800	21,66
6 - 11	Maasbracht – Belgium East	1645	800	17,48
6-8	Maasbracht-Rommerskirchen/Siersdorf[43]	3420	1350	16,03
10-12	France – Belgium West	unknown	1100	55,4
11-12	France – Belgium East	unknown	1100	45,2

Sources of data listed: (TenneT, 2008), (Hobbs et al, 2004), (ENTSO-E, 2009)

[41] Tennet, the Dutch TSO, was reported to employ a Transmission Reliability Margin (TRM) of at least 300 MW for these connections, according to Haubrich et al. (2001, page 158) based on "*statistical analysis of observed amounts of inadvertent exchange plus a (small) surplus for uncertainty on system conditions beyond the portion already coped with by explicitly considering different scenarios*"

[42] Includes interconnectors not given in model, such as those that go to the RWE control area represented by node 8.

[43] Two circuits in parallel

Annex 1: Validation of model equations and structure

This annex describes the ways in which the base case model, once constructed in GAMS, has been tested in order to validate the way in which it functions. The most important components of the model are the equations governing the way the supply and demand for power in the market is simulated at each node, and the way in which the transport of this power between nodes in the transmission grid is constrained. Simple numerical examples, with parameters chosen for ease of mathematical verification by hand, have been used where possible to test whether the results generated concur with what theory tells us should be the outcome. These results give confidence that the outcomes the model calculates with parameters which are based on data chosen to simulate situations of interest to the research will also be correct.

Validation of supply and demand curves

Supply and demand curves were validated by using a version of the model with equal parameters for supply and demand in each node (see table). This should ensure that no transmission is necessary, and that the resulting price, quantities of production and supply and social welfare resulting in every node should be based on the same equilibrium. Each curve is linear; the parameters A, B and C indicate the maximum quantity demand, the slope of the inverse demand curve and the slop of the cost curve respectively.

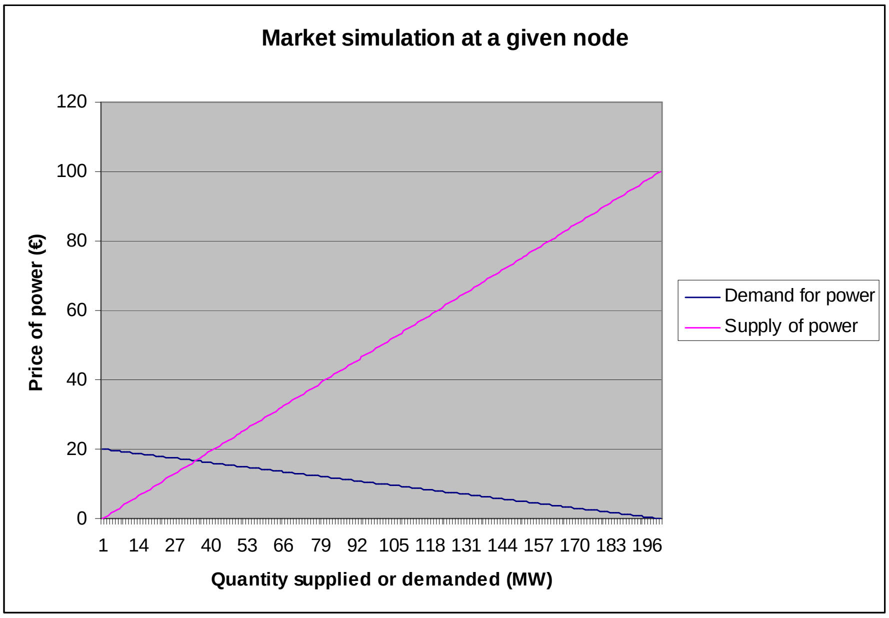


Figure 17: Supply and demand curves used in model validation

This gives us the following equations for the price of supply and demand at a given node 'I' respectively:

Demand(i) : $p_d(i) = a(i) - b(i)*q_d(i)$ **(a1)**

Supply(i) : $p_s(i) = c(i)*q_s(i)$ **(a2)**

The values are given in the table (see Table 16). The resulting supply and demand curves are displayed based on manual calculations.

Table 31 Parameter values used in validation

Node	**a (= "maximum quantity demanded")**	**b (="slope of inverse demand curve")**	**c (= "slope of supply curve, increase in marginal cost of production")**
I1-i11	20	0,1	0,5

The equilibrium point can also be verified mathematically, by deriving the point at which the curves meet:

$$a(i) - b(i)*q_d(i) = c(i)*q_s(i) \qquad (a3)$$

Filling in the correct values for the parameters gives the equation of interest:

$$20-0{,}1*q = 0{,}5*q \qquad (a4)$$

Assuming that the quantities supplied and demanded are equal at the equilibrium point gives us the ability to calculate at which quantity this is:

$$Q_{eq} = 20 \div 0{,}6 = 33{,}333 \text{ Mwh} \qquad (a5)$$

Now substituting this value in either of the equations tells us what the corresponding equilibrium price should be:

$$P_{eq} = 0{,}5 * Q_{eq} = €16{,}17 / \text{Mwh} \qquad (a6)$$

By running the base case model in the GAMS program for the given parameters, we can verify the same correct outcome is found (see Figures 18, 19 and 20).

---- VAR qs quantity produced at node (in megawatt)

	LOWER	LEVEL	UPPER	MARGINAL
i1	.	33.333	+INF	.
i2	.	33.333	+INF	.
i3	.	33.333	+INF	EPS
i4	.	33.333	+INF	.
i5	.	33.333	+INF	.
i6	.	33.333	+INF	.
i7	.	33.333	+INF	.
i8	.	33.333	+INF	.
i9	.	33.333	+INF	.
i10	.	33.333	+INF	.
i11	.	33.333	+INF	.

---- VAR qd quantity demanded at node (in megawatt)

	LOWER	LEVEL	UPPER	MARGINAL
i1	.	33.333	+INF	EPS
i2	.	33.333	+INF	EPS
i3	.	33.333	+INF	.
i4	.	33.333	+INF	EPS
i5	.	33.333	+INF	EPS
i6	.	33.333	+INF	.
i7	.	33.333	+INF	EPS
i8	.	33.333	+INF	EPS

Figure 18 Gams output used in validation 1

---- VAR p price at a node (in dollars)

	LOWER	LEVEL	UPPER	MARGINAL
i1	.	16.667	+INF	.
i2	.	16.667	+INF	.
i3	.	16.667	+INF	.
i4	.	16.667	+INF	.
i5	.	16.667	+INF	.
i6	.	16.667	+INF	.
i7	.	16.667	+INF	.
i8	.	16.667	+INF	.
i9	.	16.667	+INF	.
i10	.	16.667	+INF	.
i11	.	16.667	+INF	.

Figure 19 Gams output used in validation 2

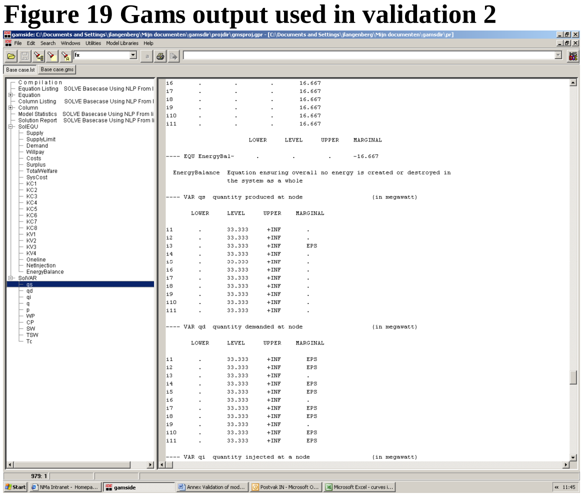


Figure 20 Gams output used in validation 3

Validation of transmission equations and electricity transport

The transport of electricity is governed by the physical laws first derived by Kirchhoff. Two such laws can be applied to networks such as electricity grids: the circuit rule, which applies to the through variables (in this case, nodes in the network) and the loop rule, which applies to the across variables (in this case, the links between nodes).

The method applied to derive these equations for the network used in the base case model is described in Annex 2. The resulting equations are the following, where qi(i) refers to the net amount of electricity injected into or withdrawn from the grid at a given node i:

KC1 : q_i('i1') = $q_{1,7} + q_{1,2}$
KC2 : q_i('i2') = $q_{2,5} + q_{2,4} - q_{1,2}$
KC4 : q_i('i4') = $q_{4,6} + q_{4,8} - q_{2,4}$
KC5 : q_i('i5') = $q_{5,10} + q_{5,6} - q_{2,5}$
KC6 : q_i('i6') = $q_{6,9} + q_{6,10} + q_{6,11} - q_{4,6} - q_{5,6}$
KC7 : q_i('i7') = $q_{7,8} - q_{1,7}$
KC8 : q_i('i8') = $q_{8,9} - q_{7,8} - q_{4,8}$
KC9 : q_i('i9') = $- q_{8,9} - q_{6,9}$
KC10 : q_i('i10') = $q_{10,12} + q_{10,11} - q_{6,10} - q_{5,10}$
KC11 : q_i('i11') = $q_{11,12} - q_{10,11} - q_{6,11}$
KC12 : q_i('i12') = $- q_{10,12} - q_{11,12}$

KV1 : $-q_{25} - q_{12} + q_{17} + q_{78} + q_{89} - q_{69} + q_{611} + q_{1112} - q_{1012} - q_{510} = 0$
KV2 : $q_{1011} + q_{1112} - q_{1012} = 0$
KV3 : $-q_{610} + q_{611} + q_{1112} - q_{1012} = 0$
KV4 : $-q_{25} - q_{12} + q_{17} + q_{78} + q_{89} - q_{69} - q_{56} = 0$;
KV5 : $-q_{12} + q_{17} + q_{78} + q_{89} - q_{69} - q_{46} - q_{24} = 0$
KV6 : $-q_{12} + q_{17} + q_{78} - q_{48} - q_{24} = 0$

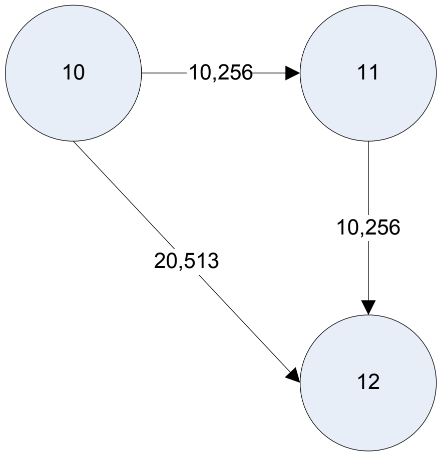
A simple example explaining the behaviour of flows in the network using one equation

The way the equations function can best be demonstrated transparently by using a simple example which singles out part of the model. For this, we examine the bottom part of the network, focusing on the nodes 10,11 and 12 and the corresponding equations. Adjusting the model to take into account only production in node 10 and 12 and the links between 10, 11 and 12 can be achieved by setting production parameters and constraints as indicated in the table (see Table 32) , and only considering the relevant equation KV2. The maximum capacity of the transmission links is set to equal 100, so flows should be constrained only by laws governing their physical behaviour and not by capacity limits.

Table 32: parameters used for flow equation validation

Node	**a** **(= “maximum quantity demanded”)**	**b** **(=”slope of inverse demand curve”)**	**c** **(= “slope of the supply curve, increase in marginal cost of production”)**
10	20	0,1	0,5
11	0	0	N/A
I12	20	0,1	1,0

Similarly to the previous example, we know what the optimal supply of electricity will be: two thirds of production should come from the node (10) with a cost function which is half as steep as the other (12).



Flows in validation example

The flows are divided. Two thirds of the electricity flows along the direct route, whereas the other third takes the indirect route passing across node 11. This corresponds to the division which we would expect, given the equation KV2:

Kv2: $\mathbf{q_{10,11} + q_{11,12} - q_{10,12} = 0}$
10,256+10,256-20,513 = 0

Intuitively, it also possible to understand why this happens. Electricity flows depend on the resistance offered by the lines. In the example, the resistance of each link is assumed to be equal. The path across node 11 therefore represents twice the resistance of the direct route from 10 to 12. The equation therefore ensures that the direct flow from 10 to 12 transports 2/3 of the power and that the flow from 10 to 11 to 12 carries 1/3 of the power.

Extending the example to cover 4 nodes and 5 lines

To further demonstrate the behaviour of flows according to the equations, the example above is extended by considering node 6 in addition to 10,11 and 12. Again considering simplified transport from node 10 to 12, the parameters given in the table below are used. In addition to the equation Kv2, Kv3 is also necessary as an additional cycle has become possible[44].

[44] The number of equations necessary is equal to m-n+1, in this case 5-4+1=2. See also Annex 2.

Table 33: parameters used for extension of flow equation validation

Node	**a** (= "maximum quantity demanded")	**b** (="slope of inverse demand curve")	**c** (= "slope of the supply curve, increase in marginal cost of production")
10	20	0,1	0,5
11	0	0	N/A
6	0	0	N/A
I12	20	0,1	1,0

Supply is the same as in the previous example. However, transport has now changed: a new route is possible via nodes 6 and 11. The division over the routes is now somewhat less intuitive than previously: the resistance to flows through nodes 6 and 11 is three times that for flows from 10 to 12. The resistance over the path from 10 to 11 to 12 is twice that directly from 10 to 12. 1/8 of the power therefore flows over the longer route to 11 through 6, 2/8 between 10 and 11 and these combine to give 3/8 of the power from 11 to 12. The remaining 5/8 flows directly. Again, for clarity, the values are given within the equations below:

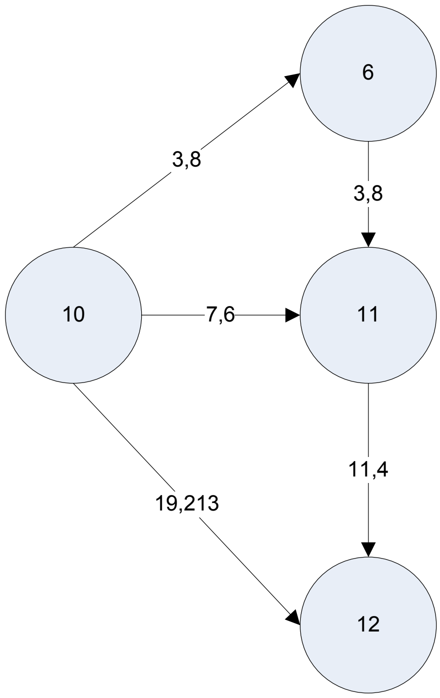
KV3 : $-q_{6,10} + q_{6,11} + q_{11,12} - q_{10,12} = 0$

$$-(-3,846) + 3,846 + 11,538 - 19,231 = 0 \quad \text{(a7)}$$

Kv2: $q_{10,11} + q_{11,12} - q_{10,12} = 0$

$$7,692 + 11,538 - 19,231 = 0 \quad \text{(a8)}$$

The flow over 10-6-11 is 3,846, which equals 1/8 of 30,769 (the total amount transported). The flow from 10-11 is twice this, while that from 11 – 12 equals the sum of those two flows, and the flow from 10-12 directly is equal to 5/8 of 30,769.



Flows in second validation example

Behaviour of the combined network representation

Finally, overall network behaviour with all the equations can be seen by again considering a simplified example. In this case, the parameters for the supply curves have been chosen so that the increase in the price for supplying power is twice as quick when production increases in France compared to the other nodes. The values of the parameters are given in the table below:

Table 34: parameters used for network flow behaviour validation

Node	**a (= "maximum quantity demanded")**	**b (="slope of inverse demand curve")**	**c (= "slope of supply curve, increase in marginal cost of production")**
i1-i11	20	0,1	0,5
i12	20	0,1	1,0

The result of doing so, given no constraints on transmission capacity is that production should increase in all the other nodes in order to export to meet the supply of electricity in France, the other half being supplied by the cheapest half of producers within node 12. The output of the model is displayed the production given in the table.
The resulting price is equal in all nodes, as there is sufficient transmission capacity to trade power in order to allow the same equilibrium to be reached in each node (and as the demand curves in all nodes have the same slope). The equilibrium price is € 16,794 per MW, the quantity consumed in each exporting node is 32,061, while the quantity produced rises to 33,588.

