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Congestion management in the Dutch power sector: a quantitative evaluation of policy options

Master Thesis
MSc Systems Engineering, Policy Analysis & Management (SEPAM)

M.J. van Blijswijk
Student #: 1268279

Delft University of Technology
Faculty of Technology, Policy & Management

TenneT TSO B.V.
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Graduation Committee:

Prof. dr. ir. M.P.C. Weijnen (chair)	Energy & Industry
Dr. ir. L.J. de Vries (first supervisor)	Energy & Industry
Dr. A.F. Correljé (second supervisor)	Economics of Infrastructures
Dr. G. van der Lee (external supervisor)	Regulation & Grid Economy (TenneT)
Dr. ir. B. Broekhans	Board of Examiners

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Student #: 1268279

Institution:

Delft University of Technology
Faculty of Technology, Policy & Management
Jaffalaan 5
2628 BK Delft
The Netherlands

TenneT TSO B.V.
Regulation & Grid Economy
Utrechtseweg 310
6812 AR Arnhem
The Netherlands

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Graduation Committee:

Prof. dr. ir. M.P.C. (Margot) Weijnen (chair)	Energy & Industry
Dr. ir. L.J. (Laurens) de Vries (first supervisor)	Energy & Industry
Dr. A.F. (Aad) Correljé (second supervisor)	Economics of Infrastructures
Dr. G. (Gert) van der Lee (external supervisor)	Regulation & Grid Economy (TenneT)
Dr. ir. B. (Bertien) Broekhans	Board of Examiners

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Preface

As the final deliverable of roughly two years work in the Systems Engineering, Policy Analysis & Management (SEPAM) MSc program, this report serves as the capstone of my educational career at the faculty of Technology, Policy and Management (TPM) of Delft University of Technology. I began studying at TPM in 2005, when I enrolled in the BSc program *Technische Bestuurskunde*. I had only a vague idea of the relevance of interdisciplinary skills and was primarily driven by my diverging interests that I sought to somehow combine. Years of classes, exercises, research papers, and other projects have taught me how complex problems that we face in the world today cannot be solved by readily available solutions that can be applied by engineers, economists, policy makers, or any other sole discipline. These problems force people of different backgrounds to communicate and to cooperate in finding the answers to the pressing issues we face as a society.

During my years of studying at TPM I have gradually developed a specialization in the field of energy, with a personal fascination for the electricity sector. The physical characteristics of electricity and the economics of its infrastructures add a thrilling dimension that is both unique and challenging. This particular interest for the electricity sector was the main reason for me to contact TenneT when I was searching for an interesting topic for my graduation project. TenneT, which is the Dutch transmission system operator and in charge of operating the high voltage grid, is a perfect example of an organization that operates in a complex field where multiple disciplines meet. At the core of its business lies the complex technological task of ensuring a reliable and uninterrupted power supply throughout the Netherlands. It must perform this task in a liberalized electricity sector, where independent actions are taken by generators and loads that cannot always be (fully) predicted, let alone influenced. Because the transmission infrastructure constitutes a natural monopoly, TenneT must furthermore operate within boundaries set by a regulatory framework that is put in place to ensure fair and equal competition on the Dutch electricity market. And the above is not limited to national borders: TenneT operates as a part of a large interconnected European electricity system, with decisions made hundreds of kilometers away directly affecting the Dutch power system.

One of the important current developments for TenneT is the introduction of congestion management. With the aim to enhance competition on the Dutch electricity market, generators that construct new production units will no longer have to wait until the required transmission system reinforcements are complete before they are connected to the grid. Whenever a situation arises under which transmission capacity is insufficient to physically implement the flows that are scheduled by market parties, the application of a congestion management must ensure that no power flows are imposed that exceed grid capacity. This report is written for TenneT and will, considering its role with respect to achieving societal objectives, analyze the appropriateness of the currently applied congestion management method in comparison with other available methods, which are argued to yield better outcomes by some authors. Congestion management is expected to be applied in the province of Zuid-Holland starting from May 2011, and the aim of this project is to determine what effects its application will have for TenneT and for society, in order to find out whether the method currently applied is indeed the most appropriate and desired mechanism for coping with congestion in the Netherlands.

Working on the subject of congestion management has been a challenging and interesting task, and I am particularly glad to have had the opportunity to work on my graduation project in combination with an internship at TenneT. This has greatly aided me with finding the required information and data, and in addition brought the knowledge that is available inside the organization within arm's reach. I expect the insights found by this study to prove helpful for TenneT and its approach towards congestion management, and that they serve as an enrichment for scientific literature on the topic.

Summary

Due to the introduction of a new grid connection policy, transmission system operator TenneT expects congestion to arise on the Dutch transmission grid in the near future. This new connection policy was introduced by the Ministry of Economic Affairs to abolish the discrimination between existing grid users and new entrants, and should improve competition. It allows generators to be connected to the grid directly, without having to wait for transmission capacity expansions that may be required. As this could cause transmission flows as desired by market parties to exceed the available capacity, TenneT must apply congestion management in order to guarantee the safe and reliable operation of the transmission grid.

The Ministry decided that *basic system redispatch* should be used to manage congestion. This method was regarded the most appropriate short-term implementable option available, but has some drawbacks nonetheless. In existing literature it is argued that it potentially leads to high costs, that it is vulnerable to strategic bidding, and that it creates economically sub-optimal outcomes from a grid efficiency perspective. This study has quantitatively evaluated the application of the method in the Netherlands, in terms of congestion costs, their allocation, the incentives it creates, and the opportunities for (and the consequences of) generators bidding strategically. These outcomes were compared to three other congestion management methods (market splitting, market coupling, and the APX-based method[1]), in order to assess the validity of the proposition that market-based methods, which form the current trend in Europe, lead to better outcomes.

Using a quantitative model of the Dutch electricity system the application of all four congestion management methods was simulated. This was done under four different scenarios, each of which was based on extreme conditions that were expected to contribute to congestion in parts of the grid:

- Low wind availability in Germany
- Cheap natural gas
- Green revolution
- Code red

The simulations revealed that the transmission link between the Maasvlakte region and the Ring is most prone to become congested. However, this study also found that the resulting congestion costs will be low. This is the case because the variable cost levels of production units in the areas upstream and downstream from the congested grid segment were found to be very similar. A deviation from optimal dispatch will therefore result in only slightly higher dispatch costs. Under the most extreme scenario conditions, in which 1292 MW needs to be redispatched from the Maasvlakte to other areas of the Netherlands, net congestion costs were found to be € 231 / hr. On a yearly basis this would be € 2 mln., which is significantly lower than cost estimates found in literature, which expect this cost to be in the order of magnitude of € 10–100 mln.

To identify the most appropriate congestion management method for the Netherlands, multi-criteria decision analysis (MCDA) was applied to compare the methods, in a pairwise manner and on the basis of eleven criteria. The analysis revealed that conflicting objectives preclude the identification of a single most appropriate congestion management method. It found that the APX-based method outranks market splitting and market coupling, but it remained inconclusive with respect to the appropriateness of basic system redispatch in comparison with these methods. The policy objectives of the Ministry thus appear to be different from those presumed elsewhere and by existing literature, considering their explicit preference for market-based methods.

In order to improve the results of this analysis, the Ministry must reassess its objectives with respect to the conflicting criteria of proportionality, and long-term generator and TSO incentives. Also, additional research should improve the conclusiveness of the model results that were used for MCDA, as this would contribute to a more conclusive recommendation on method appropriateness. In particular, such research should encompass the options for incorporating a renewable energy compensation scheme under market-based methods, and it should, by constructing a more extensive, continuous, agent-based model that is capable of incorporating the strategies pursued by individual generators, provide a broader insight and more detailed data on the extent of congestion and the (resulting) consequences of strategic bidding.

1 A description of these methods is provided in Appendix B.

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List of abbreviations

Abbreviation	Full
AC	Alternating Current
ARGUS	Achieving Respect for Grades by Using ordinal Scales only
ATC	Available Transfer Capacity
C,off	Constrained off
C,on	Constrained on
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power
CM	Congestion Management
CO_2	Carbon Dioxide
DC	Direct Current
DG	Distributed Generation
DSM	Demand-side Management (see Appendix B)
ECI	Extent of Congestion Index
ELI	Ministry of Economic Affairs, Agriculture, & Innovation[2]
EMCC	European Market Coupling Company
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
GW	Gigawatt
HC	Hard Coal
HVDC	High Voltage Direct Current
ISO	Independent System Operator
KPI	Key Performance Indicator
kV	Kilovolt
kWh	Kilowatt-hour
LMP	Locational Marginal Pricing (see Appendix B)
MC	Market Coupling
MCC	Market Coupling Capacity
MCDA	Multi-Criteria Decision Analysis
MCF	Market Coupling Flow
MCP	Market Clearing Price
MVA	Megavolt-ampere
Mvar	Megavolt-ampere reactive
MW (MWh)	Megawatt[3] (Megawatt-hour)

2 Dutch: Ministerie van Economische Zaken, Landbouw en Innovatie.
3 Throughout this document all instances of MW should be interpreted as MW_e, unless explicitly stated otherwise.

MW_e	Megawatt (electric)
MW_{th}	Megawatt (thermal)
NG	Natural Gas
NMa	Nederlandse Mededingingsautoriteit (Dutch Competition Authority)
NTC	Net Transfer Capacity
OBK	Order book
OCGT	Open Cycle Gas Turbine
PFD	Power Flow Distribution
PSI	Pivotal Supplier Index
PTDF	Power Transfer Distribution factor
PX	Power Exchange
RSI	Residual Supply Index
SEP	Samenwerkende Elektriciteitsproducenten (Cooperating Electricity Producers)
SO	System Operator
STEG	*See CCGT*
TCC	Transmission Congestion Contract (see Appendix B)
TO	Transmission Owner
TSO	Transmission System Operator
TSW	Total Social Welfare

List of symbols

Symbol	**Definition**
C	Capacity
L	Load
Δp	Price difference
P	Production capacity
Q_a	Accepted quantity
Q_P	Quantity of electric power [MW]
S_i	Surplus of stakeholder i
x	Reactance of a power line, in Ω per km
X	Total reactance, in Ω

Codes used to refer to congestion nodes

Code	**#**	**Location**	**Area**
NN	1	North Netherlands	All subnets connected to the 380 kV infrastructure in Friesland, Groningen, Drenthe, Overijssel, including Noord-Oostpolder (the rest of Flevoland is part of node RN). Note that the complete 380 kV ring infrastructure itself, including its elements located in Overijssel, is a part of node RN.