We can see that in comparison with the first example, which was used to illustrate the functioning of the supply curves, trade here allows French consumers to benefit from the much cheaper Dutch and German supply of power, increasing their surplus. At the same time trade increases prices and depresses consumption slightly at all Dutch, Belgian and German nodes. Dutch and German producers will benefit from slightly higher prices, increasing their share of the surplus. The more expensive half of French electricity producers will lose market share to imports. The surplus is 3526,718 Euros.

Table 35: Model output for network flow behaviour validation

Number of node	Level of production	Level of consumption	Net export	Surplus
1	**33,588**	**32,061**	**1,527**	**307,791**
2	**33,588**	**32,061**	**1,527**	**307,791**
4	**33,588**	**32,061**	**1,527**	**307,791**
5	**33,588**	**32,061**	**1,527**	**307,791**
6	**33,588**	**32,061**	**1,527**	**307,791**
7	**33,588**	**32,061**	**1,527**	**307,791**
8	**33,588**	**32,061**	**1,527**	**307,791**
9	**33,588**	**32,061**	**1,527**	**307,791**
10	**33,588**	**32,061**	**1,527**	**307,791**
11	**33,588**	**32,061**	**1,527**	**307,791**
12	**16,794**	**32,061**	**15,27**	**448.808**

This situation is represented graphically in the curve for an exporting node. The suppliers can sell additional capacity in their export market. This ensures the price increases at the node. The green area shows the increased surplus from exports for the suppliers.

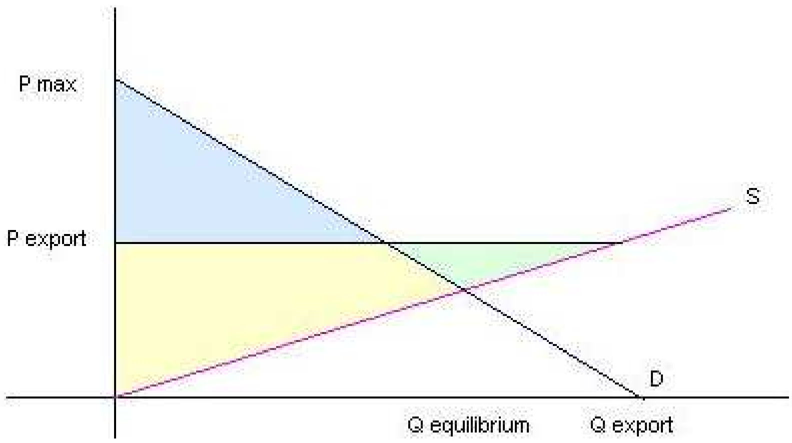


Figure 18: Curves in an exporting node

Annex 2 Derivation of equations based on Kirchhoff's laws

The base case model constructed for the quantitative part of this research consists of a set of equations and parameters which can be solved using solvers in the GAMS program. The most important components of the model are the equations governing the way the supply and demand for power in the market is simulated at each node, and the way in which the transport of this power between nodes in the transmission grid is constrained. This annex explains how some of the equations, governing the way the transmission of electricity may take place through the network, were derived.

Kirchhoff's laws can be interpreted as a set of rules which constrain the ways in which electricity may flow through a given network. By representing the components of the network as ideal components, circuit theory and these rules can be combined to derive the minimum resulting independent equations.

The network model is shown in Figure 19: the version to the left is the one presented in chapter 3, the more stylized form to the right shall be used in the rest of this annex. The two are equivalent from the perspective of network theory.[45]

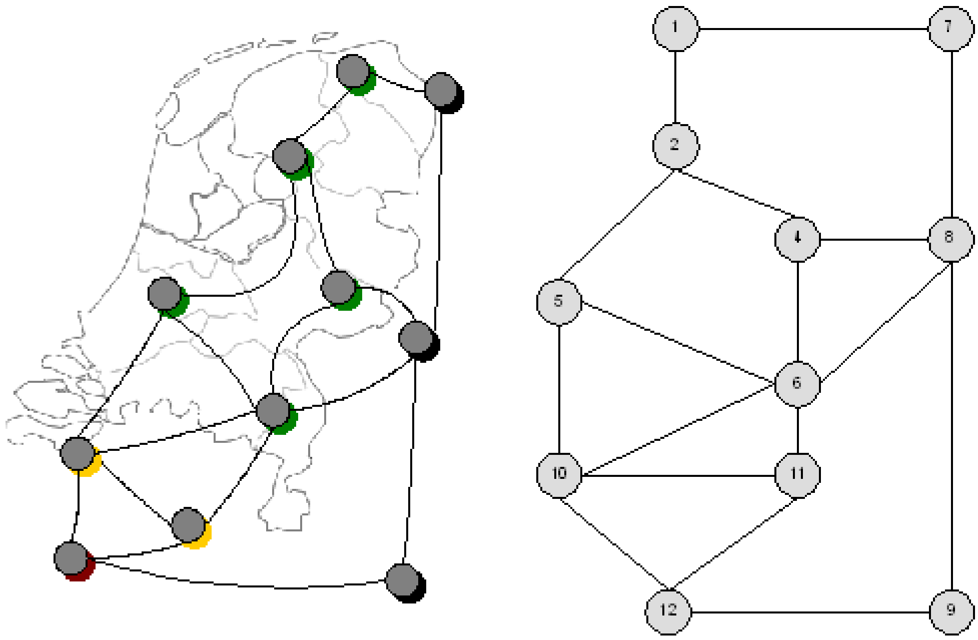


Figure 19: scope of network model

Derivation of equations following from Kirchhoff's current law (junction rule)

For each node in the network, from Kirchhoff's current law or junction rule it follows that the sum of the flows entering and leaving the node must sum to the equivalent value of the total injection that takes place.

[45] Note that due to changes in the model scope during development, there is no node with the number 3 in the model.

As an example, we discuss node 1. Node 1 is connected to nodes 7 and 2. The net amount injected into or withdrawn from the grid at node 1, must therefore equal those flows entering or leaving the node through the links to nodes 7 and 2. This is achieved in the model by constraining the allowable values which the quantity injected or withdrawn at node 1 can take in the following way:

$\mathbf{q_i(i1) = q_{1,7} + q_{1,2}}$ **(a9)**

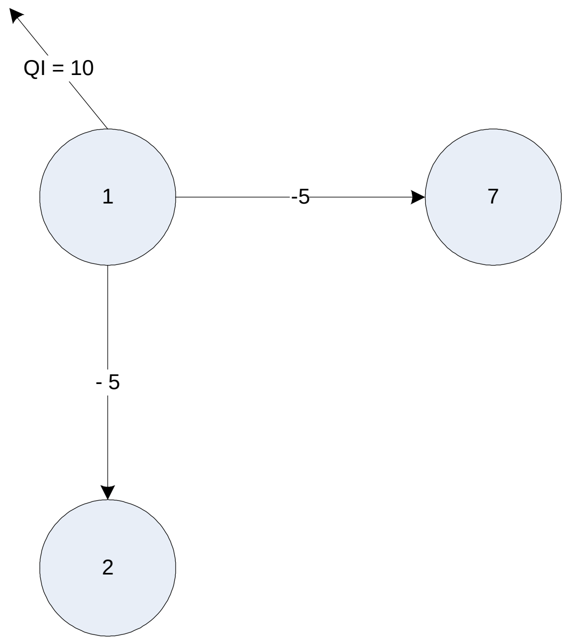


Figure 20: simple example illustrating equations balancing flows through a node

When the values of these three values are positive, the left hand term represents a net injection, and the other two terms represent flows from node 1 to nodes 7 and 2. When one of the two right hand terms is negative, then the direction of flow is reversed, i.e. electricity is transported from either node 7 or 2 to node 1. So, in the hypothetical example displayed in the picture, if the flows going out to the two connected nodes are -5 each, that means 10 units of electricity must be injected at node 1. This means node 1 is a net importer of electricity.

This logic is applied to derive similar equations for each node in the network in the base case model. The resulting set of equations is listed below, where qi(i) refers to the net amount of electricity injected into or withdrawn from the grid at a given node I, and q(i,j) represents a positive flow from node ‘i’ to node ‘j’[46]:

KC1 : $\mathbf{q_i(i1) = q_{1,7} + q_{1,2}}$
KC2 : $\mathbf{q_i(i2) = q_{2,5} + q_{2,4} - q_{1,2}}$
KC4 : $\mathbf{q_i(i4) = q_{4,6} + q_{4,8} - q_{2,4}}$
KC5 : $\mathbf{q_i(i5) = q_{510} + q_{56} - q_{25}}$
KC6 : $\mathbf{q_i(i6) = q_{69} + q_{610} + q_{611} - q_{46} - q_{56}}$

[46] Once again, a negative flow from node i to j represents a flow in the opposite direction.

KC7 : $q_i(i7) = q_{78} - q_{17}$
KC8 : $q_i(i8) = q_{89} - q_{78} - q_{48}$
KC9 : $q_i(i9) = - q_{89} - q_{69}$
KC10 : $q_i(i10) = q_{1012} + q_{1011} - q_{610} - q_{510}$
KC11 : $q_i(i11) = q_{1112} - q_{1011} - q_{611}$
KC12 : $q_i(i12) = - q_{1012} - q_{1112}$

Derivation of equations following from Kirchhoff's voltage law (loop rule, principle of least resistance)

Kirchhoff's voltage law states that the algebraic sum of the potential differences across all the components around any circuit (cycle) in an electrical network is zero. An equation could therefore be found for every possible cycle within the network modelled. However, this is not necessary: a minimal number of equations can be found by determining a set of fundamental cycles, which can be translated into a set of linearly independent equations constraining flows through the network. The method followed here is based on that described in (Dolan and Aldous, 1993)[47]. The law is also known as the 'principle of least resistance', as the consequence of such equations is to guide the flow of electricity along the path which represents the lowest resistance route (between net injection and withdrawal) (Smeers, 2008).

First, links are removed from the network representation until a spanning tree is found (i.e. a sub-graph of the network containing no cycles). See Figure 21.

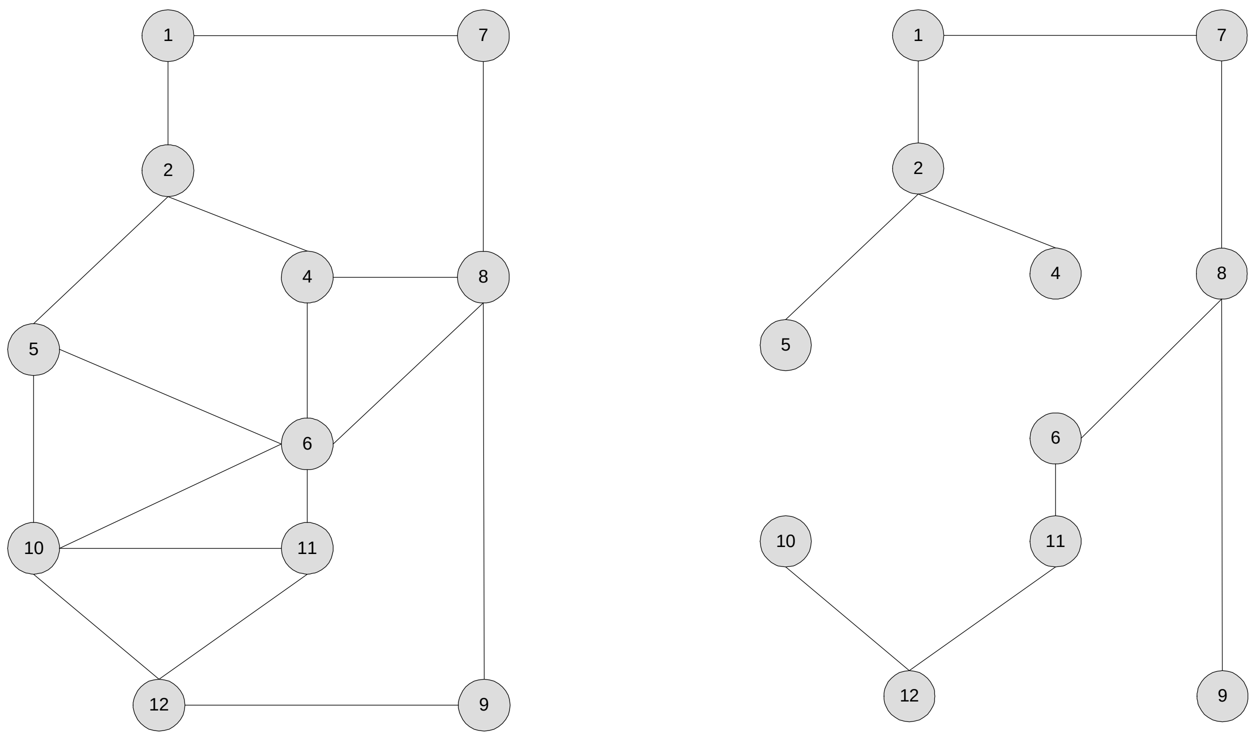


Figure 21: network model and spanning tree derived from it

[47] This is itself reported by the authors to be similar to that first given by Kirchhoff himself, in 1847, if formulated slightly differently.

Note that directions need to be given to each link in order to determine the equations. The chosen direction is arbitrary - it doesn't make a difference for the result as long as the notation is consistent over all the variables used and equations that are defined.

Next, for each of the chords (i.e. the links which have been removed), the link is added and the corresponding resulting cycle is translated into an equation. By travelling along the cycle, adding the potential difference resulting from the quantity transported between the nodes, and constraining the sum of these to equal zero, an equation results.

An example is shown using Figure 22. This cycle gives the first equation shown at the end of this page.

The number of such independent equations in a network of n vertices and m links can be shown to equal m-1+1, where 'm' represents the number of links and 'n' the number of vertices or nodes in the network (Dolan and Aldous, 1993). In this case therefore, (17-11+1) = 7 equations are necessary. These are given below:

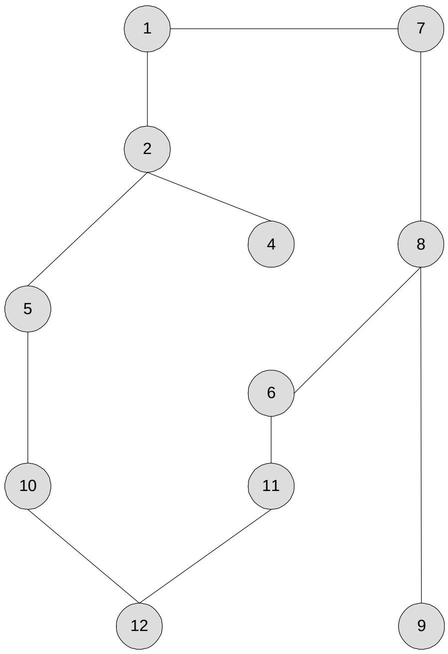


Figure 22: one of the cycles found using the spanning tree

In each case, the notation q*ij* represents a flow from node 'i' to node 'j' if positive and from 'j' to 'i' when the sign is negative. The 'direction' given to the links mentioned earlier is thus from 'i' to 'j'.

KV1: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) - X_{5,10}*(q_{5,10}) = 0$

KV2: $X_{10,11}*(q_{10,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV3: $-X_{6,10}*(q_{6,10}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV4: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{5,6}*(q_{5,6}) = 0$

KV4: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{4,6}*(q_{4,6}) - X_{2,4}*(q_{2,4}) = 0$

KV5: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{4,8}*(q_{4,8}) - X_{2,4}*(q_{2,4}) = 0;$

KV6: $X_{6,8}*q_{6,8} + X_{8,9}*q_{8,9} + X_{9,12}*q_{9,12} - X_{11,12}*q_{11,12} - X_{6,11}*q_{6,11} = 0$

The other six cycles are displayed graphically in figures 23-28.

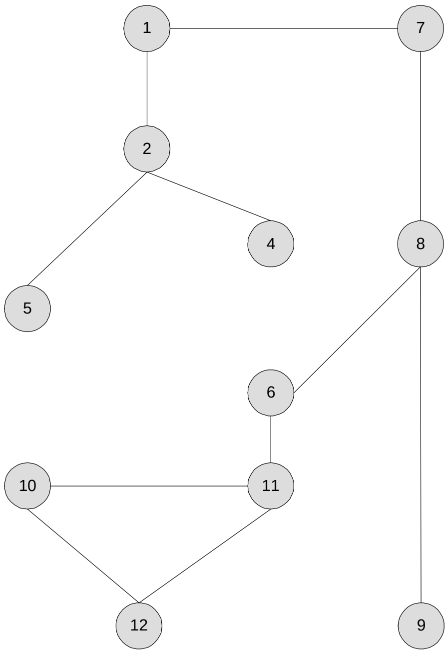


Figure 23: one of the cycles found using the spanning tree

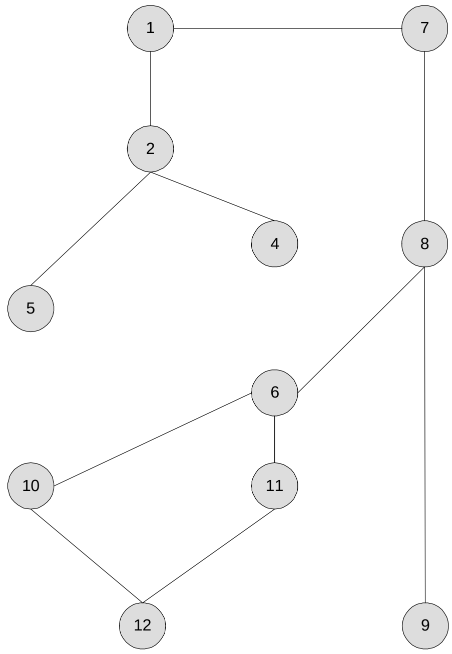


Figure 24: one of the cycles found using the spanning tree

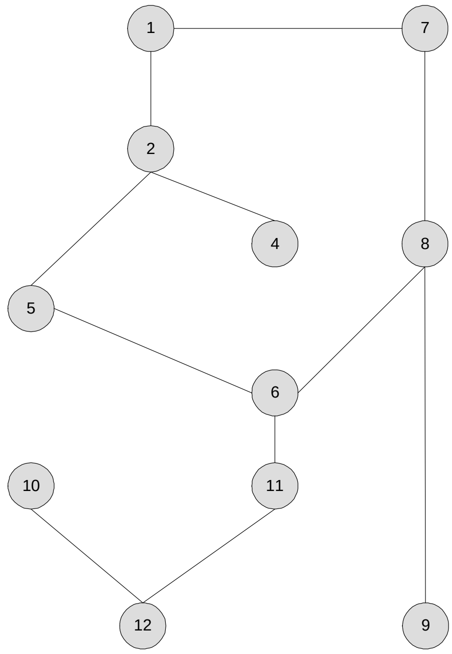


Figure 25: one of the cycles found using the spanning tree

From top left clockwise, the cycles are related to equations KV 2,3,4,5, 6 and 7.

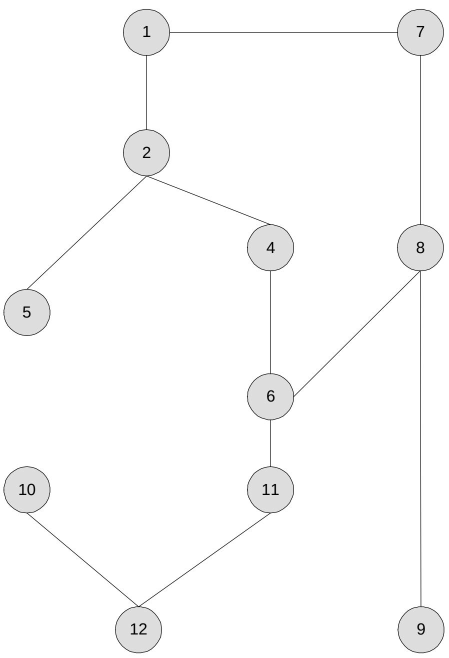


Figure 26: one of the cycles found using the spanning tree

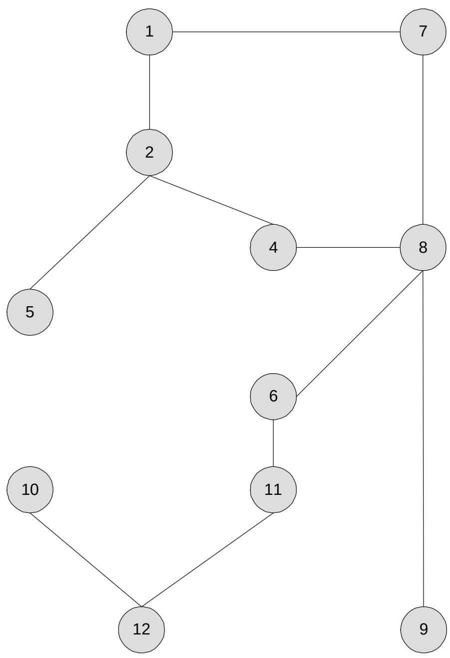


Figure 27: one of the cycles found using the spanning tree

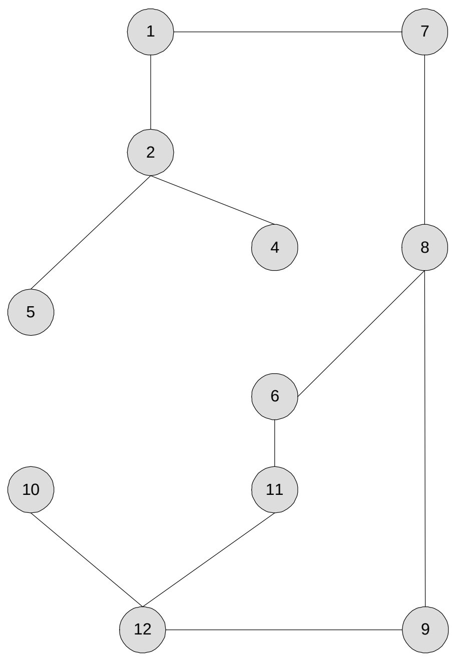


Figure 28: one of the cycles found using the spanning tree

Adding the effects of reactance to the equations governing flows

The equations derived in the first part of this annex would be accurate in describing the flows through the network only if we were to assume that the resistance of all the transmission lines were equal. In practice, electricity flows are governed by the proportional differences that exist between these resistances. This is represented in the model by multiplying the variable representing flows through each of the lines with the reactance of that line, in accordance with Ohm's law[48] to give the equations used in the model itself. The sources of data and parameter estimation of the reactance of the various lines are described elsewhere in this thesis. (See Annex 6).

KV1: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) - X_{5,10}*(q_{5,10}) = 0$

KV2: $X_{10,11}*(q_{10,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV3: $-X_{6,10}*(q_{6,10}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV4: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{5,6}*(q_{5,6}) = 0$

KV4: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{4,6}*(q_{4,6}) - X_{2,4}*(q_{2,4}) = 0$

KV5: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{4,8}*(q_{4,8}) - X_{2,4}*(q_{2,4}) = 0;$

KV6: $X_{6,8}*q_{6,8} + X_{8,9}*q_{8,9} + X_{9,12}*q_{9,12} - X_{11,12}*q_{11,12} - X_{6,11}*q_{6,11} = 0$

[48] Although in reality Ohm's law applies to both the real and imaginary components of current within AC networks which together form the impedance, in a model that is based on the 'DC' load-flow approximation, the resistance is assumed to be negligible compared to the reactance of each the links. This means that the value for the reactance of a component can be used in the place of the impedance.

Annex 3: Potential bottlenecks in the Dutch 380kv transmission grid between 2008-2014

This annex displays two figures from Tennet's (the Dutch TSO) quality and capacity plans for the period between 2008 and 2014. Calculations are based on load-flows and scenarios which represent potential relevant trends in demand and investment. 'Excursions' for each scenario test the robustness in situations where generation at either the Maasvlakte or Eemshaven coastal locations increases strongly.

These figures suggest congestion can occur both north-south (e.g. to the north of Zwolle) and from the west to the east (e.g. between Krimpen and Geertruidenberg, or Zwolle and the German border).

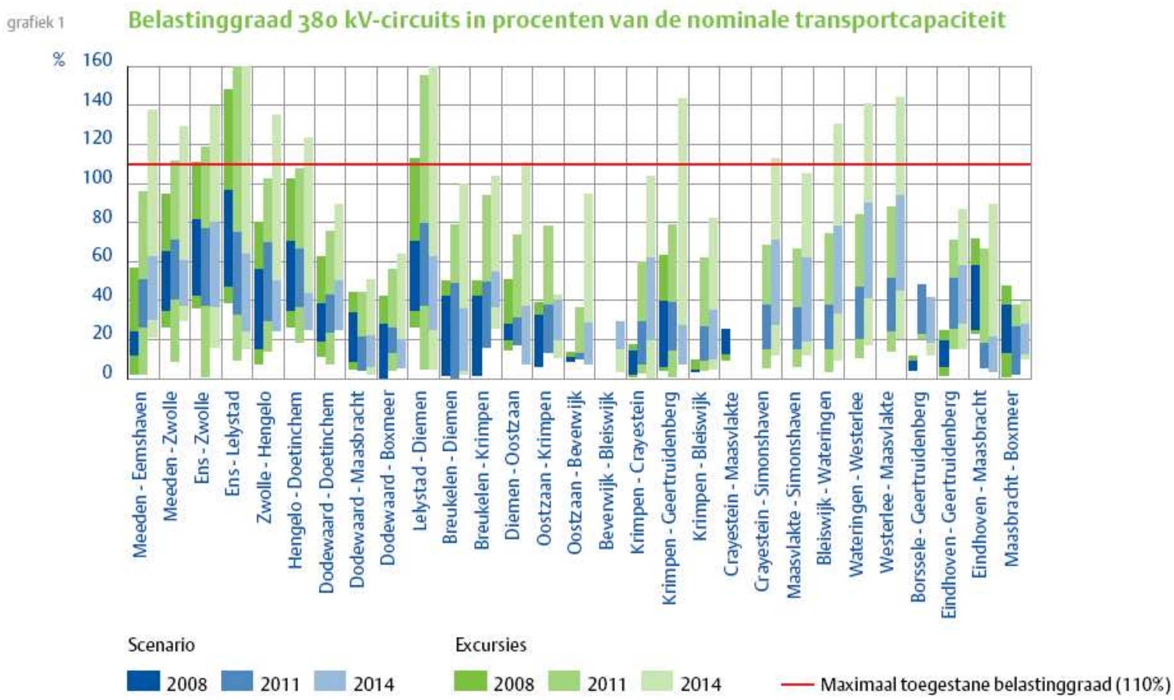


Figure 30: Reference scenario 'Groene revolutie' – 2 % growth in demand and realization of plans assumed Source: (Tennet 2008)

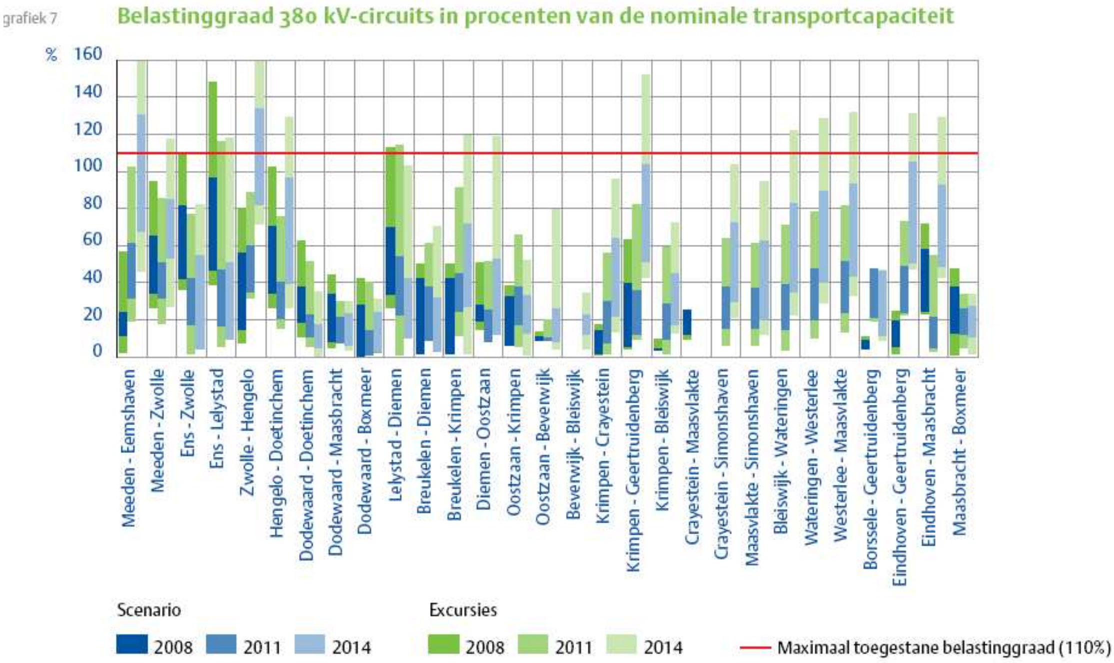


Figure 31: Reference scenario Nieuwe Burchten (represents assumptions related to high export)
Source: (Tennet 2008)

Annex 4: Estimation of supply curve parameters

This annex describes the process through which the supply curves were estimated, including the sources of the data used. In general, the approach described by Sharma (2007) and later reported in De Jong (2009) is followed. This implies the starting point for the analysis is a bottom-up calculation of the marginal costs of operating a power plant, depending on the energy technology employed. The division of these plants over the nodes in the network is then used to construct curves based on marginal costs of available capacity at each point, using a linear regression method.

In order to translate this basic input into usable information for the model, two major assumptions are made. The first is that the suppliers of electricity will bid to sell their electricity production based on these marginal costs, rather than attempting to recover additional (e.g. capital cost) revenues.
It is important to remember that all accepted bids within the spot market for electricity are paid the marginal bid price, that is they receive the same amount as the highest accepted bid, regardless of whether their own bid price was lower. This would allow many of the bidders to recoup some or all of their fixed costs most of the time, even when bidding based on marginal cost. This assumption can therefore be understood as representing rational bidding behaviour under a perfectly competitive market situation. A further discussion can be found in chapter 3.

The second assumption is that the aggregation of these data to linear curves through a regression results in a fair representation of those bidding curves which could be reasonably expected to occur in reality. As discussed in chapter 3, using a linear curve in place of a step-function entails the loss of some accuracy compared to what is the case in reality. However, it is mathematically significantly simpler to model. At this stage modelling these curves in a more accurate way goes beyond the scope of the time of this research.
Chapter 3 discusses the reality of bidding curves and the way they have been modelled in the academic literature in more detail.

This annex describes the process used to arrive at parameters for use in the model in three steps. The first deals with the estimation of marginal costs. The following step involves estimating the division of plants with these costs over the locations in the network. The final step is the translation of this data to usable parameters, using a simple regression analysis.

1) Estimation of marginal costs experienced by suppliers of electricity

For the purpose of modelling the behaviour of electricity suppliers, it is assumed here that these actors bid to sell their electricity on the basis of their marginal costs. What are the relevant components of these costs? For the purposes of this study, these are limited to three factors: fuel costs, operational costs and costs associated with emission prices. Each of these is briefly discussed.

Fuel costs

All generation of electricity using fossil energy technology implies costs for buying fuel. The amount to be paid per megawatt generated depends on both the raw price of the fuel quantity needed that contains the necessary energy, and on the efficiency of the plant in question, as is defined in equation a.4.1.

Fuel cost (€/MWh) = Fuel quantity (calorific value 1 MW, e.g. tons of coal, m^3 of gas) * net plant efficiency (a.4.1)

For this research, it is assumed that of these factors, estimates of developments fuel prices could have significantly changed from the estimates used by Sharma (2007) while plant efficiency is not likely to have changed significantly per energy technology, given the long lifespan of such installations. Therefore, following the more recent research performed by Ummels(2009), the values for fuel prices are based on those values reported in from the World Energy Outlook 2008 as expected prices for 2015. Combining these with the efficiency estimates gives the cost reported in table 21.