Codes used to refer to congestion nodes

RN	2	Ring	380 kV ring-structure and all subnets connected to it, i.e. Noord-Holland, Flevoland (excluding the Noord-Oostpolder), majority of Gelderland, Utrecht, Noord-Brabant (except the area west of Zevenbergschenhoek / Princenhage), Limburg, and Zuid-Holland (excluding the Rotterdam industrial area and the Westland region).
MV	3	Maasvlakte	Rotterdam industrial area, including the Maasvlakte, and the Westland region.
ZL	4	Zeeland	Zeeland, including the western part of Noord-Brabant (west of Zevenbergschenhoek / Princenhage).
DE	5	Germany	
BE	6	Belgium	
NO	7	Norway	
UK	8	United Kingdom	
For more information on these nodes, their coverage areas and borders, please refer to Appendix D.3.			

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PART I:
Introduction to Congestion Management

1 Introduction

In the liberalized Dutch electricity market both producers and consumers have a free choice in the geographical siting of their facilities. The transmission grid is in place to physically transport all electricity that is traded amongst these parties. Although allowing market players to freely trade electricity amongst each other, the liberalization of the electricity market has not affected the physical characteristics of electricity even the slightest bit, and continuous grid monitoring remains of the utmost importance in order to assure its safe operation.

1.1 Transmission system operation: a brief history

Before 1998, until the electricity market was restructured, all electricity generation facilities were publicly owned by local and provincial governments. These power producers cooperated through a venture called SEP (Cooperating Electricity Producers, Dutch: Samenwerkende Elektriciteitsproducenten) which coordinated the dispatch, construction, and decommissioning of power plants. This cooperation allowed for efficient usage of the available production capacity and transmission grid, as SEP could dispatch plants and site new facilities in the most optimal manner based upon the complete knowledge it had (TenneT, 2008). Transmission grid constraints could be managed relatively easily, as SEP had the authority to geographically locate capacity in manner such that it was consistent with transmission grid capacity. Grid constraints of a more incidental nature were solved by its authority to adjust the production levels of all plants, which it could use in order to avoid excess flows in parts of the grid.

Since 1998, the system operation tasks of SEP are carried out by TenneT TSO B.V., a company wholly-owned by the Dutch national government. TenneT, unlike its predecessor SEP, can no longer decide on the geographical siting of production facilities as this decision should be made by the market parties wishing to invest in production capacity. Yet, TenneT is in principle legally obliged to connect new capacity to the grid and provide sufficient transmission capacity to ensure safe and reliable operation of the grid. Also, it does not possess the authority to unilaterally impose restrictions or obligations on generators with respect to production levels. The only exceptions to this rule are acute emergency situations which require immediate action. One could say that, at the very least, these conditions have made grid operation much more challenging compared to the times when SEP could single-handedly coordinate investments in, and the use of, the transmission infrastructure.

Under European legislation (Directive 2009/72/EC) all TSOs are obliged to connect all parties to the grid that have requested so, on a transparent and non-discriminatory basis, insofar as capacity of the transmission system is sufficient to ensure safe and reliable operation. Also, TSOs are legally obliged to provide sufficient transmission capacity to accommodate market needs. In the past, if grid capacity was insufficient, TenneT could delay this access until the necessary reinforcements were implemented or until capacity became available due to other reasons, such as the decommissioning of old production units. The Minister of Economic Affairs[4] found this practice to be discriminatory towards new entrants and preferred a system in which market players would be allowed immediate access to the grid, thus without having to wait for capacity to become available (NMa, 2009, Article 34). The removal of this entry barrier to the electricity market was meant to enhance competition, which should eventually lead to lower prices. The consequence of lifting of this entry restriction, however, is that it can cause a situation in which parts of the grid become – either occasionally or structurally– physically unable to cope with the demand for transportation.

1.2 Congestion in electricity grids

Congestion is a term that can be (and is) applied to many types of systems, dealing with all sorts of flows, e.g. traffic flows, information flows, or water flows. Although the general definition of the

4 As of September 2010 the Ministry of Economic Affairs is integrated into the (new) Ministry of Economic Affairs, Agriculture, and Innovation (Dutch: Ministerie van Economische Zaken, Landbouw en Innovatie). Its tasks and responsibilities with respect to energy-related affairs remain unchanged.

cause of congestion is similar, the consequences are rather different for different system. In its simplest form congestion can be defined as the supply of an entity of some class, that exceeds the infrastructure capacity that is needed to transport those entities. Traffic congestion, for instance, is conceptually easy to grasp: when the inflow of vehicles to a road exceeds the capacity of that road to handle those vehicles, traffic congestion (i.e. a traffic jam) will be the result. Data infrastructure can also become congested: if the packet processing capacity of an Internet router is insufficient to handle all incoming packets requesting transportation, incoming packets may need to queue before being processed. Although the process is not visible to the human eye and therefore perhaps less well understood, the result is similar to traffic congestion: a slowdown in network traffic, i.e. a slower download speed and longer loading times for web pages.

Although conceptually similar, electricity congestion does not result in a 'traffic jam of electrons' of any kind. Due to its physical characteristics, electricity can actually not become “congested” in a manner similar to other systems. In fact, it does – simply stated – not matter to electricity whether the maximum capacity of a power line is exceeded or not. Unlike a road experiencing a traffic jam, electricity will not queue if too much of it is supplied, and it will keep flowing anyhow. While this characteristic would appear to preclude congestion to exist in the first place, it has an unfortunate side-effect to it. When an electrical current is transported through a power line, the line will heat up as a result of its electrical resistance. Technically, the capacity of a power line is therefore not defined by the number of electrons it can handle, but by the amount of power that it can transport without its temperature exceeding the limits of safe and reliable operation. The maximum capacity of a power line is thus determined by the amount of current that can be transported while keeping the temperature of the line within safe margins. This capacity is generally set such that it applies under all weather and wind conditions, and includes a safety margin.

> ***Influence of weather conditions on grid capacity***
>
> *A power line is limited in capacity because of its maximum allowable temperature, rather than its “true ability” to cope with electrons vibrating in a 50 Hz pattern. Variations in outside temperature can therefore influence the maximum capacity of a line, because lower temperatures and higher wind speeds provide more cooling to the line which in turn leads to an increase in the amount of power that can be transported before the maximum temperature threshold of the line is reached. The physical capacity of the grid is therefore not static, but varies constantly with lower temperatures leading to higher capacities and vice versa. During cold or windy weather, when the line could actually handle more current while not exceeding its maximum allowed temperature, a part of its physically safe available capacity in fact remains unused. Close real-time monitoring of weather and line conditions can enable the application of real-time updating of line capacities, allowing for a more efficient use of the grid. This practice of constantly adapting line capacities to the current environmental conditions in order to maximize its utilization is called dynamic rating and is something TenneT is currently investigating.*

1.2.1 Definition of congestion in electricity grids

As discussed above, congestion in electricity grids is caused by scheduled flows that would exceed safe and reliable operation margins when actually implemented. Physical congestion (i.e. actual excess grid flows), however, should never be allowed to occur in the first place. In reality, such a situation would lead to the system operator taking emergency measures to avoid the excess flows from being placed upon the grid, as these would damage the equipment and possibly lead to blackouts. Congestion should therefore be understood, in line with definitions used throughout scientific literature (e.g. Kawann & Sakulin (2000) and Pérez-Arriaga & Olmos (2005)), as the situation in which a power line has reached its limits of safe operation, as a result of which “requests for deliveries (transactions) … cannot be physically implemented as requested” (Lesieutre & Eto, 2004, p. 59).

1.2.2 Causes and consequences of congestion

Congestion is caused by market participants wishing to carry out particular transaction patterns that are not in line with available line capacities. Kawann & Sakulin (2000) specify three causes for congestion: “(1) outages of generators, loads, or transmission facilities; (2) major changes in load flow situations due to increasing exports, imports and transits; or (3) loop flows” (p. 22). In order to avoid such situations, a system operator could ensure to have sufficient grid capacity available to cope with demand at all time. This approach has traditionally been a part of connection policy in the Netherlands, with the grid being adequate to meet transportation demands based on rated supplier and consumer capacities. Only if grid capacity was sufficient, new entrants would be connected. If not, the connection was delayed until after the grid was sufficiently reinforced. Because transmission system operator TenneT knew only the rated capacities for each connection, but did not know whether producers would actually *use* their connection at a particular moment (and to which extent). Rated capacities, rather than actual usage, were thus leading for grid planning. This created a potentially inefficient situation, because the grid needed to be capable to cope with all users transporting electricity at their rated capacity simultaneously, even though this was not always the case in reality. A producer, for instance, may not produce during one day under particular market conditions, but use its rated connection capacity in full the next day if conditions change and producing becomes profitable. Precise usage information was not known by TenneT in advance, however (Hommes, 2010).

As an alternative approach to having excess grid capacity available that is sufficient to cope with all demand/supply patterns, one could apply a form of congestion management. Although different congestion management systems are available (see section 3), the technical implications of all systems are the same: production is decreased inside an area upstream of congestion[5] and it is increased outside the area to cover demand (alternatively, under some schemes demand itself is reduced). With respect to ensuring safe and reliable operation, congestion management thus eliminates the need for grid reinforcements when additional capacity is connected to the grid. However, when taking other factors into account, such as short-term economic criteria, disadvantages of the application of congestion management also appear. Assuming that the market had originally determined the economically optimal pattern to dispatch generation units, the application of congestion management changes this dispatch order and forces a sub-optimal situation upon the system as a whole. Similarly, an environmentally sub-optimal outcome could be created if grid constraints in combination with a particular congestion management scheme result in readily available wind power being wasted because the grid does not allow for it to be transported.

The application of congestion management should therefore always be seen in the light of the desired system outcomes. Different schemes allow for different interests to be represented when “optimal outcomes” are determined. When deciding on an approach to deal with grid constraints, one needs to be aware of the desired system outcomes that a particular approach should lead to.

1.2.3 Congestion in the Netherlands

The causes for congestion described above in section 1.2.2 are short-term causes for occasional congestion. Congestion can, however, also have a more structural nature if grid capacity is insufficiently enhanced when new capacity is connected. Currently, a variety of market players is planning to construct new generation capacity in the Netherlands. 8 GW is already under construction (van der Lee, 2010a) whereas in total 30 GW is planned – twice the existing capacity (Persson, 2009). Because the vast increase in production capacity is not followed by any significant increase in national electricity demand, the Netherlands is expected to become a net exporter of electricity, rather than a net importer as it currently is. The electricity produced by these plants will thus need to be transported, which will increase flows on the Dutch transmission grid. For instance, electricity produced in the Second Maasvlakte area in the west of the country will make use of the

5 An 'area upstream of congestion' (or 'congested area') is an area with a surplus of production, but with insufficient grid capacity to transport this surplus to adjacent regions if so requested by the market.

Dutch transmission grid before flowing to Germany, Belgium, or even Norway using an interconnector (the BritNed cable, connecting the British and Dutch grids, is connected to the Netherlands at the Second Maasvlakte). Because the aforementioned new connection policy will also apply to these new plants – which allows these producers immediate access to the grid once the construction of their plants is completed – this will create major congestion problems for at least several years according to Van der Lee (2010a) and Hakvoort et al. (2009), as the expansion of transmission grid capacity cannot keep up with this increase.

The following sections will elaborate on the approach currently taken by the Ministry of Economic Affairs, Agriculture, and Innovation (also referred to as "the Ministry") to deal with the expected transmission system constraints (section 1.3) and the development of congestion on the Dutch transmission grid in the longer term (section 1.4).

1.3 Current congestion management approach in the Netherlands

Anticipating an increase of congestion on the Dutch transmission grid as a result of its new connection policy and the large amounts of production capacity planned to be constructed, led the Ministry of Economic Affairs to investigate the options available to deal with this congestion. Eventually, the Minister decided that the *basic system redispatch method* (see Appendix B.1.3) was to be implemented as a solution for the expected grid congestion. Section 1.3.1 will elaborate on the process that eventually resulted in this decision, while section 1.3.2 will subsequently discuss the disadvantages and negative long-term consequences of the method.

1.3.1 Decision

Commissioned by the Ministry, D-Cision and The Brattle Group (Hakvoort et al., 2009) analyzed the congestion management options for the Netherlands. They found system redispatch (with costs borne by generators), market redispatch, and a hybrid model –a combination of both the former– to be appropriate congestion management methods, though they recommended to implement the hybrid redispatch method[6]. Despite their work, the Ministry eventually decided to remain with basic system redispatch, with congestion costs to be borne by TenneT. In the view of the Ministry it turned out to be against European legislation to pass on the cost of congestion management to generators in a specific congestion area (van der Lee, 2010b). Although the legal staff of the Ministry changed its opinion after having carefully reviewed European legislation, system redispatch with costs borne by the TSO remains the status quo option for implementation because the opinion of the Dutch Senate was that European laws were breached if another option was implemented (Energie$^+$, 2010). Basic system redispatch, with costs borne by the TSO, will thus be implemented in the Netherlands and is a given reality for the near future.

1.3.2 Drawbacks

Although system redispatch can be an effective method for alleviating congestion, it has serious disadvantages which especially present themselves in the long term. Used as an occasional measure to manage non-structural congestion, it is an efficient measure that does not distort the electricity market (Pérez-Arriaga & Olmos, 2005). As a structural method, however, system redispatch has the serious drawback of creating a perverse incentive for generators that enables them to earn money if they contribute to *creating* congestion under certain conditions. This can, for instance, be done by delaying the decommissioning of obsolete plants in congestion areas or by even investing in new capacity in an area that is already congested (Hakvoort et al., 2009). The incentives created by the method are primarily aimed at the TSO. Because the scheme allocates all congestion costs to the TSO, it provides TenneT with a stimulus to increase grid capacity as it can prevent itself from having to bear these costs by increasing grid capacity to efficient levels. Congestion would thus, in the ideal situation, be of a temporary nature only, with network expansions providing a more

6 One must note that the scope of Hakvoort et al. (2009) was limited to identifying the congestion management methods that were quickly implementable. It did thus not consider all methods available. Also, closely related issues such as connection policy and network planning fell outside its scope.

structural solution by eliminating congestion altogether (insofar as congestion costs exceed the cost of reinforcing the grid).

This view is in line with the approach taken by the Ministry, which considers congestion management to be merely a temporary solution which can be applied until network reinforcements displace the need for congestion management altogether (van der Neut Kolfschoten, 2008). However, due to transport infrastructure taking longer to construct than generation capacity, it may lead to a situation in which TenneT simply cannot keep up with its reinforcements. Congestion costs could become very high if the method is applied "combined with a policy of connecting all generators without waiting for network reinforcements" (Hakvoort et al., 2009, p.37) – which is currently the case in the Netherlands. This situation is aggravated by the current regulatory framework governing the recovery of infrastructural investment costs by the TenneT. Only if an investment is considered to be efficient by the regulatory authority (Office of Energy Regulation, Dutch: Energiekamer) a network company is allowed to pass these costs on to customers. If grid capacity is pro-actively increased because an increase of generation capacity is expected, but this capacity eventually turns out not to be constructed after all, the network company may not raise its tariffs because the line is not utilized and therefore not considered to be efficient. Hakvoort et al. (2009) argue that this will almost always lead to a period of congestion, because decisions to reinforce the network will not be made unless there is sufficient certainty that the new capacity will actually be used. Due to the time it takes to reinforce the network versus the construction of generation capacity, this will inevitably lead to (temporary) congestion.

Another issue inherent to the decision to use system redispatch poses the question who will bear the resulting congestion costs. As discussed before, it will not be possible for TenneT to transfer congestion costs to those who actually contribute to congestion, i.e. the generators in a congested area[7]. Congestion costs could be transferred to all generators nation-wide, borne by TenneT itself, or socialized in transport tariffs. Under the latter option this cost would be passed on to consumers entirely, because producers currently do not pay for transportation of electricity in the Netherlands[8]. This would create a somewhat peculiar situation, however, where the grid costs created by a generator that solely produces electricity for exporting purposes is passed on to domestic consumers. As of today, this question with respect to cost distribution remains unanswered, yet these costs will almost certainly rise once congestion starts to seriously increase when new capacity becomes available.

1.4 Structural application of congestion management

As discussed above, the Ministry of Economic Affairs considers congestion on the transmission grid to be of a temporary nature, to be resolved by network reinforcements in the longer term, and thus views the role of congestion management as such. It considers the electricity system as a 'copper plate' where producers and consumers can inject and withdraw electricity from, without regard of their geographical locations (Leuthold et al., 2008). The application of uniform pricing is inherent to this view, which precludes the existence of price variations due to geographical differences. This approach allows for market parties to trade electricity freely and it lies at the basis of a well-functioning electricity market in the perspective of the Ministry (Brunekreeft et al., 2005; NMa, 2009). Note that an important drawback of the application of uniform pricing is that it does in itself not provide signals to the market for efficient geographical siting of new capacity (Leuthold et al., 2008).

For efficient functioning of the market, the Ministry further deems it necessary that new entrants can be directly connected to the grid, without the need for the necessary grid reinforcements to be completed. To illustrate this: the benefits of allowing new entrants to be connected to the grid before the necessary reinforcements have been completed are expected to yield an annual societal

7 A 'congested area' (or 'congestion area') is an area with a surplus of electricity production, where grid capacity is insufficient to transport this surplus to adjacent regions as requested by market parties.

8 Electricity producers in the Netherlands only pay a periodical connection charge, independent of electricity volumes actually transported (van der Neut Kolfschoten, 2008).

benefit of € 450 to € 750 million (Minister of Economic Affairs, 2009). The 'copper plate'-approach has a downside, however, in the sense that no incentives exist for production and consumption to be located efficiently (in a geographical sense, from a grid perspective), because all costs and benefits resulting from locational choices of power plants and large consumers are socialized via the transport tariffs that are charged to network users. The assumption of the approach is that the benefits from enhanced competitiveness exceed the costs that result from inefficient use of the grid.

TenneT has indicated that reinforcements of the transmission grid will become increasingly difficult to realize in the future and, in fact, expects to be unable to keep up with transportation demand if currently planned production capacity is indeed realized. Given the desired policy of connecting new entrants before grid capacity is reinforced, the inevitable result is an increase in congestion and, thus, an increasing need to fall back to the current practice of system redispatch. Even though this system creates (strong) incentives for the TSO to invest in transmission capacity if it is to bear the costs of congestion, the required grid reinforcements cannot always be made. The reasons for this are threefold and will be elaborated below.

- **Difficulties obtaining financial means for network investments**

  Transmission infrastructure is very capital intensive and sufficient monetary funds need to be acquired by TenneT in order to make the necessary investments. Currently, these funds are raised from financial markets (70%) and financed by TenneT's own capital (30%). Because the need for new transmission capacity is so extensive, TenneT expects to be unable to raise sufficient funds for all required investments in the coming years. This is worsened by the current economic situation, which leads to increased difficulties for attracting capital. In addition, TenneT will need to depreciate its current assets (i.e. the parts of the grid it owns) in an accelerated pace, the reasons for and consequences of which are briefly explained hereafter. With regard to investments in transmission grid infrastructure, TenneT can only pass on to customers those capital costs of the grid that are considered efficient by the Office of Energy Regulation. Each new investment knows a depreciation period over which capital costs can be recovered, which is fixed by the Dutch competition authority NMa. Originally (i.e. in the year 2000) NMa allowed TenneT to consider all of its existing (pre-2001) assets to be 'efficient', and thus allowed the original depreciation periods to be maintained (NMa, 2009). This, however, is no longer the case due to a change of regulations, as a result of which TenneT now has to depreciate these assets in a shorter period of time. This regulatory change has not gone unnoticed by the capital markets and the increased regulatory uncertainty results in TenneT experiencing more difficulty to attract capital. (van der Lee, 2010c)

- **Uncertainty about investment and decommissioning plans of generators**

  As mentioned before, transmission infrastructure takes longer to develop than production capacity. Because TenneT does not know beforehand when and where new production capacity will be constructed, it will almost always lag behind with its infrastructural reinforcements. Also, market players generally do not disclose their plans for decommissioning to TenneT in advance (van der Lee, 2010a). This lack of insight in market developments makes it difficult for TenneT to anticipate future transmission demand and could lead to excess capacity –i.e. additional (societal) costs– or insufficient capacity –resulting in congestion and an economically suboptimal dispatch of power plants.

- **Regulatory barriers**

  The third, and in the long run most important reason for insufficient transmission capacity is the increasing difficulty to realize infrastructure projects due to regulatory barriers. TenneT expects not to be able to acquire construction permits for all necessary projects and it foresees an increase in the duration of the procedures to acquire such

> permits. According to Van der Lee (2010b) this is the result of increasing social resistance towards large scale transmission infrastructure projects which causes an inability to meet the entire demand for transmission capacity.