Table 36: Fuel costs per technology

Energy technology	**Fuel price € / GJ**	**Net efficiency**	**Fuel cost € / MWh**
Hydropower	0	100%	€0
Wind power	0	100%	€0
Hard coal condensation	2	37%	€17,14
Lignite condensation	1,36	42%	€12,24
CHP natural gas	5	58%	€31
Natural gas combined cycle	5	58%	€31
Natural gas turbine	5	38%	€47
Oil	10,5	41%	€92,2
CHP biomass (pellets)			€14,59[49]
CHP biomass (straw)			€14,59
Uranium	1	37%	€9,7

Operational and management costs

Operational costs include non fuel expenses directly related to running the plant which are variable rather than fixed, such as staff and maintenance.
For these estimates are based on values given in the available academic literature, as used by Sharma (2007). The underlying assumption here is again that these costs are less volatile than fuel costs, so that these values can still form a good indicator of expected practice. They are displayed in the table below.

[49] The value for CHP fuel costs used by Sharma is taken directly rather than calculated, from Wiese et al (2007)

Table 37: Operation and maintenance costs per technology

Energy technology	typical capacity factor	O/M costs (€/MWh)
Hydro power	51%	€6,6
Wind power	25%	€10
Hard coal condensation	91%	€8
Lignite condensation	91%	€7,5
CHP natural gas	91%	€8,15
Natural gas combined cycle / turbine	91%	€4
Oil	85%	€4
CHP biomass	91%	€10,7
Nuclear	91%	€8

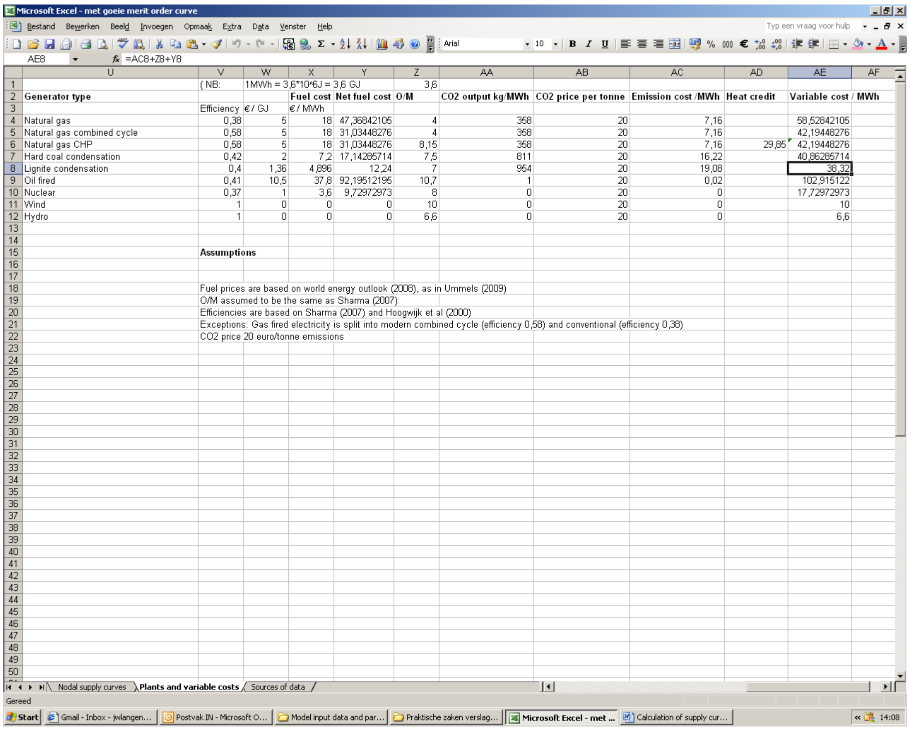
CO_2 emission permit prices

Since the introduction of the Kyoto protocol, purchasing the necessary emission permits forms an additional cost associated with the generation of electricity in Europe. The price can be quite volatile – at the time of writing, it was at €13 (Point Carbon, 2009), but in the long term it may be expected to rise. The estimates used by Sharma (2007) and in the world energy outlook 2008 for 2015 are €20 and €25 respectively. In this case, €25 will be adopted as the initial value, but the model validation will include a sensitivity analysis looking at the impact this choice has on model outcomes. Combined with an estimate for the emissions, this gives the emission costs displayed in table 38.

Table 38: Emission intensity and resulting cost per MWh

Energy technology	Emission price (€ / tonne)	Emission intensity (kg CO2 / MWh)	Emission cost (€ / MWh)
Hard coal condensation	20	811	€16,22
Lignite condensation	20	954	€19,08
CHP natural gas	20	358	€7,16
Natural gas combined cycle	20	358	€7,16
Oil	20	1	€ 0,025

The resulting estimates for marginal cost prices are calculated in a spreadsheet, as shown in the screenshot (see Figure 30).



Generator type	Efficiency	€/ GJ	Fuel cost €/ MWh	Net fuel cost	O/M	CO2 output kg/MWh	CO2 price per tonne	Emission cost /MWh	Heat credit	Variable cost / MWh
Natural gas	0,38	5	18	47,36842105	4	358	20	7,16		58,52842105
Natural gas combined cycle	0,58	5	18	31,03448276	4	358	20	7,16		42,19448276
Natural gas CHP	0,58	5	18	31,03448276	8,15	358	20	7,16	29,85	42,19448276
Hard coal condensation	0,42	2	7,2	17,14285714	7,5	811	20	16,22		40,86285714
Lignite condensation	0,4	1,36	4,896	12,24	7	954	20	19,08		38,32
Oil fired	0,41	10,5	37,8	92,19512195	10,7	1	20	0,02		102,915122
Nuclear	0,37	1	3,6	9,72972973	8	0	20	0		17,72972973
Wind	1	0	0	0	10	0	20	0		10
Hydro	1	0	0	0	6,6	0	20	0		6,6

(NB: 1MWh = 3,6*10^6J = 3,6 GJ 3,6

Assumptions

Fuel prices are based on world energy outlook (2008), as in Ummels (2009)
O/M assumed to be the same as Sharma (2007)
Efficiencies are based on Sharma (2007) and Hoogwijk et al (2000)
Exceptions: Gas fired electricity is split into modern combined cycle (efficiency 0,58) and conventional (efficiency 0,38)
CO2 price 20 euro/tonne emissions

Figure 30: screenshot of spreadsheet used to estimate marginal cost

The resulting marginal cost prices per MWh for the base case scenario are given in the table 24.

Table 39: Marginal cost price of production estimates per technology

Cost of production (euro/MWh)	Energy technology
6,6	hydro
10	wind
17,72973	nuclear
38,32	lignite
40,86286	hard coal
42,19448	NGCC
42,19448	NG CHP
58,52842	NG turbine

2) Division of supply by energy technology and quantity per node in the network

The division of power plants has been estimated. Existing plants were found by taking the declared capacity data from the Dutch TSO Tennet for the first quarter of 2010 (Tennet, 2009a). The new plants listed in the quality and capacity plans for 2008-2014 were then added, based on those connections that have been granted(Tennet, 2008b). A plant planned in Geertruidenberg by Essent has been cancelled since publication of the quality and capacity plans, so this was not taken into account. The Nor-Ned and Brit-Ned cables were assumed to be used to import hydropower and power produced by NGCC plants respectively.

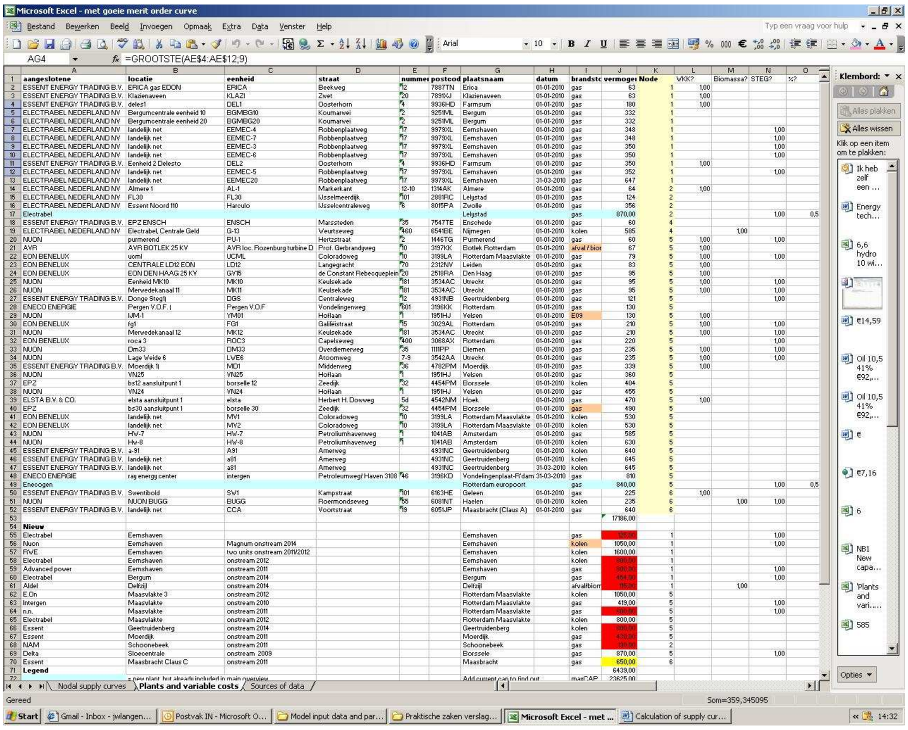


Figure 32: spreadsheet used to calculate capacity per location in the Netherlands

The resulting data was combined into a spreadsheet, to allow easy calculation of the resulting capacity at each location in the network. The screenshot (Figure 32) shows the resulting overview of plants in the Netherlands. The data was then used to estimate supply curves for each node, as is visualized below in Figure 31.

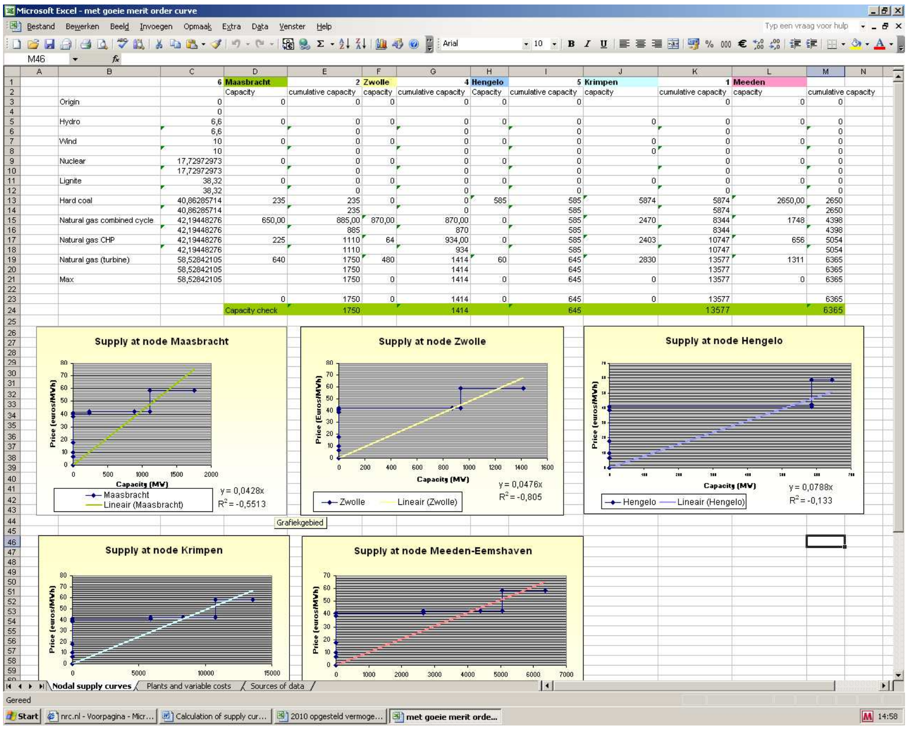


Figure 33: spreadsheet used to illustrate supply curves per location in the Netherlands

3) Estimation of parameters using SPSS based on combinations of capacity and marginal prices per node

Although the supply curves can be roughly estimated using the spreadsheet as shown in step 2, more precise statistical analysis can be done using purpose built software for data analysis. The data from the sheet were therefore entered into the software package SPSS, in order to allow supply curves to be estimated for each node. Below, the curves and relevant parameters are given. The R square value may be interpreted as indicating to which extent the variation in the ‘real’ data is explained by the parameters estimated for the curve. It is higher for the two nodes (1 and 5, i.e. Meeden and Krimpen) with the largest amount and variation in generating capacity. This is not unexpected, given that these curves are estimated on the basis of a larger number of data values).

Table 40: Slope of Dutch supply curves

Node	**Slope**	**R square value**
1	c(i1) = 0,009	0,966
2	c(i2) = 0,044	0,658
4	c(i4) = 0,077	0,809
5	c(i5) = 0,05	0,985
6	c(i6) = 0,038	0,710

4) Estimation of supply curves for Belgian, French and German nodes

As is noted elsewhere in this thesis (see Chapter 3), the model used for the quantitative research is based on an aggregated representation of the electricity markets and networks of neighbouring countries. This section of this annex explains the methodology used to calculate supply curves for the nodes in these countries, and briefly discusses the assumptions and simplifications involved.

Belgium

Belgium is represented by two nodes in the model. Data concerning existing and future Belgian plants was derived from documents and data in the public domain (Elia, 2009b) and(Elia, 2009a). Assumptions on future capacity also draw on the supply adequacy forecasts of UCTE (2008) and Ummels (2009).

This information was compiled in the form of a series of spreadsheets which allow calculation of linear supply curves, based on a least squares regression as is described in the first section of this annex. Screenshots of the relevant spreadsheets are given as an indication (see Figures 34 and 35).

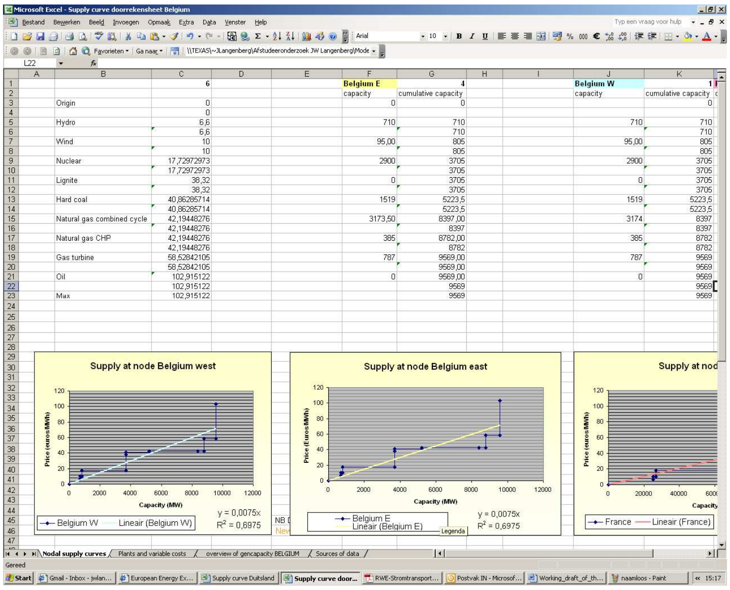
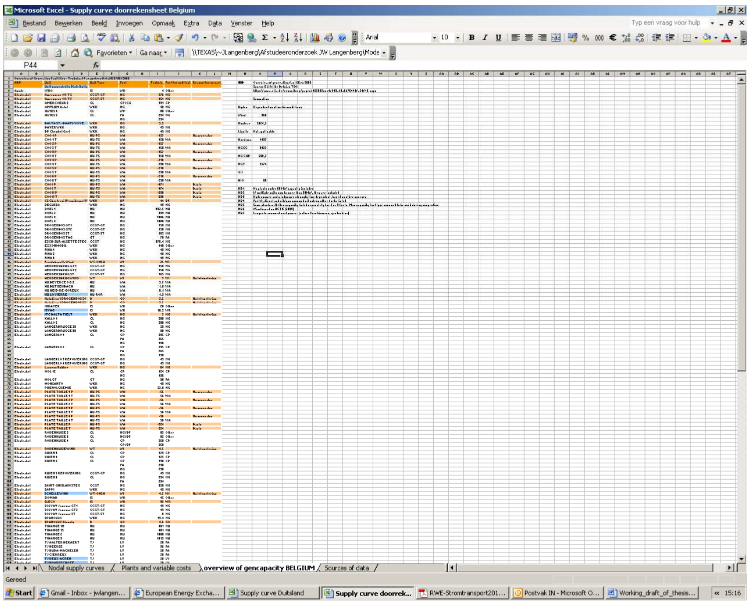


Figure 34: screenshot of spreadsheet with Belgian supply curves



Belgium is mainly relevant for congestion within the CWE region as a transit point between the Netherlands and France, rather than as a result of internal congestion. Its nodes are therefore simply assigned half of the national capacity for electricity generation each.
This allows more accurate representation of the interconnectors, while saving time which would otherwise be spent investigating the geographical distribution of Belgian power plants, which is deemed to exceed the scope of this research.