The inability to implement the required grid reinforcements seems to expose a discrepancy that appears to exist between, on the one hand, the approach towards congestion taken by the Ministry, and, on the other hand, the current state and development of reality envisioned by TenneT. TenneT expects congestion to become a structural problem in the Dutch transmission grid, which can no longer be completely resolved by transmission grid reinforcements, whereas this is precisely the core of the Ministry's approach for dealing with transmission constraints. Given the drawbacks of system redispatch described above, TenneT would like to have other options to deal with these constraints as congestion appears to become a structural problem. Any such method should allow for effective prioritization of renewable energy sources, as is desired by the Ministry, and should also be assessed in the light of European market integration which is a long-term goal of the Dutch government (Rijksoverheid, 2010).

1.5 Report outline

PART I

This report consists of three parts. Part I serves as an introduction to the study by introducing the research problem and research questions. The current chapter introduced the concepts of congestion and congestion management in the electricity sector, and presented the current situation in the Netherlands with respect to these concepts. The research problem that is dealt with by this study will be further elaborated in Chapter 2, which will also discuss the research approach taken during this study, specify its objectives, and present the research questions that were formulated in order to address the research problem. Chapter 3 presents an overview of the available congestion management methods and discusses their characteristics. It will also introduce the methods that will be evaluated during this study using a quantitative model, which is dealt with in Part II.

PART II

Part II of this report presents the results of the quantitative modeling study that was performed to expand the theoretic knowledge that was gained from literature, with a quantitative insight in the effects of application of congestion management in the specific case of the Netherlands. The model that was constructed as a part of this project is introduced in Chapter 4, which discusses the conceptualization of the Dutch electricity system and elaborates on the model specification process. Subsequently, Chapter 5 elaborates on the way in which the model was used. This includes presenting the scenarios that were constructed. The simulation results that were obtained using the model are presented in Chapter 6.

PART III

On the basis of the literature study and simulation results that were performed in the preceding chapters, Part III will discuss the implications of these results for the application of congestion management in the Netherlands. Chapter 7 analyzes the consequences that the simulation results presented in the previous chapter have for the debate on congestion management in the Netherlands. Subsequently, Chapter 8 will identify the criteria relevant for the application of these methods in the Netherlands, and subsequently apply these criteria to the methods in order to assess their suitability for the specific Dutch situation. Chapter 9 presents the main conclusions of this study and, also, provides the recommendations and new insights that were found during this study, which could serve as input for further research.

At the end of this report, succeeding Chapter 9, the author will reflect on the research approach, the research process, and the results that were obtained and interpreted.

2 Research problem

The Ministry of Economic Affairs has decided that congestion in the Dutch transmission grid should be managed by means of the system redispatch method, which at least for the near future will simply be reality for TenneT. Section 1 has shown, however, that a discrepancy exists between the perceived effectiveness of this approach taken by the Ministry and the future reality expected by TenneT. Because congestion will become a structural problem, instead of merely a temporary situation that is eventually solved by grid reinforcements, this study will provide a quantitative insight in the consequences of the application of basic system redispatch for the Dutch electricity sector. It will assess the effectiveness of the method and compare with a number of alternative congestion management methods, on the basis of which it aims to provide recommendations as to which method would be most appropriate for dealing with congestion in the Dutch power sector in the long term.

2.1 Research approach

Although it is not always politically desired, the functioning of any market relies upon the provision of correct signals that provide an incentive (i.e. the correct incentive) for efficient behavior by market participants. The underlying mechanism of markets to achieve this efficiency is the use of price signals. Basic economic theory tells that high prices indicate shortages or another imbalance resulting in excess demand, whereas low prices indicate a surplus and/or low demand. If the (political) choice is made to leave electricity production to the market, i.e. liberalize it, it is therefore necessary to regulate that market in a manner that does not suppress these signals for the market to function properly and to produce efficient outcomes.

Managing congestion using market-based methods allows capacity to be allocated to market parties in a transparent and efficient manner with prices reflecting the true value of transmission capacity, while simultaneously improving liquidity of electricity markets (Kristiansen, 2007b). It is argued that economic efficiency can be enhanced using a market-based congestion management approach, and it should therefore come as no surprise that there currently is a tendency towards such market-based systems for managing interconnection capacity between European markets (Brunekreeft et al., 2005; Kristiansen, 2007b). Market-based methods do not place the powers and responsibility to deal with congestion management in the hands of authorities that can single-handedly set prices for market participants and decide on the allocation of capacity. This simplifies ensuring, and potentially enhances, transparency and efficiency, as 'decisions' with respect to capacity allocation and prices are made implicitly[9] on the basis of market signals.

Application of European competition law

In this light it is also useful to note that "the European Court of Justice has ruled that the energy sector is within the scope of the competition rules" (Copenhagen Economics, 2006, p. 3, quoted from Faull & Nikpay, 1999, p. 689) and that this inclusion also applies to system operators (Copenhagen Economics, 2006). They are thus bound to the same competition rules as "regular" undertakings. With respect to (facilitating) cross-border electricity transport this means that they may not abuse their market power and need to treat all market parties equally and in a non-discriminatory manner.

Furthermore, a market-based congestion management method is currently being implemented to manage congestion in Sweden internally. The country has been a part of the integrated Nordic electricity market since 1996, which applies market splitting to manage congestion between the national systems of the countries participating in the common market (Norway, Sweden, Finland, and Denmark). Congestion *inside* Sweden was managed by means of counter trade (Svenska Kraftnät, 2007). Following Norway and Denmark, which already apply different prices in distinct

9 Mind the textual context in which the term 'implicitly' is applied here; it does not refer to the concepts of implicit and explicit auctions in congestion management, but refers to the word 'decisions' (on prices and allocation).

geographical areas if market forces cause a deviation from the system price (Houmøller, 2010), Sweden has now decided to introduce market splitting internally as well.

The current tendency towards market-based congestion management methods in Europe shows, or at the very least indicates the possibility that market-based congestion management methods lead to more efficient outcomes than the more traditional non-market based approaches. Also, the goals set by TenneT and the Dutch government with respect to enhancing the integration of European electricity markets give rise to the appropriateness of using such methods to manage congestion internally, instead of the currently applied method of system redispatch.

Note that several methods – e.g. system redispatch, counter trading – use some form of market mechanism to alleviate congestion, but are nevertheless not classified as a *market-based congestion management method*. Throughout this study the term *market-based* will only be applied to systems where the market itself solves congestion through efficient pricing, unlike methods where the TSO actively trades power to solve congestion. Further note that being classified as a market-based method does not preclude the TSO from playing a *facilitating* role, for instance by running a spot market where market participants can trade electricity.

2.2 Research objective

Above, the term effectiveness was used (in the light of evaluating different methods) which is susceptible for interpretation. More specifically, this study deals with evaluating a number of congestion management methods in order to assess their suitability for application in the Netherlands, given the nature of congestion, the (societal) goals that are pursued by applying congestion management, and given the specifics of the Dutch electricity sector. At the basis of this analysis lies determining the particular outcomes that can be expected by the application of different methods, with respect to allocation of congestion costs, incentives provided to generators for alleviating congestion (or, for instance, find out whether a perverse incentive to contribute to congestion exists), and the potential to abuse the scheme under situations of market power. In this light it will answer the important question of who benefits or experiences a disadvantage from congestion, under what circumstances, in which region, and whether this is appropriate, acceptable, and/or desired.

This research approach enables the identification of a suitable method (or methods) that allows TenneT to structurally deal with grid congestion, taking into account factors such as costs and the distribution thereof, provision of incentives for efficient siting of facilities, promotion of renewable energy sources, opportunities for the scheme to be gamed and how to counter this. On the basis of these results this study will discuss what method would be most appropriate to implement and what specific characteristics it must include when applied in the Netherlands. This encompasses an analysis of the design requirements of a congestion management system, which is particularly important if one considers the fact that the Ministry has proven to be hesitant to implement congestion management systems that radically change the approach taken towards the electricity system and market. Any scheme under which various electricity prices would exist within the Netherlands, for instance, has to date been dismissed for political reasons.

2.3 Research questions

This study will deal with the research problem described above by answering the following research question, which is broken down into various sub-questions for the sake of clarity and to accommodate the process of its answering.

> *"What congestion management method is most appropriate for effectively managing transmission grid congestion in the Netherlands, while optimizing overall (economic) system efficiency within the constraints that follow from the objectives set for the Dutch power sector by the Ministry of Economic Affairs, Agriculture, and Innovation?"*

1. What are the drawbacks of the basic system redispatch method that is currently applied to manage congestion?

2. What market-based congestion management methods are available and what is their position in within the overall set of methods?
3. What effects are these methods expected to have in the Netherlands?
   - What region(s) are sensitive for congestion?
   - What is the cost resulting from the application of such methods and how are these distributed?
   - Which parties benefit from congestion and which experience a disadvantage?
   - Is this allocation of congestion costs appropriate, acceptable, and desired?
   - Does the use of (some of) these methods lead to opportunities for the abuse of market power?
4. What specific characteristics should a method possess for application in the Netherlands?
5. What method is most appropriate for implementation in the Netherlands?

Section 2.4 below discusses the research methods that will be used to answer these questions. Note that they are dealt with insofar as they fall within the scope of this study, which is delineated in section 2.5 below.

2.4 Research methods

Various research methods were applied to answer the different research (sub-)questions that were presented in section 2.3. The nature of these methods divides the project into three somewhat distinct parts, which is indicated by Table 1. Part I, which deals with research questions 1 and 2, entails a literature study that introduces congestion management, particularly discussing the current Dutch congestion management approach, and organizes the rich congestion management terminology that was found to be present in existing scientific literature. Part II has a more quantitative nature and includes the construction of a quantitative model to allow for simulating the application of congestion management methods in the Netherlands, to enable a comparison of the outcomes of applying different approaches using multi-criteria decision analysis (MCDA). On the basis of the results from the former parts, Part III aims to come up with a design of a congestion management method deemed appropriate to manage congestion in the Netherlands. It will combine the technical, institutional, and process elements that play a role and make use of various tools such as stakeholder analysis and expert interviews, to come up with a detailed design of both a feasible congestion management approach as well as a road map to its actual implementation.

	Research question	**Research method**
Part I	(1)	Literature review
	(2)	Literature review
Part II	(3)	Quantitative model
Part III	(4)	Stakeholder analysis; institutional design
	(5)	MCDA

Table 1: Research methods

2.5 Scope

This study focuses primarily on the (quantitative) evaluation of a number of market-based congestion management methods (see section 3.2), and, subsequently, the design and implementation of a system considered suitable for the Netherlands. Although the application of a congestion management method is actually only an aspect of an overall approach to deal with transmission constraints, which also includes aspects such as connection policy and infrastructure strategy, the scope of this study is deliberately restricted to evaluating congestion management methods. Given the limited time that is available for this study, this delineation allows to conduct a thorough evaluation of the congestion management element as an aspect of the broader issue of dealing with transmission constraints.