Figure 35: screenshot of spreadsheet with Belgian power plants

The resulting parameters for the curves are also given in table 26.

Table 41: Slope of Belgian cost curves

Node	Slope	R square
10	c(i10) = 0,0075	0,6975
11	c(i11) = 0,0075	0,6975

France

France is represented in an aggregated form, using a single node connected to Belgium and the south of Germany. French generation is dominated by nuclear capacity. Estimates for available capacity for the year 2014 were derived from UCTE data based on (UCTE, 2008) and Ummels (2009). A screenshot of the spreadsheet constructed with this data is given (see Figure 36).

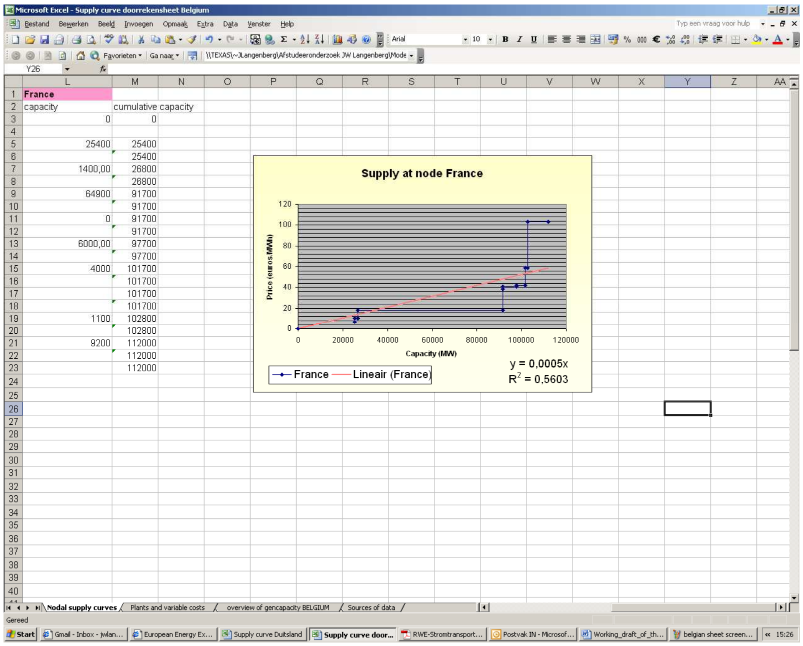


Figure 36: screenshot of spreadsheet with French supply curve

A supply curve was estimated using a least squares regression as described in the first section of this annex. The resulting curve parameters are given in table 27.

Table 42: Slope of French supply curve

Node	Slope	R square
12	0,0005	0,5603

Germany

Representing the western part of Germany accurately is important for this research, as congestion in this part of the CWE region can translate into congestion within the Netherlands and vice versa. However, modelling the whole of the German network to the same level of accuracy as that applied for the Netherlands would require data estimation and a model beyond the means and time available for this research.

The approach chosen compromises between the desired accuracy and complexity by representing the western most regions of the German networks. More specifically, the control areas along the border are taken into account. Node 7 in the model covers regions 0 and 2 along the north western border region falling under the TSO Transpower[50]. Node 8 covers regions 1-5 of the TSO RWE Transportnetz. Finally, node 9 represents regions 1 and 2 of the TSO associated with the company EnBW.

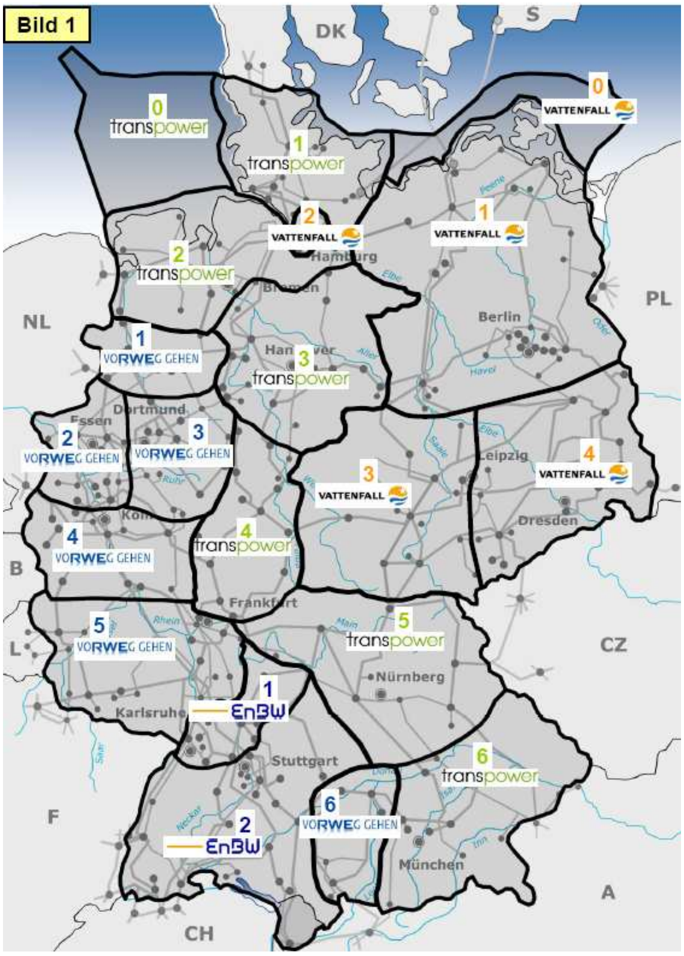


Figure 37: German network regions and TSOs

In order to estimate generation capacities, data available from sources in the public domain (Transpower, 2009), (RWE Transportnetz, 2009), (ENBW, 2009) and (EEX,2009) was compiled into a series spreadsheets. The screenshots given (see Figure X) give an indication of the structure of the calculations involved.

[50] Transpower is a subsidiary of the E.On group

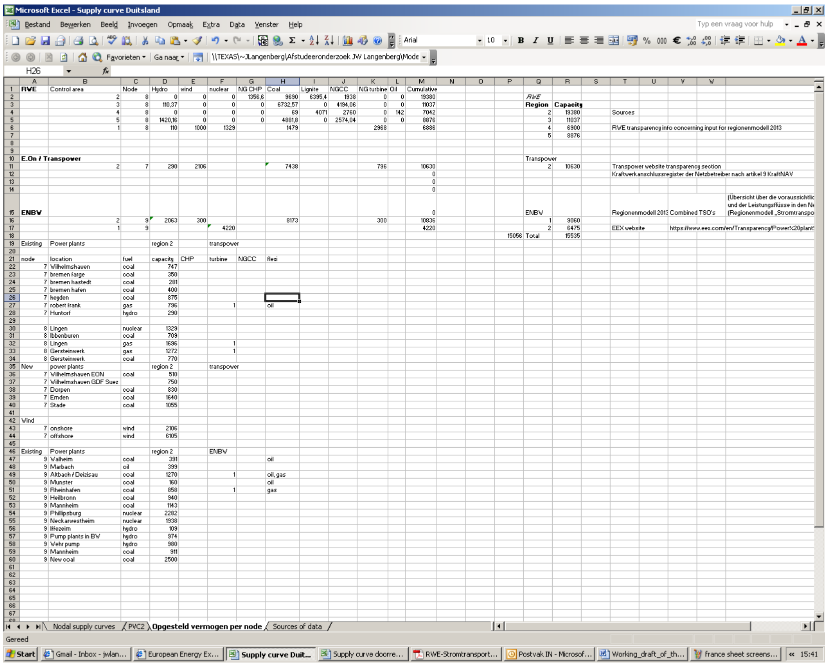


Figure 38: Screenschot of spreadsheet with German plants

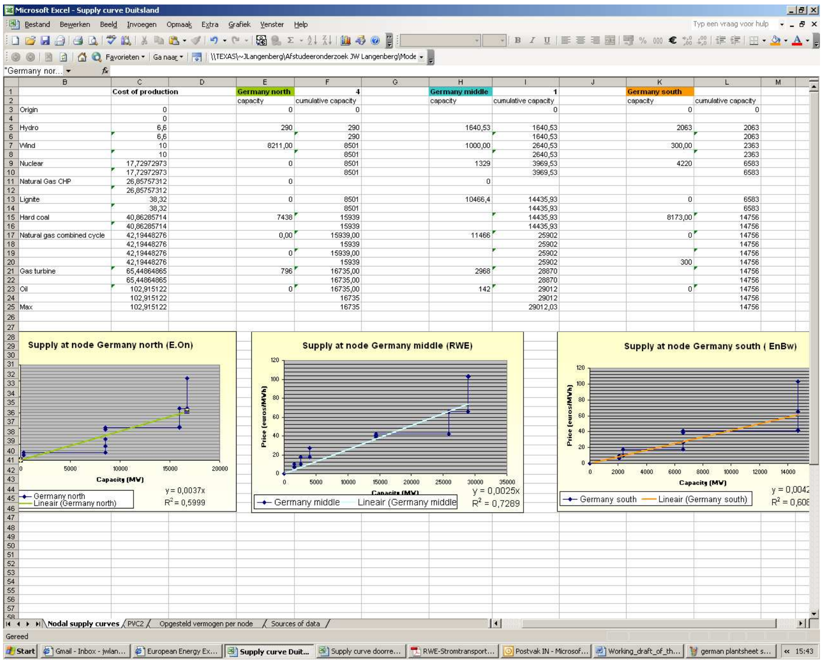


Figure 39: Screenschot of spreadsheet with German supply curves

A number of German plants are able to run on multiple fuel types. It was assumed that these would be run on the basis of the cheapest fuel in the merit order (i.e. coal for the base case scenario).

The resulting curves should be considered to be relatively rough estimates of the true situation regarding German generation capacity in 2014, as a truly thorough representation would require a more detailed analysis of expectations concerning new plants and more accurate data than is currently easily accessible. The parameters for the curves are indicated below.

Table 43 Slope of German supply curves

Node	Slope	R square
7	0,0037	0,5999
8	0,0025	0,7289
9	0,0042	0,6084

Annex 5 Estimation of parameters related to demand curves

This annex describes the relevant methodology, assumptions and data which were involved in the calculation of the demand curves for each node in the model.

The demand for electricity should also be specified per node in the network. The simplest way in which to deal with demand is to find a value for the national demand, and then divide it equally over the network. This may allow modelling of the effects of managing congestion within a generic network, but is not very realistic for a country such as the Netherlands.

(Bjørndal et al., 2003) simply state they divided demand in a way that they believe 'comes close to the realistic situation for the Norwegian and Swedish network', and represented this by linear demand curves with a parameter for the (negative) slope. The cut-off price (the maximum which will be paid for electricity) is represented by a parameter which is equal for all nodes.

Sharma and de Jong (2007) use a single national reference market outcome. They determine the price associated with this quantity of demand based on the assumption that at this price the supply and demand curve will be in equilibrium, so that substituting the chosen level of demand into the supply curve gives a price. They then combine the maximum quantity of supply possible with a price level of 0 to determine a second point. Fitting a linear curve between these two points results in an inverse national or regional demand curve for electricity. The procedure and result is visualized below (see Figure 40). This procedure must be adjusted when demand is spread over multiple nodes within a national network, to take into account a realistic distribution.

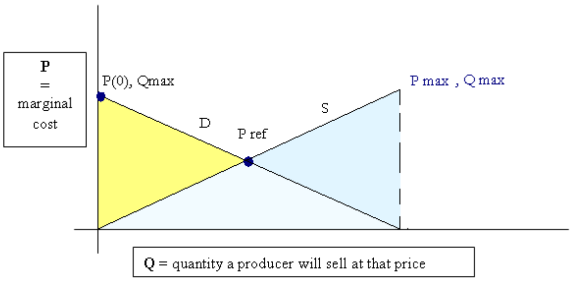


Figure 40: Linear curve estimation

Estimating demand curves for nodes with the Netherlands

For the Dutch nodes in this model, where demand is to be divided geographically the approach of (Leuthold et al., 2008) is used to quantify this distribution. These authors, when modelling the effects of nodal pricing for the German network, chose to use the division of GDP over the country as a proxy for electricity demand. Using public data relating to the division of gross value added (for industry and services) and gross domestic product (for residential demand), a proportion of economic activity per district may be derived. The share of national gross value added for the node compared to the national total can then be used.

This share of production can be combined with a generic measure of electricity use per sector per unit of value added or of residential demand for the country as a whole, to determine an average electricity demand at that node. Once this is then matched with predicted demand, either the same procedure can be followed as was applied by Sharma and de Jong (2007), or alternatively a chosen level of demand elasticity a linear demand curve specific to that node could be used to give an inverse linear demand curve.

Data for estimating the value of demand for the Netherlands in 2014 nationally was the assumed load from the TSO's forecast(Tennet, 2008b). This estimates growth in demand to 17.782MW (from 15.334 MW in 2008).

As the methodology described above for estimating the regional division of demand has been carried out in 2006 by the TSO, Tennet (TenneT, 2006). This study estimated the demand distribution at the municipal level: a higher level than is relevant for the nodes in this model. The data were therefore aggregated into a spreadsheet allowing for a division of demand according to the allocation of demand per province to each of the five Dutch nodes. A screenshot (see Figure 41) illustrates the procedure.

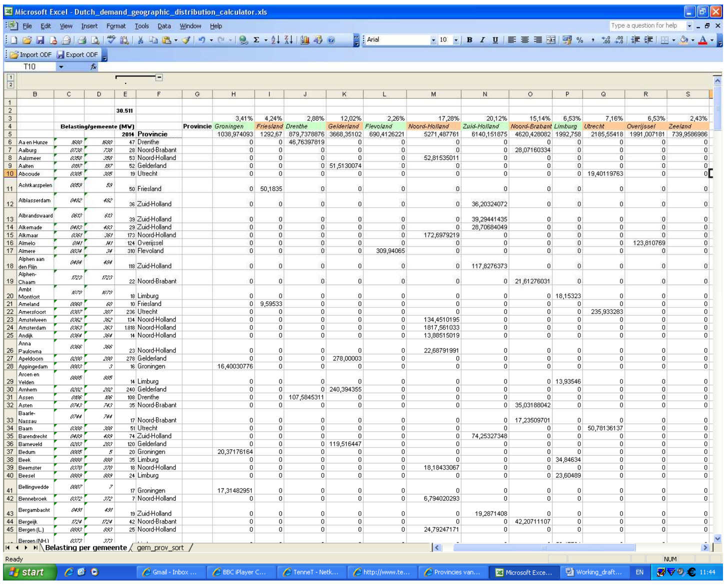


Figure 41: screenshot of spreadsheet used to calculate provincial demand for electricity

By allocating the provinces to the relevant nodes, and dividing provinces where necessary, a rough share of electricity demand per node could be derived. This share is combined with the demand national prediction above to give the demand prediction per node, as shown in the table below.

Table 44: Division of demand for electricity over Dutch nodes

Country / node	Provinces allocated to node	Share of demand %	Share of demand MW (2014)
Netherlands (Krimpen)	North/ South Holland, Zeeland, Utrecht, ½ of North Brabant	54	9702
Netherlands (Meeden-Eemshaven)	Friesland, Groningen, ½ of Drenthe	9	1615
Netherlands (Zwolle)	Overijssel, ½ of Drenthe	10	1819
Netherlands (Hengelo)	Gelderland	12	2137
Netherlands (Maasbracht)	Limburg, ½ of North Brabant	14	2507

The equations for the Dutch supply curves, based on the estimation of marginal costs described in Annex 4, each take the linear form given in generalised terms below:

$P_s(i) = b(i) * Q_s(i)$ (a10)

Substitution of the predicted national demand in an aggregated demand curve gives average price to use for each demand curve:

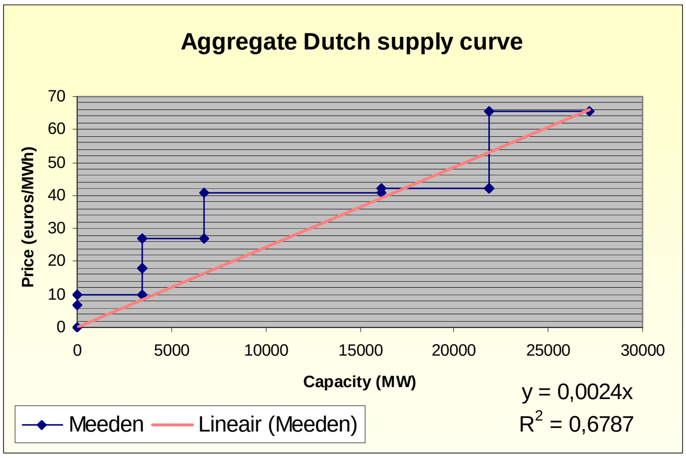


Figure 42: aggregate Dutch supply curve

$P_s(i) = 0{,}0024*17.782 = 42{,}68$ euro / MWh (a11)

To find a second data point, we assume that at a (hypothetical) price of 0 euro /MWh, all national capacity would be consumed. Assuming the demand is then divided over the regions according to the spread indicated above, a second point can be determined and a linear function estimated. The resulting demand curves can therefore be given using the following parameters for the intercept value and the slope (see table below, and graphs for an indication of the slope of both linear approximations of the demand and supply curves.

Table 45: Parameters of demand curves for Dutch nodes

Parameter	Represents	Node 1	Node 2	Node 4	Node 5	Node 6
a	intercept (= max price)	125,678	129,114	123,851	125,981	125,172
b	slope of curve	0,051393682	0,047518985	0,037984905	0,008586294	0,032905763

Estimating the Belgian and French demand curve for 2014

In order to determine demand curves for the two Belgian nodes in the network, a similar simplification is applied to that used for supply curves. The relevant parameters are estimated first on a national scale. Demand is then assumed to be divided equally over the two nodes. For France, only a single node is modelled, so nationally aggregated figures can be used.

National demand for electricity in 2014 for Belgium is estimated based on an extrapolation using the same assumed growth rate for the period between 2010 and 2015 as is assumed in the UCTE system adequacy forecast 1,7 % (2008), using a simple spreadsheet. The same is done for France, using the growth rate (1%) for 2010-2015 from that publication. A screenshot of the relevant spreadsheet has been included (see Figure X) as an indication.

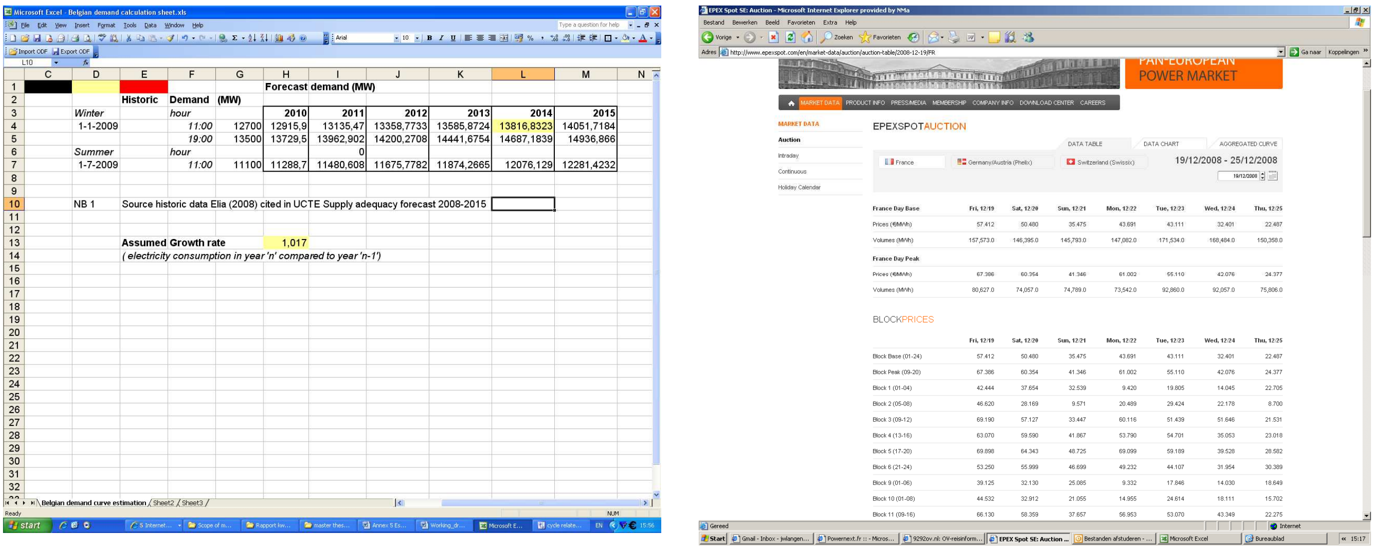


Figure 43: screenshot of Belgian demand curve spreadsheet and Powernext prices

These capacities are then compared with reference market prices from the electricity exchanges for these countries, to give a data point on the demand curve (a screenshot of the market data website for the Powernext French auction is shown above).

The results of the demand estimation are shown below.

Table 46: Estimated peak national demand in 2014 for Belgium and France

Country / node	Demand (01-01-2009)	Assumed rate of growth (per year)	Estimated demand (01-01-2014)	Reference price (Euro/MWh) (17-12-2008)
Belgium (2x)	12,7 GW	1,7 %	13,8 GW	82,24
France	82,7 GW	1,0 %	86,9 GW	77.624

The two equations for the Belgian supply curves, based on the estimation of marginal costs described in Annex 4, are given below:

$$P(S, Belgium) = 0{,}0075 * Q(S) \qquad \text{(a12)}$$

Substitution of the predicted demand gives one point on the demand curve:

$$P(S, Belgium) = 0{,}0075 * (12{,}7 * 10\wedge 3MWh)/2 = 47{,}625 \text{ euro / MWh} \qquad \text{(a13)}$$

The net maximum capacity is 9569MW per node, which can be combined with a price of zero to give the second data point for estimating the curve.

The resulting demand curve can therefore be given using the following parameters for the intercept value and the slope (see table32, and Figure 44 for an indication of the slope of both linear approximations of the demand and supply curves.)

Table 47: Parameters of Belgian demand curve

Parameter	Represents	Value
a	intercept (= max price)	141,6212
b	slope of curve	-0,0148

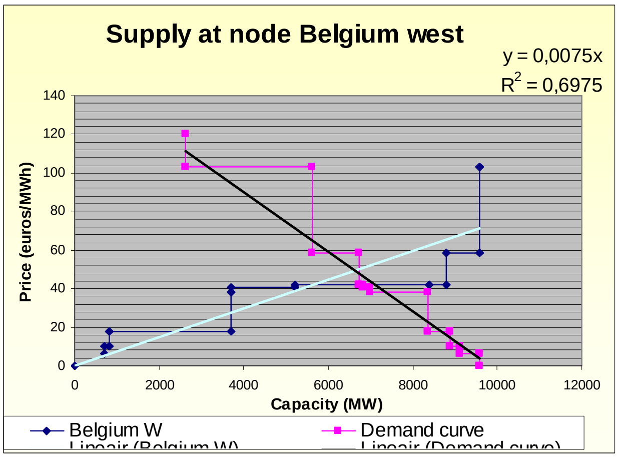


Figure 44: graph illustrating Belgian demand and supply curves

The equation for the French supply curve, based on the estimation of marginal costs described in Annex 4, is given below:

P_s(France) = 0,0005 * Q_s(France) (a14)

Substitution of the predicted demand gives one point on the demand curve:

P_s(France) = 86900 * 0,0005 = 43,45 euro / MWh (a15)

The net maximum capacity is 112000 MW, which can be combined with a price of zero to give the second data point for estimating the curve.

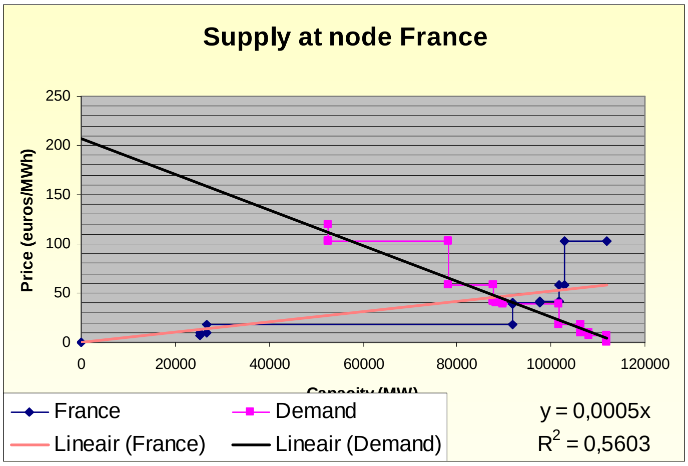


Figure 45: graph illustrating Frenchdemand and supply curves

The resulting demand curve can therefore be defined using the parameters for the intercept value and the slope given in the table. The graph gives a rough indication of the relation between the linear approximations of both demand and supply curves compared to what step functions in practice might look like.[51]

Table 48: Parameters of French demand curve

Parameter	**Represents**	**Value**
a	intercept (= max price)	193,88
b	slope of curve	-0,00173

Estimating the German demand curves using demand for 2014

In order to determine regional demand curves for the aggregated areas represented by the three German nodes in the network, the values for future load per region[52] given in the forecast published by the German TSO's for their regions was compiled using a spreadsheet (see Figure 46).

[51] Note for example that due to the way the spreadsheet calculates the trend line, the value for the intercept with the y – axis is overestimated. In practice, once a certain price is reached, demand may become vertical (completely inelastic or unresponsive to price changes) and in practice, there are also caps on maximum spot prices that can be reached at times of low supply.

[52] The regions used are the same as those chosen for supply, see Annex 4 for details.

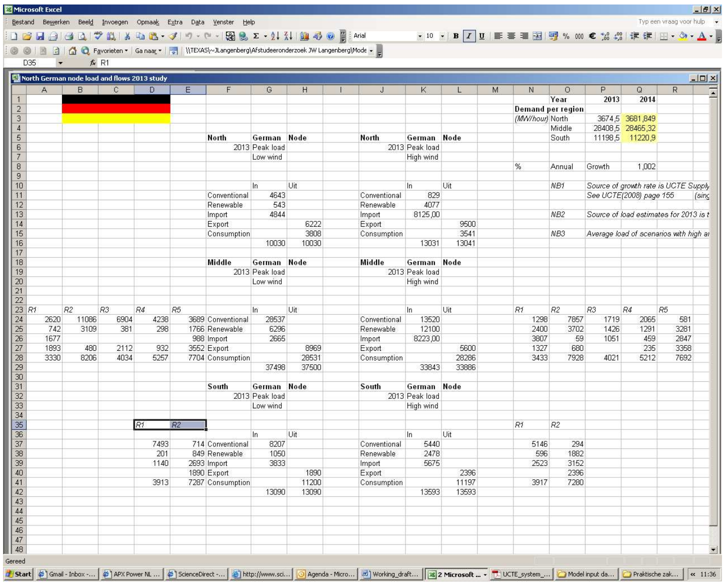


Figure 46: Screenshot showing a spreadsheet used for German demand calculation

The average value of load was taken from the high demand / high wind capacity and high demand / low wind capacity scenarios when these differed. This ensures a similar situation is being assumed as given in the UCTE supply adequacy forecast studies, which are based on "*…standard weather conditions*" (2008, page 32).

As these values are based on a forecast for 2013, they are increased using the average annual growth rate assumed in the UCTE supply adequacy forecast for the period between 2010 and 2015[53](2008, page 115).

This allows the calculation of average load estimates for 2014, as displayed in the table below. Reference prices were found for a comparison with current peak prices.

Table 49: German peak demand growth estimates for 2014 per region

Country / node	Demand (forecast for 2013)	Assumed rate of growth (per year)	Estimated demand (MW, 2014)	Reference price (19-12-2008)[54] (Euro/MWh)
Germany (north)	3675	1,002	3681	63.06
Germany (middle)	28408	1,002	28465	63.06
Germany (south)	11198	1,002	11221	63.06

The three equations for the German supply curves, based on the estimation of marginal costs described in Annex 4, are given below:

53 Specifically, the annual growth rate assumed is 0,2%.
54 Data from the EPEX Spot market website (2009).

$$P(S, Germanynorth) = 0,0037 * Q(S) \qquad (a16)$$
$$P(S, Germanymiddle) = 0,0025 * Q(S) \qquad (a17)$$
$$P(S, Germanysouth) = 0,0042 * Q(S) \qquad (a18)$$

Substituting the predicted national demand given by UCTE (2008) for 2014 in a national supply curve based on a regression of predicted supply , similar to the regional gives a reference price for power curves (see Figure 47).

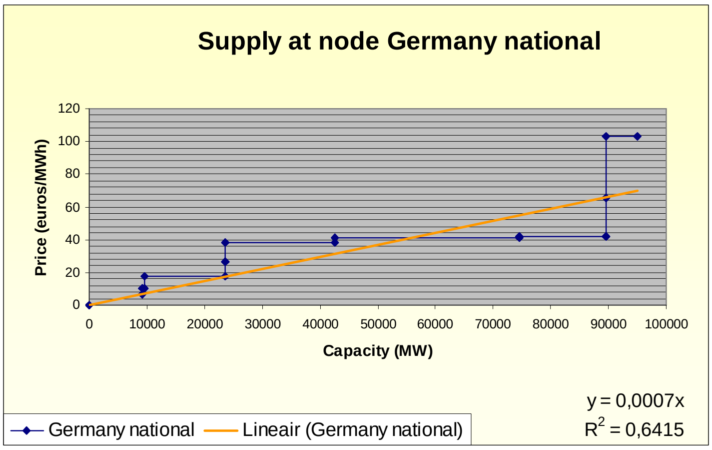


Figure 47: aggregate Dutch supply curve

This is then coupled with the predicted regional demand to give a first point on each demand curve.

P(d) = 0,0007'* q(d) = > = 0,0007 * 77500 = 54,25 (a19)

so these points are as follows:

Table 50: Data points on the German demand curves per region (national demand and price prediction)

Country / node	Demand (forecast for 2013)	Assumed rate of growth (per year)	Estimated demand (MWh, 2014)	Estimated price (Euro/MWh for 2014)
Germany (north)	3675	1,002	3681	54,25
Germany (middle)	28408	1,002	28465	54,25
Germany (south)	11198	1,002	11221	54,25

The net maximum demand is found by assuming that the proportion of national demand consumed by each region will remain the same as the price of power decreases. If this is coupled with the assumption that on a national scale, when a price of 0 Euros per MWh occurs, all power capacity is used, a second data point can be found for each region representing the intercept of the demand curve with the x axis.

The resulting demand curves can then be given using the parameters for the intercept value and the slope given in the tables beside the graphs given below. Each equation can be generalised in the algebraic form $p_d(i) = a - b * q_d(i)$ (see also chapter three).

Table 51: Parameters of German supply curves

Country / node	b	$a=b(Q_{d,max})$
Germany (north) i7	0,065642691	295,8807471
Germany (middle) i8	0,008488697	295,8807471
Germany (south) i9	0,021533798	295,8807471

Annex 6: Estimation of safety margin with regard to maximal thermal capacities of transmission lines and resistance of lines

This annex describes the sources which have been consulted in order to find the values used for indicating the maximal capacity constraint for the amount of power that can be transported during a single hour over any one transmission line in the quantitative model used for this research.