One must note that the proposed model will bear some limitations that are inherent to its design. The model will comprise static model, which is able to calculate market and system outcomes for the scenario conditions to which it is being exposed during a particular run. After the outcomes have been documented, it is run again under different conditions. It is thus not run over a longer period of time and will not simulate the actual occurrences of congestion (a model for this purpose is currently under development within TenneT).

Furthermore, network safety and the reliability of the electricity supply are not explicitly considered during this study. These notions are considered of the utmost importance and are thus treated as such during every aspect of this study. All congestion management methods and other measures discussed in this document should be interpreted as to adhere to the constraints that follow from transmission grid safety and reliability requirements.

Please refer to the research proposal written prior to this study (van Blijswijk, 2010) for a more elaborate discussion on the precise delineation of the research problem considered in this study (section 2.3), the research methods used to answer the questions above (sections 3.1 – 3.5), and the internal cohesion of this study (section 5.1). This proposal also discusses the scientific and social relevance of this study (sections 2.4 and 2.5, respectively).

3 Evaluating congestion management methods

In section 1.2.1, congestion was defined as a situation in which the pattern of transactions as desired by market players cannot be carried out due to transmission constraints. Such a situation can be solved by applying congestion management or by using other measures, such as increasing transmission capacity by reinforcing the grid. Because congestion can be dealt with using a variety of measures and congestion management methods exist in many different forms, with similar methods being implemented in different forms, a rich terminology is used throughout literature. Even within the family of congestion management methods confusion may arise, as different terms are used to indicate similar methods, or vice versa. Although practically all congestion management methods yield a similar result in the sense that they lead to a decrease in production inside congestion areas and an increase outside these areas, there is a wide variety in means to achieve this outcome. Different methods use different criteria to determine which plants are ramped up and down, in what manner congestion imposes a cost to society, how the resulting costs are distributed, and (thus) who benefits from congestion and who experiences a disadvantage.

Section 3.1 provides a structured overview of congestion management methods by categorizing them on the basis of their main design variables, thus providing a clear picture of the spectrum of available options. Apart from merely providing an overview, it will also discuss the methods and their characteristics. Because it is based on existing literature and this knowledge is thus already available, detailed information will be provided mainly in the form of references to the sources where this information can be found. Section 3.2 introduces the four market-based methods that will be further evaluated in this study using a quantitative model (section 4) and will discuss why these were chosen. Finally, section 3.3 presents the key performance indicators that will be used to evaluate the methods in 3.2 and to allow for a comparison of their outcomes.

3.1 Overview of methods to deal with grid congestion

Table 2 provides a structured overview of the various options for congestion management that were found in existing literature. This overview was created on the basis of the rich terminology that is used throughout (scientific) literature, which contains synonyms indicating the same (or very similar) method, but also homonyms referring to different methods using the same name. A full overview of the terminology found in existing literature and the subsequent categorization effort can be found in Appendix A. A brief explanation for these methods is provided in Appendix B.

Congestion management methods	
Active TSO intervention:	
Transmission capacity adjustments	Artificial capacity adjustments Capacity expansion
Direct capacity allocation	Traders solve congestion • Market agent approach TSO solves congestion • Allocation of physical rights: priority list • Allocation of physical rights: proportional • Dispatching least-cost generators on the basis of complete information • Geographic differentiation in transmission use-of-system charges • Line flow splitting[10] • Reserve price auction • Retention

10 Using the line flow splitting method electricity transmission tariffs are related to the efficiency of grid use by consumers. However, physical congestion is solved by the system operator by redispatching generators (Kawann & Sakulin, 2000).

Redispatch using market-based criteria	Full TSO coordination • Basic system redispatch • Co-ordinated Re-dispatching Cost + • Counter trade • Hybrid redispatch • System redispatch with cost pass-through to generators Trader involvement/responsibility • Market redispatch
Market coordination:	
Auctioning of transmission rights	Coordinated explicit auction (e.g. flowgate or point-to-point rights system)
	Decentralized explicit auction (e.g. auctions of multi-lateral transmission rights; cross-border auction trading)
Price differentiation (to geographic area)	Coordinated implicit auction • APX-based method • Market splitting • Nodal pricing • Zonal pricing Decentralized implicit auction • Market coupling
Demand-side measures:	
Congestion solved by consumer reaction to situation	Demand-side bidding Transmission loading relief

Table 2: Structured overview of congestion management methods

As was briefly discussed in section 2.5, one must note that applying a method to manage congestion is actually just one approach for coping with the constraints that exist within a transmission network. As an alternative to congestion *management* a TSO (or another responsible authority) could apply other measures that result in electricity flows to remain within safe and reliable operating margins. With respect to such measures, Table 2 includes transmission system expansions and demand-side measures. In addition, the former Dutch connection policy in which new entrants were not automatically connected to the grid directly, is also *de facto* an example in which transmission rights are only allocated to existing players, but not to new entrants. On the basis of the definition provided in section 1.2.1, congestion management should thus be understood as a measure that is applied in the short run when scheduled flows, after calculating their effects on the grid, would result in a physically unfeasible transmission flow pattern. In this situation congestion can no longer be avoided, and as a result it must be *managed*.

3.2 Market-based congestion management methods

Despite the overall tendency in Europe to apply market-based methods to manage congestion, as was discussed in section 2.1, the Dutch government decided to implement the system redispatch method, which is not considered a market-based mechanism in the definition[11] of Table 2. The outcomes from this approach may prove to be (very) different from those that may have been obtained when a market-based method would have been applied. To evaluate whether this is the case, this study will compare a number of market-based congestion management alternatives (see below) to the current approach of basic system redispatch. More specifically, it aims to determine whether the outcomes of important indicators –these are further elaborated in section 3.3– such as congestion costs, the distribution therefore, opportunities to exert market power, and the resulting investment incentives would be different under a market-based method.

11 This distinction is further elaborated in Appendix B.1.

This study focuses on three market-based congestion management methods, which make use of a geographical price differentiation mechanism to allocate scarce transmission capacity. These methods are compared to basic system redispatch, which makes use of separate 'congestion power markets' to achieve the redispatch volume required to bring transmission flows within limits:

- Market splitting
- Market coupling
- APX-based method developed by TenneT
- Basic system redispatch

This is not an exhaustive evaluation of the market-based methods as provided by Table 2. There is a number of reasons for including these, and excluding other (decentralized explicit auction, nodal pricing, zonal pricing) methods, which will be elaborated below.

- **Decentralized explicit auction**

  The auctions of cross-border transmission capacity between European countries – which together form one electricity system – are an example of decentralized explicit auctioning. Interconnection capacity between two countries (or even individual power lines) is explicitly auctioned by the involved relevant TSOs and this is done separately from other interconnections. These decentralized auctions lead to inefficiencies in transmission system usage, which can be worsened with the increasing share of intermittent sources (Brunekreeft et al., 2005). Although this method could in principle be applied within the Netherlands (transmission capacity between various regions could be auctioned independently from one another) there is no reason to do so, as the country is already under the authority of one TSO.

- **Nodal pricing**

  Applying nodal pricing requires sufficiently large markets to exist within the distinct areas in order for them to be sufficiently liquid (Ehrenmann & Smeers, 2005). Market splitting addresses the problem of illiquid nodal markets by clearing all nodes in a particular area together, assuming them to be one, integrated market. Only if transmission constraints prohibit the resulting flows from being physically implemented, the market is split in two or more nodes with varying prices reflecting transmission scarcity. Furthermore, true nodal pricing would result in many different electricity prices throughout the Netherlands. As dividing the country into a much smaller number of price regions is already controversial in the Netherlands according to Hommes (2010), it is deemed more relevant to consider methods that only create a small number of price regions, when discussing the issue of price differentiation in the first place.

- **Zonal pricing**

  The phrase 'zonal pricing' can be interpreted as referring to different systems. This is addressed in Appendix A.4, which includes the definition of zonal pricing as used in this study. As a separate method zonal pricing is not included in this study for similar reasons as nodal pricing (though the lack-of-liquidity problem is smaller as the geographic area of the zones is larger). However, all methods that are evaluated apply some form of zonal pricing in some circumstances. The coupled markets under market coupling, the separated price regions under market splitting, and the congestion regions distinguished by APX-based method, actually all make use of price zones.

3.3 Evaluation of congestion management methods: KPIs

The market-based congestion management methods that are considered in this study are evaluated by means of a quantitative simulation model, which will be introduced hereafter in Chapter 4. This model enables an objective comparison between the different methods by assessing their performance on the basis of four (quantifiable) key performance indicators (KPIs). These KPIs correspond with the factors of interest that were deemed central to the objectives of this study and which were made explicit under research sub-question 3 in section 2.2.

Table 3 presents an overview of the KPIs, and includes a definition and measurement unit for each. Please refer to section 4.4.4 for more information on the specifics regarding their inclusion in the simulation model.

KPI		Defined as:	Unit:	Scale
1	Extent of Congestion Index (ECI)	Qualitative and quantitative component; qualitative: under which scenario-conditions? / quantitative: proportion of congested capacity	% (ECI)	Ratio
2	Congestion cost - Consumers - Producers - TSO	Difference between surplus under application of congestion management mechanism and hypothetical situation with infinite transport capacities.	Δ€ (surplus difference)	Interval
	Social surplus *- Consumer* *- Producer* *- TSO* *- Total social welfare*	 *Surface between (accepted) bid curve and MCP* *Surface between MCP and (accepted) offer curve* *Congestion rent* *Sum of the surpluses above*	*€ (net surplus)*	*Ratio*
3	Incentives	Qualitative assessment comparing resulting incentives to desired incentives	Qualitatively scored scale	Ordinal
4	Residual Supply Index[12] (RSI)	Share of the load that can be supplied by all generators other than the largest	% (RSI)	Ratio

Table 3: Key performance indicators

3.3.1 Region congestion sensitivity

One of the objectives of this study is to determine how sensitive regions are for congestion. Although this may not seem directly related to the assessment of congestion management methods, which after all is the central topic of the quantitative modeling study, it is important to realize that the extent of congestion is not only an indication of the (perceived) problem, but may also influence the conclusions that are drawn from the other indicator scores. If congestion is expected to be of an incidental nature only, one may attach less weight to the risk of market power abuse or the existence of perverse incentives, compared to a situation in which congestion is structurally present. For instance, as was discussed in section 1.3.2, basic system redispatch carries the risk of creating large congestion costs which need to be borne by the TSO and, eventually, the consumer. If it needs to be applied on an incidental basis only, some of the advantages (e.g. short-term efficient and relatively easily implementable (Hakvoort et al., 2009)) may outweigh the drawbacks, whereas when it needs to be applied on a structural basis, this may no longer be the case. Determining the extent of congestion is therefore a highly relevant element of evaluating and comparing different congestion management methods.