Although data are available for the thermal capacity limits of the lines, these cannot simply be assumed to be available for transport of traded electricity. A safety margin is always employed, in order to ensure that the grid can continue to function safely when components fail. If any one component were to fail this is known as an 'n-1' margin, if the margin is sufficient for two components to fail without impeding, it is 'n-2' and so on. Furthermore, although this model is a 'DC' model based on a linearization, in real operation part of the transmission capacity will also be needed to deal with the occurrence of reactive power, further reducing the 'usable' transmission capacity.

Available capacity on interconnectors between national networks

For the interconnections between countries, the NTC capacity estimates (Entso-E, 2009)can be adopted as an estimate of the cumulative capacity available for day-ahead trade in the market (see table below). Although in practice efforts are taking place which will allow more precise flow based modelling of actual capacity, this can be seen as a relatively conservative estimation of the capacity on connections spanning national borders[55]. Where the estimates diverge, the lower capacity is given.

Table 52: NTC values for Dutch borders for winter 2009

Border	NTC 2009 winter (MW)	Includes links	Comments
NL-DE	3000	1-7, 4-8, 6-8	
NL-BE	2400	5-10, 6-10, 6-11	
BE-FR	2200	10-12, 11-12	
FR-DE	2750	12-9	Includes interconnectors not given in model, such as those that go to the RWE control area represented by node 8.

[55] Tennet, the Dutch TSO, employs a Transmission Reliability Margin (TRM) of 300 MW for these connections, which according to Haubrich et al. (2001, page 158) is based on "*statistical analysis of observed amounts of inadvertent exchange plus a (small) surplus for uncertainty on system conditions beyond the portion already coped with by explicitly considering different scenarios*"

Table 53: Interconnector capacity values and reactance used in the model

Link	Interconnection	Nominal capacity (MW)	Value assumed for model	Reactance used in model (Ohms)
1-7	Meeden – Diele	3290	825	15,32
4-8	Hengelo – Gronau	3290	825	5,64
12-9	France – Germany South		2750	25,4
5-10	Krimpen – Belgium West	1645	800	18,84
6 – 10	Maasbracht – Belgium West	1645	800	21,66
6 - 11	Maasbracht – Belgium East	1645	800	17,48
6-8	Maasbracht-Rommerskirchen/Siersdorf[56]	3420	1350	16,03
10-12	France – Belgium West	unknown	1100	55,4
11-12	France – Belgium East	unknown	1100	45,2

Sources: (Tennet, 2008d), (Hobbs and Rijkers, 2004b), (Entso-E, 2009)

Transmission line capacity estimation within the Dutch high voltage grid

Estimating interconnections within the Netherlands is difficult to do precisely, as no data similar to NTC values for interconnectors are available in the literature. Furthermore, the model aggregates certain lines in order to simplify the work of representing flows, but this complicates the estimation of the capacity of the links because in practice power may flow over several lower voltage lines in parallel, or over multiple high voltage lines in series which are represented by single links in the model.

A starting point is the available data on thermal capacity limits given by the TSO (Tennet, 2008d) for existing 380kV lines (see the table below).

Table 54: Transmission line data for Dutch transmission links

Transmission line	Length (km)	Reactance per circuit (Ohms)	Circuits (#)	Capacity per circuit (MVA)	Represented in the model by:
Diemen-Lelystad-Ens	71,4	19,78	2	1645	L(2,5)
Ens-Zwolle	32	9,66	2	1645	L(2,5)
Meeden –Zwolle	107,7	20,75	2	2750	L(1,2)
Meeden – Eemshaven	37,6	8,76	2	2750	L(1,2)
Zwolle – Hengelo	60,2	15,75	2	1645	L(2,4)
Hengelo – Doetinchem	58,7	16,17	2	1645	L(4,6)
Dodewaard – Boxmeer - Maasbracht	99,7	27,72	2	1645	L(4,6)

[56] Two circuits in parallel

Krimpen – Geertruidenberg	99,5	9,67	2	1645	L(5,6)
Geertruidenberg – Eindhoven	63,9	19,35	3	1645	L(5,6)
Maasbracht – Eindhoven -	48,7	13,43	2	1645	L(5,6)

. For the purpose of this model, it is assumed that a safety margin of 1/3 is sufficient for internal transmission lines. Where multiple lines are combined with different capacities, the lower is taken as use the lower as indicative of the limitation to maximum flow.

As stated elsewhere (see Chapter 1), transmission losses are not deemed to be significant with respect to the economic outcomes of electricity trade and congestion management. However, in order to model the transmission flows through the network realistically, taking the differing resistances of lines into account is necessary.

The reactance of multiple links in series can be found by adding the individual reactances. When multiple circuits are in parallel, the aggregate reactance can be found by adding the reciprocal of the sum.

The resulting values are summed up in the table below. The sensitivity analysis investigates the impact of varying this assumption for the model outcomes.

Table 55: Values used in model for transmission line aggregate capacity and reactance

Line in model	**Capacity assumed (MVA)**	**Aggregate reactance used in model (Ohms)**
L(1,2)	3666,67	14,71
L(2,5)	2193,33	14,72
L(5,6)	2193,33	18
L(4,6)	2193,33	28,08
L(2,4)	2193,33	7,875

Estimation of internal transmission links between German nodes and between Belgian nodes

Estimation of the internal transmission capacity between the German nodes is a difficult exercise, both because the scope of the aggregation involved in the representation of the West German network is significant and because the German TSO's are not unbundled from competing actors on the power markets, and not all the necessary technical information is therefore available in the public domain due to confidentiality considerations.

A solution was found by adopting the values used in an earlier ECN publication by Hobbs and Rijkers (2004b). These values were based on a slightly different network representation with 4 nodes and should therefore be considered to be an approximation. They are based on an initial study by Haubrich et al. (2001). Resistance is estimated to be proportional to the length of the lines.

Belgium is divided into two nodes in the model, but no regional differentiation is assumed. The capacity assumed for these nodes is therefore taken to be equal to that of most of the Dutch lines; the resistance is taken as an average of the two Dutch links running from west to east.

Table 56: Transmission line values used in model for capacity and reactance of German and Belgian transmission links

Line in model	Capacity assumed (MVA)	Reactance used in model (Ohms)
L(7,8)	1842	69,2
L(8,9)	1842	43
L(10,11)	2193,33	20

Annex 7: Validation of flow equations in the network model through algebraic derivation from generalised 'DC' load-flow equations

As described in Annex 2, equations governing the flows of electricity in network within the model have been derived based on network theory and Kirchhoff's laws. An example is shown using the figure on the right. This cycle gives the first equation shown at the end of this page. In this annex, the algebraic steps needed to relate the resulting equations to the more general form of equations used to define the models that are based on 'DC' linear load-flow approximations are described.

The number of such independent equations in a network of n vertices and m links can be shown to equal m-1+1, where 'm' represents the number of links and 'n' the number of vertices or nodes in the network (Dolan and Aldous, 1993). In this case therefore, (17-121+1) = 6 equations are necessary (KV1-6).

KV1: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) - X_{5,10}*(q_{5,10}) = 0$

KV2: $X_{10,11}*(q_{10,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV3: $-X_{6,10}*(q_{6,10}) + X_{6,11}(q_{6,11}) + X_{11,12}*(q_{11,12}) - X_{10,12}*(q_{10,12}) = 0$

KV4: $-X_{2,5}*(q_{2,5}) - X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{5,6}*(q_{5,6}) = 0$

KV4: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{6,8}*(q_{6,8}) - X_{4,6}*(q_{4,6}) - X_{2,4}*(q_{2,4}) = 0$

KV5: $-X_{1,2}*(q_{1,2}) + X_{1,7}*(q_{1,7}) + X_{7,8}*(q_{7,8}) - X_{4,8}*(q_{4,8}) - X_{2,4}*(q_{2,4}) = 0;$

KV6: $X_{6,8}*q_{6,8} + X_{8,9}*q_{8,9} + X_{9,12}*q_{9,12} - X_{11,12}*q_{11,12} - X_{6,11}*q_{6,11} = 0$

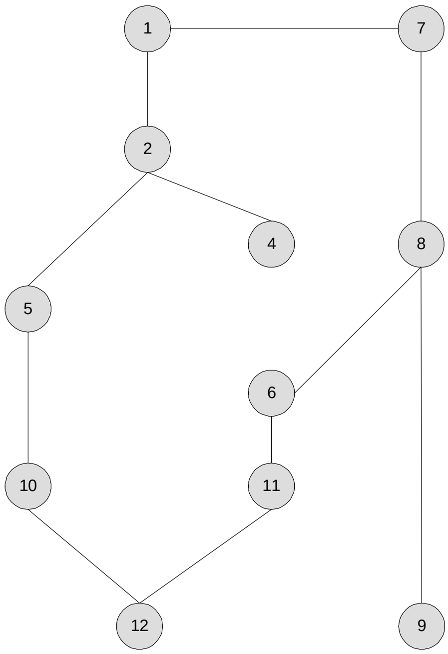


Figure 47: cycle in the network model

In each case, the notation $q_{i,j}$ represents a flow from node 'i' to node 'j' if positive and from 'j' to 'i' when the sign is negative. The 'direction' given to the links mentioned earlier is thus from 'i' to 'j'. Note that here, the impedance is not yet included (or alternatively, can be considered to be equal for all the links).

Algebraic steps involved in deriving equations

The 'DC' load-flow approach can be summarized in the form of two equations relating the flow (PF(i,j)) between nodes to their voltage phase angles (Theta(i)) and the susceptance ($1/X_{ij}$)of the transmission line linking them (Wood and Wollenberg, 1995), (Schweppe et al, 1988):

$P_F(i,j) = 1/X_{ij} * (Theta(i) - Theta(j))$ (a20)

and for each node:

$P(i) = sum(P_F(ij))$ where j is an element of j, representing all nodes connected to i. (2)

Here, we start by applying equation (1) to the links between nodes 10, 11 and 12 in the network model:

P_F (10,11) = 1/$X_{10,11}$ * (Theta(10) – Theta (11)) (a21)
P_F (10,12) = 1/$X_{10,12}$ * (Theta(10) – Theta (12)) (a22)
P_F (11,12) = 1/$X1_{1,12}$ * (Theta(11) – Theta (12)) (a23)

Next, we rewrite these equations by multiplying both sides of each equation by the reactance of the link in question. As the susceptance is equal to the inverse of the reactance, this gives:

$X_{10,11}$ * P_F (10,11) = Theta10 – Theta11 (a24)
$X_{10,12}$ * P_F (10,12) = Theta10 – Theta12 (a25)
$X_{11,12}$ * P_F (11,12) = Theta11 – Theta12 (a26)

Now, it is possible to combine these equations, by subtracting the second from and adding the third to the first:

$X_{10,11}$ * P_F (10,11) - $X_{10,12}$ * P_F (10,12) + $X_{11,12}$ * P_F (11,12) = 0 (a27)

As can be seen from the above, this eliminates the variables representing the phase angles from the resulting equation. The result conforms to the equations KV2 as given above (note the notation in the model is $q_{i,j}$ rather than $P_F(i,j)$. The validity of the other equations listed KV1 and KV 5-7 can be deduced in a similar fashion.

The second generalized equation relates to the equations denoted KC 1-12 in Annex 2. By combining this with the first equation, for all the links connected to the node in question, the specific equations can be found as used in the model. As an example, node 9 is considered.

P (i9) = P_F89- P_F9,12 (a28)

Adopting the model notation, we find:

Q_i(i9) = $Q_{8,9}$ – $Q_{9,12}$ (a29)

This is equal to equation KC9 as noted in Annex 2. The other equations are similar in form.

Annex 8: Overview of the quantitative changes to model input for the scenarios

The table below reproduces the changes made to the base case scenario in order to create the other scenarios. A fuller qualitative description is given per scenario in Chapter three of this thesis (3.5), but the changes are based on developments related to the available generation capacity, the CO_2 permit price and the wind conditions.

Table 57: Overview of scenario input

Scenario => **Input**	**Base case**	**Scenario B**	**Scenario C**	**Scenario D**
D(Generating capacity)	2500 MW of wind in Ijmuiden	4400 MW wind in Ijmuiden, 1000 MW wind in Eemshaven	5000MW wind in Ijmuiden, 400 MW wind in Eemshaven	(1400) MW nuclear power in France
Wind availability	25% of rated capacity	100% of rated capacity	100% of rated capacity	25% of rated capacity
CO_2 permit price	20 euro/tonne	20 euro/tonne	40 euro/tonne	20 euro/tonne

Annex 9: Investigation into French supply curve parameters

The French supply curve leads to large overestimations in price, as the linear regression forces a higher cost level to be estimated for the large 'step' of cheap nuclear power.

To find out if this leads to unrealistic results, an attempt is made to increase realism by investigating the effects of the curve, leaving out the power plants that are more expensive than nuclear. This changes the parameter of the cost curve to c=0,03, effectively reducing the cost of French power by more than half. See Figure X.

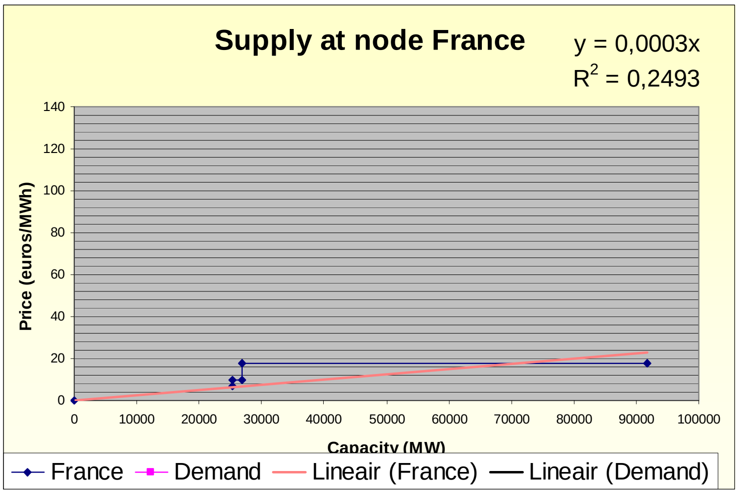


Figure 48: Adjusted French supply curve

To show the effects this would have on the model, the base case is first run again. The diagrams below show how this effectively reverses flows in the south of the region. A better balance between French and German imports allows for less potential problems within the German network due to North-South transport. Note that French demand is fixed at the level calculated previously, and that transmission is unconstrained (see Figure 49).

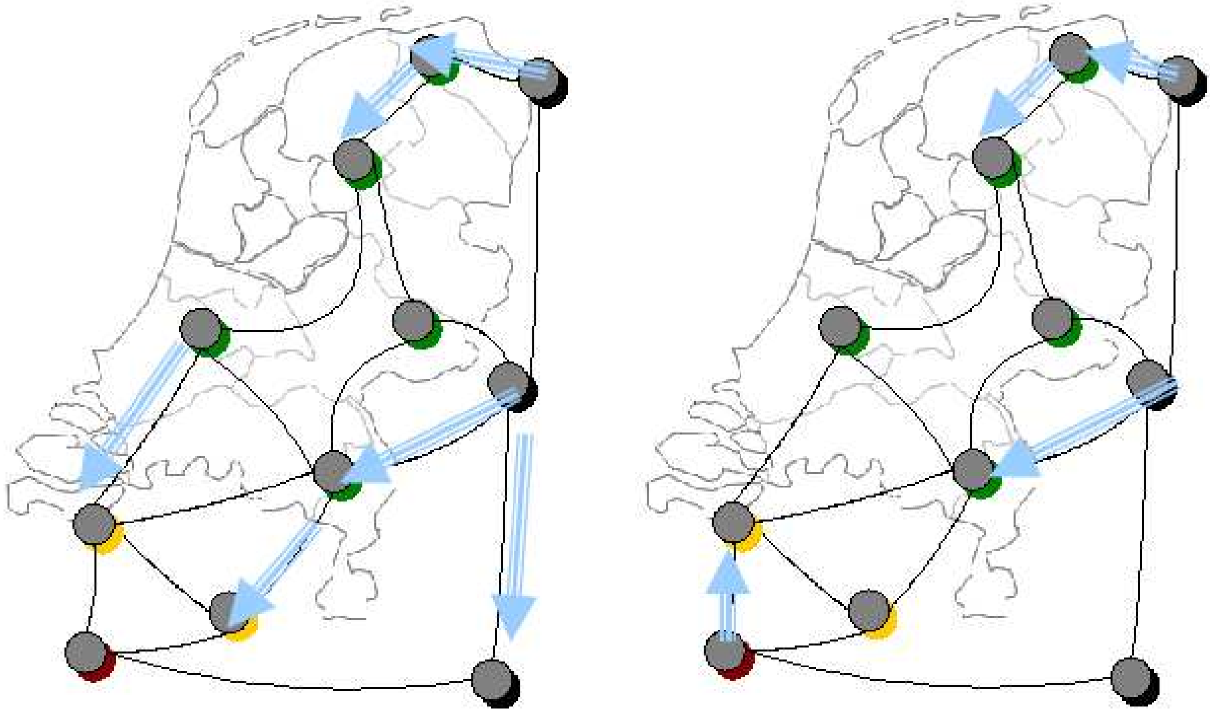


Figure 49: changes in flows from adjusted French supply curve

Though the effects of changing French supply on transmission appear to result mainly in rebalancing the transmission in Belgium and the south of Germany, these outcomes suggest that the aggregated economic indicators and the prices should be interpreted as rough estimates at best. Further investigation of the way in which the French market works may be necessary to gain more confidence in the model output with regard to this part of the region.

Table 58: Effects of changing French suplpy curve on model output

Output	Base case (full French curve)	Base case (short and cheap French curve)
Marginal price $p_d(i)$	42,69	40,03
Total Production cost	3,5*10^6 Euros / hour	2,7*10^6 Euros / hour
Net French exports	-1992 MW	4311 MW

The approach chosen in the model research, as described in chapters three and four of this thesis is likely to be closer to the truth if the marginal price is effectively set by fossil fuelled plants in the French market. This approach may be less accurate if long term contracts and strong regulation drive the nuclear plants responsible for the bulk of power production.

Either way, more complex modelling and economic research into the variable costs of the various French nuclear power plants would be necessary for truly accurate assessment of this market.

Annex 10: German and Dutch fuel mixes and supply curves

This annex gives a more detailed insight into the fuel mix under the conditions assumed for scenario C. This scenario was created in order to investigate the occurrence of trade between the west and the east of the CWE region, but the model output did not reveal significant Dutch exports to Germany. To investigate how this could occur, the aggregate fuel mix for both countries was looked at in more detail, as is visually displayed below in the Figure 50 and quantitatively in table 44.

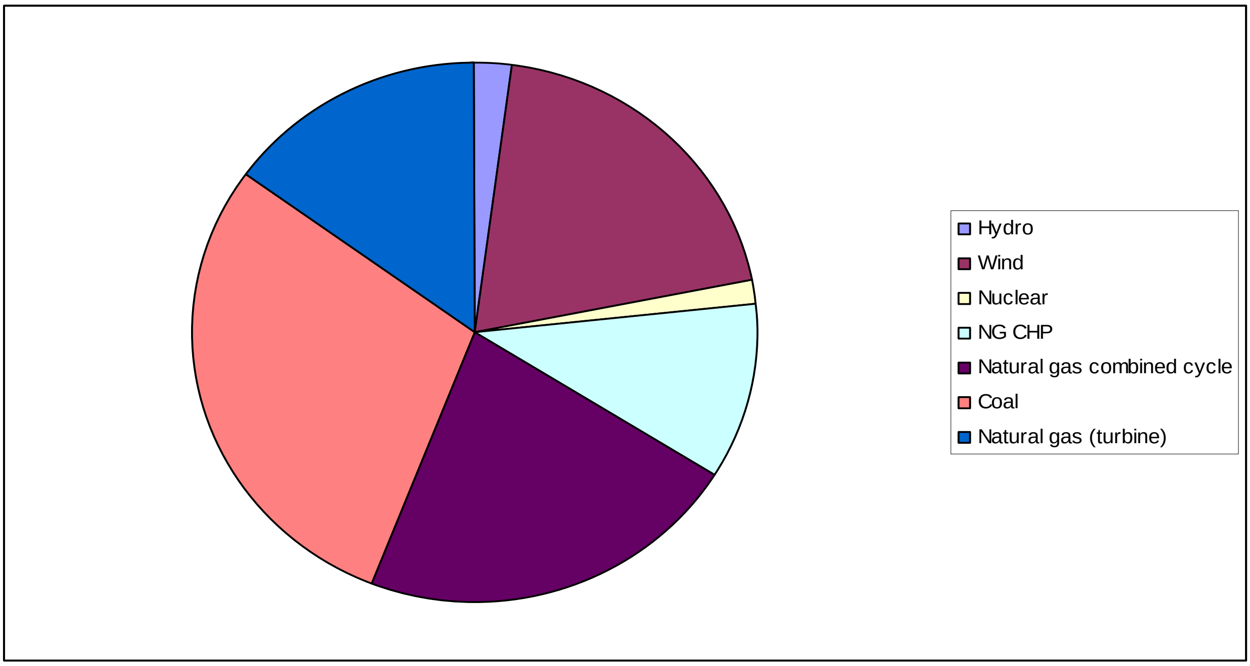


Figure 50: Dutch fuel mix

Table 59: Fuel mix Dutch supply for scenario c

Dutch mix	**Hydro**	**Wind**	**Nuclear**	**NG CHP**	**NG CC**	**Coal**	**NG turbine**
%	2,18 %	19,65 %	1,52 %	10,41 %	22,19 %	29,04 %	15,02 %
# (MW)	700	6320	490	3348	7138	9344	4831
CUMULATIVE	700	7020	7510	10858	17996	27340	31171

German mix	Hydro	Wind	Nuclear	NG CHP	NG CC	Coal	Lignite	Gas turbine	Oil
%	5,13	3,05	7,13	1,74	14,73	49,37	13,45	5,22	0,18
# (MW)	3993	2377	5549	1356	11466	38427	10466	4064	142
CUMULATIVE	3993	6371	11920	13276	24742	63169	73635	77699	77841

Table 60: Fuel mix German supply for scenario c

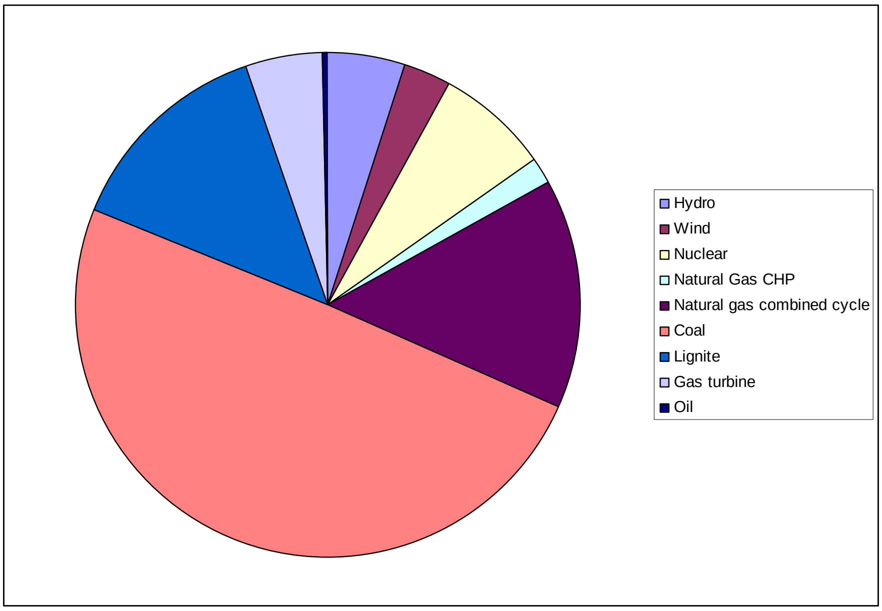


Figure 50: German fuel mix

What can be deduced from this information? German demand in the model output is 44.284MW, Dutch demand is 16.399 MW. Looking at the fuel type which would set the marginal price at these quantities, we can see that this would be natural gas combined cycle in the Netherlands but coal in Germany. Nevertheless, the costs for production are the same in both countries!

This is due to the smoothing effect that the linear supply curves have on the costs of production. This can be confirmed by looking at a cumulative German supply curve (see Figure 51).

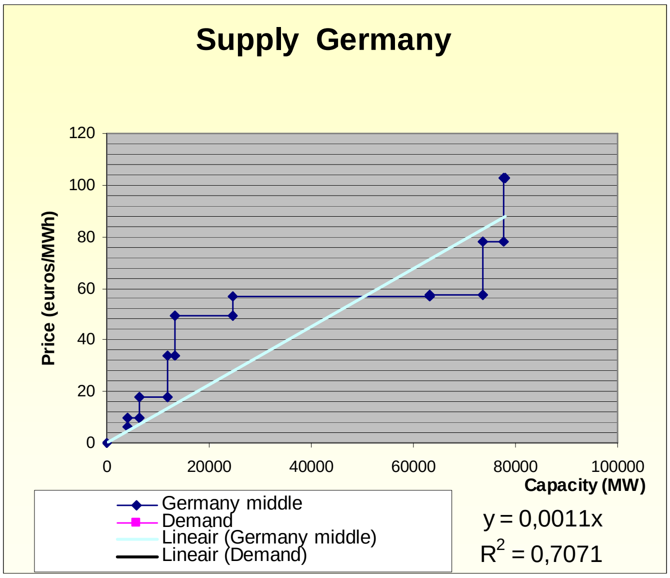


Figure 52: aggregate German supply curve for scenario c

From the beginning of the part of the curve covering gas fired capacity, there is quite a strong under estimation of the costs (and therefore, an overestimation of the surplus) resulting from increased production. This problem is less significant in the Netherlands, although underestimation is also the case here (see Figure 53).

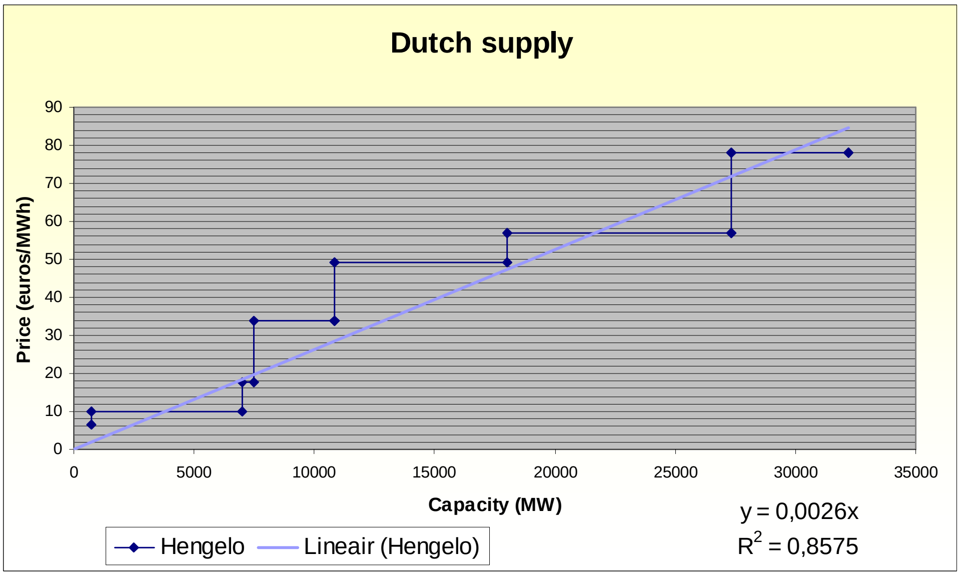


Figure 53: aggregate Dutch supply curve for scenario c

This is an example where implementing step functions would make German prices more expensive and Dutch supply more competitive! More realistic would be that under these conditions, Dutch gas fired supply would be fully dispatched, leading to 1600 MW higher Dutch generation, and displacing the same amount of German coal fired supply. This could lead to the result that we would intuitively expect: Dutch exports to Germany.

However, it is important to remember that power is now also traded in the direction of the Belgian border, where price differential is higher. Also, the amounts of power that are exported will appear de factor within the supply of the importing country.

Furthermore, the model does not use national curves but regionally differentiated ones, so taking this into account may change the result (especially given nodal or zonal pricing assumptions).

Annex 11: Overview of parameter changes per scenario

This annex shows changes in parameters per scenario compared to the base case. The qualitative changes these are used to describe are indicated in Annex 8.

The table (see table 46) shows changes to the slope in the supply curve parameter c.

Table 61: Scenario cost parameters

Node	base case	scenario b	scenario c	scenario d
1	0.0092	0.0075	0.0129	0.0092
2	0.0484	0.0368	0.0588	0.0484
4	0.0823	0.0823	0.01178	0.0823
5	0.0041	0.0031	0.0041	0.0041
6	0.0448	0.0448	0.057	0.0448
7	0.0063	0.0037	0.008	0.0063
8	0.0013	0.0013	0.0017	0.0013
9	0.0042	0.0042	0.0053	0.0042
10	0.0075	0.0075	0.0079	0.0075
11	0.0075	0.0075	0.0079	0.0075
12	0.0005	0.0005	0.0006	0.0006

Scenario B involves increased wind power in the north of Germany and the Netherlands. This is reflected in decreased supply cost curve parameters for nodes like 1 and 7. Scenario C describes a scenario involving an increase in the CO_2 price, which results in a cost price increase across all nodes. The exception is in the west of the Netherlands, as this scenario assumes increased wind deployment there. Scenario D involves a supply side shortage in France, whereas the other parameters are unaltered from the base case.

All parameters were found using a linear regression analysis as described elsewhere in this thesis (see Annex 2-5).

Annex 12: Calculation of yearly congestion cost estimates based on wind conditions

In order to translate the hourly results from the scenarios to yearly totals, we need to know how many hours per year the relevant conditions occur during peak load conditions. The amount of hours can then be estimated roughly using the formula defined in equation A14.1

# of hours in which congestion occurs = # of hours in a year * % high wind hours* % peak load demand hours (A14.1)

Wind speed varies both seasonally and from year to year. Data from the Dutch office of statistics (CBS, 2009) give a monthly index (called the Windex) which indicates whether production was high or low compared to yearly averages. This index is strongly correlated with the number of hours during which the production of the existing wind turbines is at a maximum (Segers, 2009a personal communication).

In order to find a rough estimate of the amount of hours during which the highest wind production took place in a year, the number of months in which the windex indicator was over 100 were found for the last three years. This percentage of the hours in a full year was then multiplied by a percentage of 25% to find a rough estimate of the number of hours during which both peak load and peak wind conditions may occur. This allows for a rough estimate of the relevant number of hours to be in the range of 500 to 1000 hours per year, using data calculated by Segers (2009b) for the last three years (see table 69) .

Table 62: Overview of calculation of hours during which congestion due to wind may take place

Year	months with windex > 100	total hours / year	% peak demand	Hours with high wind during peak demand
2005	3	8760	25	547,5
2006	6	8760	25	1095
2007	3	8760	25	547,5

The level of congestion costs in a year can then be roughly estimated by multiplying the amount of hours in which congestion take place by the level of congestion costs reported in chapter 4 of this thesis, as shown in equation (A14.2).

Yearly congestion costs = congestion cost estimate * (# of hours in which congestion occurs)

The resulting cost estimates (see Table 70) suggest that the deployed wind power leads to yearly congestion costs of around 41 million Euros for scenario B or 33, 3 million Euros for the base case in conditions comparable to 2005 or 2007. For wind conditions in a year such as 2006, the costs are estimated to be double this figure: 82 million Euros or 66 million Euros respectively.

Table 63: Yearly congestion cost estimates for scenario B and base case

High wind / peak demand hours	Yearly costs b	Yearly costs base case
547,5	€ 41.001.180	€ 33.397.500
1095	€ 82.002.360	€ 66.795.000
547,5	€ 41.001.180	€ 33.397.500