Determining the extent of congestion

Although it is rather easy to determine whether a region is congested or not (which is the case when scheduled transmission flows would exceed physical capacity of the power lines connecting that region when implemented) a definition needs to be used to measure the *extent* of congestion. Basically one can take two approaches when calculating a value that represents the extent of congestion, either on the basis of redispatched generation capacity or on the basis of transmission capacity shortage. The former approach defines the extent of congestion using data on the (share of) demand that cannot be fulfilled because of congestion (and therefore needs to be dispatched

12 Alternatively, if the model were to be non-static and run over time, the Pivotal Supplier Index could be used to calculate the extent to which there are suppliers that are essential ("pivotal") in meeting demand; see 3.3.4.

within that region itself[13]) whereas the latter is based upon the amount of power by which a particular grid segment would be exceeded if the scheduled flows were to be implemented.

In a simple power system, such as depicted in Figure 1(a) (top), the values calculated under both definitions would be equal. In (a) the extent of congestion is 50 MW, both in terms of the excess scheduled flows as well as the required redispatch volume. However, when electric power uses multiple paths to reach its destination, a discrepancy in the values of both indicators may arise under otherwise equal conditions. A situation as in Figure 1(b) (bottom) would result in a power line that is congested by 50 MW (i.e. the scheduled flow exceeds its capacity by 50 MW), but 100 MW would need to be redispatched in order for the power flow over this line to stay below 50 MW. Both indicators may thus provide different information on the extent of congestion (required redispatch capacity vs required transmission capacity expansion), and it is therefore important to use an indicator that matches the dimension of congestion that is relevant for this study.

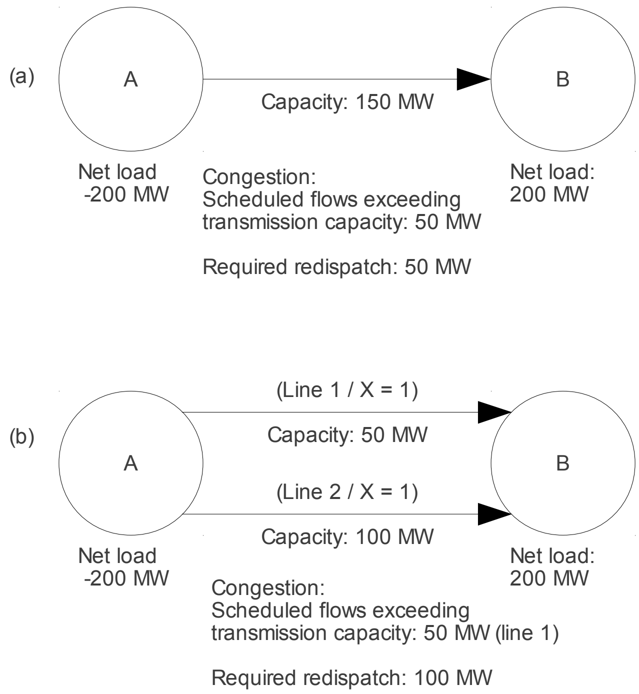


Figure 1: Measuring the extent of congestion: two definitions

All congestion management methods that are evaluated during this study require an Available Transfer Capacity (ATC) value to be calculated for the total possible power transfer between congestion regions. It therefore makes no difference which power line is actually responsible for the congestion, as long as the aggregated ATC between two congested zones can be accurately determined. Therefore, the second definition (transmission capacity shortage) has no meaning when applying any of the congestion management methods, because it does not provide any information on the available capacity that can be used by market players to trade electric power. Congestion will therefore be measured on the basis of the volume that needs to be redispatched from the upstream to the downstream congestion zone.

Because the same absolute amount of congestion would have a much larger impact in a region with limited production capacity and much internal demand, compared to a region with a large amount of production units but low internal demand, it should be interpreted in the light of a region's generation capacity and load. 1,000 MW of constrained power would (assuming equally shaped supply curves) have a much larger impact in a region with only 1,500 MW of excess generation capacity, than in a region with 5,000 MW of excess capacity. Therefore, the extent of congestion is measured by the Extent of Congestion Index (ECI), which is defined as the congested capacity (in MW) as a share of a region's excess (i.e. initially non-dispatched) capacity:

$$ECI = \frac{P_{constrained\ on}}{P_{not\ dispatched}} \qquad \text{(Equation 3.1)}$$

Note that 'Constrained capacity' can refer to both imports and exports which cannot be implemented as desired by the market (i.e. the transaction pattern is technically unfeasible). Thus, in case a region is considered congested because its exports cannot be (fully) implemented, the

13 Or the demand is withdrawn (e.g. using DSM or an increased electricity price – applicable under some congestion management methods).

share of 'constrained capacity' is determined by the *constrained off* capacity[14]. Import congestion, on the other hand, is defined by the capacity that was initially meant to be imported, but needs to be dispatched within this region itself as a result of congestion, i.e. the *constrained on* capacity[15].

Definition of congestion sensitivity

Region congestion sensitivity can be analyzed by making a simulation model subject to a wide variety of scenarios and evaluating the number of occurrences and the gravity of congestion. A region is considered 'congestion sensitive' in this study if it is more vulnerable to congestion under different scenario conditions than others. This is measured by aggregating the outcomes with respect to the extent of congestion per region under all scenarios.

The 'Region congestion sensitivity' KPI will eventually result in a table which shows the (relative) extent of congestion under all scenarios that are tested for. These values are subsequently interpreted and result in knowledge about the extent of the problem and the regions that are prone to congestion. Note that the physical characteristics of electricity may potentially have an important implication for this indicator, in the sense that congestion may also arise when transmission capacity between two adjoining areas appears to be sufficient, but “third-party flows” place a load on this segment of the grid as well. This is further discussed in section 4.4.4.

3.3.2 Congestion cost and social surplus

Although the outcome for individual players may be different, congestion creates net costs for society because of the inability of the system as a whole to achieve least-cost dispatch. When the market functions efficiently and an optimal dispatch of generation units is achieved on paper, transmission constraints may render such a transaction pattern unfeasible in reality. Any other dispatch arrangement that results from applying congestion management will by definition cause congestion costs under the definition used in Table 3, because if this “new” arrangement was more efficient it would have been implemented by the market in the first place. In short: congestion decreases social welfare, because rising congestion costs decrease social surplus. As these indicators are interrelated, they are discussed simultaneously.

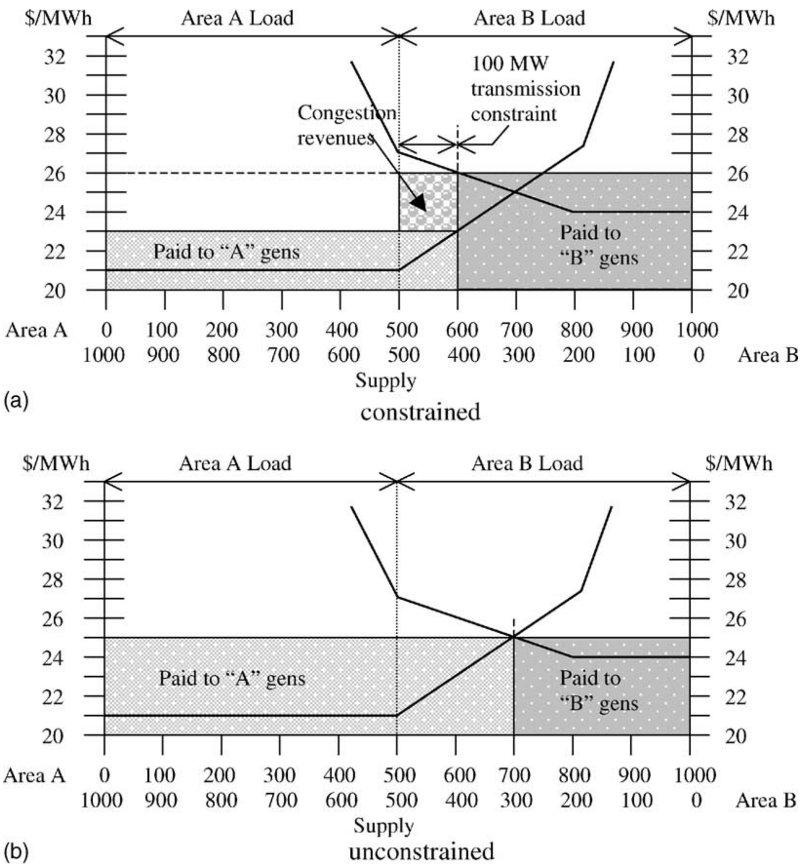


Figure 2: Decreased consumer welfare after eliminating congestion (source: Lesieutre & Eto, 2004)

Total social welfare: an incomplete indicator

It is important to realize, however, that although

14 Production capacity located in an upstream congestion region (with excess capacity) that was intended to produce electricity on the basis of the market outcome, but cannot do so due to transmission constraints.

15 This is the capacity that was originally not dispatched on the basis of the market outcome, but now needs to be dispatched after all to compensate for the *constrained off* capacity.

congestion leads to lower social welfare in theory, it by no means affects all players in the same fashion. In fact, a situation may even occur where some market players benefit from congestion at the expense of others. Such asymmetric allocation can be either inherent to the system (e.g. market splitting, where consumers in areas with excess production capacity experience lower prices than consumers in congested areas with a shortage of (cheap) capacity) or the result of gaming (e.g. when generators bid below their true variable costs under the basic system redispatch method).

Lesieutre & Eto (2004) provide an example of a congestion management measure that improves social welfare, but would likely be considered socially undesired in reality. It is included here because it clearly illustrates the relevance of including the distribution of congestion costs and benefits (i.e. welfare gains and losses), rather than merely considering changes in total social welfare. In the example, which is illustrated in Figure 2, transmission capacity between two regions is increased because transmission constraints cause dispatch to be sub-optimal. Both areas A and B have an (inelastic) demand of 500 MW. Figure 2(a) shows the accepted supply offers when a transmission constraint of 100 MW applies (600 MW by generators in A and 400 MW in B), whereas Figure 2(b) shows the same situation but without any transmission constraints (700 MW in A and 300 MW in B).

Albeit congestion is eliminated in (b) and total social welfare (TSW) increases by $150 as a result of increased transmission capacity (see Table 4), the average electricity price in the combined region also increases, thereby causing a loss of consumer surplus of $500[16]. In this example this is caused by a difference in the steepness of the marginal supply curves in both regions. Producers in A benefit from the capacity enhancement: their surplus increases by $1,300, both from charging a higher system price and by selling electricity at the expense of (more expensive) generators in B, which see their surplus drop by $350. On the whole, the producers benefit from the capacity expansion, by $950, of which $800 comes at the expense of the other parties and only $150 is a true increase in total social benefit.

Stakeholder	**Surplus in (a)**	**Surplus in (b)**
Producers A	1100	2400
Producers B	600	250
Consumers	1500	1000
TSO	300	0
Total social welfare	3500	3650

Table 4: Surpluses in Figure 2

This example shows that given the potentially disproportional distribution of congestion costs, one cannot suffice evaluating congestion management methods by merely determining the welfare changes that result from achieving a particular dispatch pattern. The distribution of congestion costs that is the outcome of applying a particular measure may not be socially acceptable, even if it increases total social welfare. This is also related to the investment incentives that follow from such distribution, which is discussed in section 3.3.3. Note that in this example the cost of increasing transmission capacity was ignored. If areas A and B were regions within the Netherlands, this cost would eventually be transferred to consumers under current transmission tariff regulations, thereby making them even worse off.

Three surpluses

Given the shortcomings of total social welfare as an indicator, which was illustrated by the example in the previous sub-section, this study distinguishes three components of total social welfare. This allows for a more detailed evaluation than TSW alone. The components are listed below.

- Consumer surplus
- Producer surplus
- TSO surplus
    - National congestion
    - International congestion

16 Because Figure 2 does not provide a demand curve the absolute consumer surplus cannot be determined. It is, however, possible to determine the loss of surplus by calculating the cost increase that is involved.

The consumer and producer surpluses are determined by the sum of the differences between the market clearing price (MCP) and the heights of the accepted bids and offers, multiplied by the traded volume. The indicators congestion cost and social surplus can be scored on an interval and ratio scale respectively. Note that a distinction is made between internal congestion (within the Netherlands) and congestion that arises on the interconnections. During this study it is assumed that the latter are split between both TSOs involved in the trade, which implies that TenneT receives half of the congestion rents. For the sake of simplicity, the German part of the grid owned by TenneT's wholly-owned subsidiary formerly known as Transpower, is considered as a separate foreign entity as well.

3.3.3 Incentives

The distribution of congestion costs (and benefits) over society, that was discussed in section 3.3.2, is not only important in terms of social acceptability, but also because it may create (dis)incentives to invest in particular areas – either as a generator or as a (usually large industrial) consumer. A producer that benefits financially from being located in a congestion area is unlikely to invest in new production capacity within this area if this would decrease its revenues. Also, an industrial consumer might invest in an energy-intensive factory inside a congestion area if the cost of this congestion is not borne by consumers within this area or even the factory itself.

Although the 'optimal' incentive is difficult to determine as different types of market players –or even individual stakeholders– have opposing interests, a market signal that triggers a Pareto-optimal improvement could be considered to be desired from a societal perspective at the very least. This means that the incentive that is provided makes no single player worse off, while providing a benefit to some (or all).

Congestion management method application outcomes are assessed by evaluating whether the distribution of congestion costs (i.e. relative change of surpluses) create the (investment) incentives that are desired from a societal perspective. This will be done by analyzing the distribution of congestion costs and qualitatively determining what market response can be expected on the basis of this signal. The indicator score on this criterion is then determined on an ordinal scale.

3.3.4 Residual Supply Index

As was discussed by Van Blijswijk (2010), existing literature generally deals with congestion management methods from a theoretic perspective, assuming perfect competition and not taking into account the opportunities for market power to be exerted (e.g. Ehrenmann & Smeers (2005), Hakvoort et al. (2009), Leuthold et al. (2008), Pérez-Arriaga & Olmos (2005)), or focuses on interconnections between European electricity systems (e.g. Glachant & Pignon (2005), Kristiansen (2004); Kristiansen (2007b); Lise et al. (2008)). One of the key contributions of this study will be to provide an insight in the opportunities for generators in the Netherlands to exert market power, with the aim to increase profits at the expense of consumers, the TSO, or other producers. Abuse of market power distorts the cost distribution that was intended when implementing a particular congestion management method, which may result in perverse incentives being created that were not intended by the scheme. Because the existence of market power yields the risk that the congestion management method will not function as intended, it is highly relevant to evaluate this risk and use the obtained results to build in safeguards or omit a method, that functions properly under ideal conditions, altogether.

Market power can be exerted when one generator or a small group of generators is able to influence the distribution of congestion benefits and costs, which is done by manipulating the market price in case of market-based methods and constrained power bids in case of system redispatch. A generator can alter the market price by withholding capacity, which results in another, more expensive offer to set the market clearing price (MCP), or by offering electricity at a price higher than its marginal cost. Withholding capacity is profitable if the supply curve is steep around the clearing point, because a large generator may slightly decrease its offered volume such that a more expensive offer is accepted. As all generators receive the marginally accepted price, the generator withholding capacity may benefit if the price increase exceeds the losses from selling a smaller volume. An inflated offer will yield additional benefit if the price setting range of the marginal generator is large. The price setting range is large when the height of the next marginal offer is sufficiently high, which allows the marginal generator to artificially increase the MCP without its offer being rejected.

Definition of Residual Supply Index

The extent of market power is quantified by calculating the *Residual Supply Index* (RSI), which was developed by Sheffrin (2002) and argued to be a good indicator of market power in electricity markets by Newbery (2008) and Swinand et al. (2010). The Residual Supply Index indicates the extent to which demand can be met by all generators except for the largest (or any other supply for which one desires to determine the RSI value), and is calculated by the following equation:

$$\text{RSI } [\%] = \frac{C_{total} - C_{largest}}{L_{total}} \quad \text{(Equation 3.2)}$$

If the RSI for the largest generator is larger than 100%, this means that the total load at a given moment can be supplied by the other market players together. A value below 100% indicates that (some of) the capacity of this generator is required to fulfill demand because the other generators have insufficient capacity available to serve the load. A generator in this position is called 'pivotal' under another indicator of market power called the *Pivotal Supplier Index* (PSI). The PSI can be used to calculate the amount of time that a particular generators is indispensable for meeting market demand, when evaluating a market power over a period of time. As is shown by Equation 3.3 below, the PSI results in a binary value of either 0 or 1, indicating that a producer is either 'pivotal' or not. By calculating the PSI for every hour (given hourly market clearance) separately, one can calculate the amount of time that a pivotal producer existed (or will exist, using an appropriate simulation model), thus providing an indication to the existence and severity of market power.

$$\begin{array}{l} \text{PSI} = 1, \text{ for: } C_{generator} > C_{total} - L_{total} \\ \text{PSI} = 0, \text{ for: } C_{generator} \leq C_{total} - L_{total} \end{array} \quad \text{(Equation 3.3)}$$

Because this study will use a model that is not run over time, the PSI can only be used to indicate whether there is a supplier at a particular moment, but without providing any information on the market power of the pivotal supplier, if there is one. Therefore, the RSI will serve as the main indicator for market power in this study. The RSI provides a measure for the extent of market power and indicates the percentage of demand that can be fulfilled without using the capacity of the largest generator at all.

3.3.5 Use of KPIs

The four KPIs discussed above were used to determine the performance of the different congestion management methods that are being evaluated in this study. To this end, all KPIs were incorporated in the simulation model, which is able to calculate their values when different methods are applied under varying scenario conditions. For more information on the implementation of the KPIs in the model, please refer to section 4.4.4. Using the quantitative performance outcomes on these KPIs, a comparative analysis was performed in which the four methods were compared to each other. This analysis and its results are presented in Chapter 8.

The subsequent chapters, which form Part II of this report, discuss the construction and use of the simulation model that was used for the quantitative part of this study (dealing primarily with research sub-question 3). Chapter 4 discusses the conceptualization and model specification processes, Chapter 5 introduces the scenarios to which the congestion management methods are made subject to and the other simulation assumptions, and Chapter 6 presents the results of the simulation runs. The main conclusions with respect to method performance, which follow from the quantitative modeling study, are presented in section 6.4.

PART II:
Quantitative Evaluation of Congestion Management Methods

4 Model specification

In order to gain insight into the effects of the four congestion management methods that were introduced in section 3.2, a simulation model was developed to allows for a quantitative evaluation of their performance when applied in the Netherlands. Using this model, the methods were analyzed for, and compared on the basis of their effects on the key performance indicators that were introduced in section 3.3. The model will be introduced in this chapter, by discussing the conceptual representation of the system, the modeling technique, the verification and validation process, and the most important assumptions for and limitations of the model. An extensive description of the model specification process is provided in Appendix C.

4.1 Modeling objectives

An important element of this study is to provide a quantitative insight in the effects of applying different congestion management methods in the Netherlands (see Chapter 2, research sub-question 3). These effects are to be compared to each other on the basis of the key performance indicators that were introduced in section 3.3. The main objective of this modeling study is thus to obtain quantitative data regarding the performance of the methods, which enables the comparison between different congestion management methods when applied in the Netherlands specifically. The goal of the model specification process is to construct a model that represents the Dutch electricity system at a level of detail that can simulate the application of these methods and is technically able to calculate their effects on the KPIs.

The calculations that need to be performed by the model entail the transformation of model input factors, which consists of the transaction pattern as desired by market players (see section 4.2.3), into output values of the KPIs by means of model calculations that reflect the actual processes that take place in the electricity system in between – or at least to the extent that it results in the same outcomes (i.e. are a representative proxy). Before starting to construct the simulation model, the level and scope of the system that are relevant and must be reflected by the model need to be defined. By means of conceptual modeling the relevant system elements are identified and represented in a manner useful for modeling. The most important consideration during this process is to come up with a conceptual representation of the system that meets the requirements following from the intended application of the model that will be constructed on its basis, i.e. to allow for comparing the effects of applying different congestion management methods. This conceptualization process is discussed in section 4.2.

4.2 Conceptual representation

The first step of constructing a simulation model that must represent some underlying physical system consists of determining which aspects of this system are relevant to model. This delineates the borders of the system that will be modeled and specifies the level of detail in which various elements are included. This section will clarify the perspective on the physical system that was considered relevant for this study, by defining the scope and level of detail in which the Dutch electricity system was modeled. Section 4.2.1 elaborates on the geographic model implementation, section 4.2.2 discusses the modeled stakeholders (i.e. market players), section 4.2.3 deals with the conceptualization of market processes, and section 4.2.4 describes how the transmission infrastructure was conceptualized, i.e. what elements were considered relevant, which were not, and why.

4.2.1 Geographic conceptualization and delineation

Although it is not surprising that the geographic scope of the model includes the Netherlands, it is relevant to elaborate on the manner in which the Dutch electricity system was modeled and how it is assumed to interact with neighboring power systems. Among the main reasons for conducting this study is the (planned) construction of new production units in geographic areas that already have a surplus of production capacity, which is expected to result in increased transmission requirements to transport the excess of electricity to other regions. The model thus needs to be sufficiently detailed to be able to capture flows from one of such locations to another, potentially resulting in congestion. This was achieved by assuming that the Netherlands consists of four congestion regions (defined as nodes), with transmission capacity limits applying for transports among them, but assuming that they have sufficient capacity available internally at all times.

Although a highly detailed model that includes every power line, transformer, and substation would adhere to the modeling objectives, it would take a disproportional amount of time to construct while not adding much value with respect to the research questions at hand, when compared to the nodal approach taken during this study. After all, the main research objective of the modeling study is to compare the outcomes of different congestion management mechanisms when applied in the Netherlands, rather than calculating the exact loads that are placed upon single grid elements.

The Netherlands is considered to consist of four congestion regions: North Netherlands (with production capacity in the Eemshaven industrial area in particular), the Ring (the area covered by the physical 380 kV ring-structure), the Maasvlakte (an industrial area where a significant share of new production capacity is planned), and Zeeland (including the Moerdijk industrial area). This is indicated in Figure 3. Every congestion region is modeled as a node, which includes producers and consumers, and has transfer capacities with other nodes that reflect those of the physical system. Inherent to defining nodes is defining nodal borders, i.e. determining the geographic area that falls under a particular congestion region. The congestion region (nodal) borders were defined such that the modeled interconnections represent bottlenecks that exist within the physical system, i.e. transfer capacities within the nodes exceed capacities between them. This "bottleneck approach" is required if the assumption that no congestion exists *within* a node is to be held true, because otherwise the model would yield outcomes that were completely meaningless. A complete specification of the nodal borders (i.e. the nodal coverage areas) and an explanation for these is provided in Appendix D.3 (Table 25).

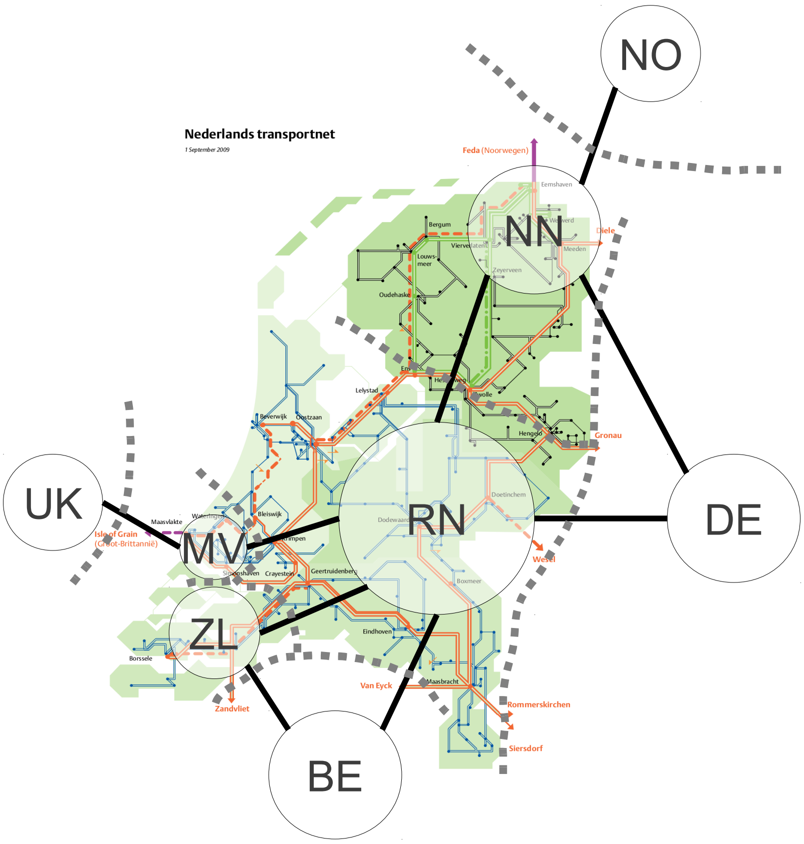


Figure 3: Nodal representation of the Netherlands

Interconnected electricity systems

The interconnections between the Netherlands and Germany, Belgium, Norway, and the United Kingdom are also taken into account, but treated as an external factor that influences the system at its system boundaries (i.e. the boundaries of the Dutch transmission system). The electricity systems do not influence each other, and the neighboring countries are considered as generators (that supply electricity within the Netherlands), or as loads (which consume electricity within the

Netherlands). Electricity trade with these countries is modeled by assuming that each of these countries has a fixed MCP (which depends on their marginal production unit; see Appendix D.1.1), the height of which determines whether electricity is exported to or imported from these countries. For instance, trade with Germany is modeled by including an offer (at the height of MCP in Germany with a volume equal to commercially available transfer capacity) and a bid (of equal height and volume[17]). If Dutch MCP is higher, then the Germany offer will be accepted as if it were a generator (with its demand bid being rejected), and if Dutch MCP is lower than in Germany, this happens the other way round.

4.2.2 Market players: producers, consumers, and the TSO

In reality there is a wide variety of market players active in the electricity sector: consumers, distribution companies, suppliers, retailers, a TSO, producers, hedge funds, regulators, (spot) market facilitators, wholesalers, speculators, metering companies, traders, and integrated combinations of two or more of the former. In spite of this large number of roles and functions, the technical system only consists of consumers that place a load, producers that generate power to serve this load, and network companies that facilitate the transportation of this power from producer to consumer using the transmission and distribution infrastructure. As the Netherlands is divided into four nodes during this study, all of which have infinite transport capacities internally (see section 4.2.1), the distribution companies no longer play a role in the model. From a technical perspective there are thus only three types of actors that are relevant for congestion: producers, consumers, and TenneT.

Under perfect competition these would also be the only actors active in the electricity market. The existence of all other parties incurs a cost to society and no rational actor would spend money on something they do not need (hence, the maximum possible profit margin for these non-technologically relevant market players equals zero). Because of market imperfections, however, there is room for these players to stay in business in reality: they reduce the negative financial consequences of market imperfections, and make a profit by doing so. For instance, retail companies exist because high transaction costs prohibit individual households from negotiating their supply contracts directly with a producer. Similarly, the mere fact that traders have a profit margin greater than zero, is because there are producers that do not know whom to sell their electricity to at a price that is higher than the trader is willing to pay them (or finding out comes at a cost, which outweighs the benefit). If these parties would exist under perfect competition, their maximum profit margin would equal zero – and as a result they would not exist in such a situation.

Because evaluating the consequences of market imperfections itself falls outside the scope of this study, perfect competition is assumed. This enables the assumption that these three technologically relevant players are the only players active in the electricity market.

With respect to the seemingly contradictory elements of analyzing strategic bidding – which, as was discussed in Chapter 2, is one of the objectives of this study – while assuming perfect competition, note that these aspects comprise different parts of this study. First, the application of different congestion management methods is simulated under competitive conditions, in order to create a quantitative insight in the outcomes of their application. The results from this simulation study, which *inter alia* provide detailed knowledge and data about the (optimal) dispatch of generation units, allow for a subsequent analysis of the opportunities for generators in the Netherlands to bid strategically. This was done by constructing a number of "business cases", each of which represents a type of game that is shown by literature to offer a possibility for generators to increase profits. The model enables the simulation of these business cases, while taking into account the real characteristics of the Dutch electricity market, which allows for an assessment of 1) whether generators could apply the (theoretically existing) strategy in reality to increase their profits, and 2) if so, the extent of the consequences thereof in terms of cost and cost allocation.

17 If commercially available import and export capacities are different, the volumes virtually supplied and demanded may also differ.

4.2.3 Conceptual representation of market processes

As was explained in section 4.2.2, this study only considers the existence of three types of market players: producers, consumers, and the TSO. The behavior of all these players, which is separately discussed in the sub-sections below, results in a pattern of electricity transactions that these players desire to have physically implemented. These desired transactions form the input for the model, on the basis of which generation unit dispatch and transmission flows are calculated. This section discusses the behavior that these market players exhibit.

Under perfect competition, supply and demand meet as if an efficient, mandatory spot market with no transaction costs was in place, with producers offering electricity to this market and consumers having a demand for electricity. This section discusses the behavior that producers, consumers, and the TSO would exhibit in a system that has the feature of perfect competition.

Producer behavior

In reality there are many different types of transactions that take place between the different types of market players that are active on the electricity market. Electricity is traded in different products, and these products are bought and sold for a wide variety of reasons. When electricity suppliers (which do not necessarily need to possess their own generation units) offer electricity to the market in the form of spot market trade, over-the-counter or a bilateral contract, they may have a variety of considerations (e.g. power plant start-up costs, fuel contracts, risk assessment strategies) that eventually determine the volume they offer and the price at which they do so. Under the assumption of perfect competition, however, these considerations play no role and the optimal strategy for producers (considering them to be profit-maximizing entities) is to offer all electricity to the market at marginal costs[18].

All producers are assumed to dispatch the units with cheapest variable costs first, whenever this is possible. The offers they submit to the mandatory spot market are in principle assumed to be based upon these actual production cost, as was discussed above. For these reasons, all production units needed to be included in the model separately. The model thus contains an overview of all units currently present in the Netherlands, including data on the generators that own these units. The nature of the indicator *Residual Supply Index* (see section 3.3.4) requires that the units can be assigned to a single producer, in order to calculate the RSI value of a particular producer (most importantly: the largest producer) – which may possess more than one unit – in a node. Also, this information is required in order to assess generators' opportunities for strategic bidding (discussed in section 6.3).

Very small producers (units smaller than 60 MW) were not modeled separately, but included as an aggregated producer which is called the “competitive fringe” and is dealt with as in Lise et al. (2006). They assume small producers to be price takers that are not able to artificially influence the market price by themselves. Their capacities and offers together have a significant influence to the market, but individually this influence is negligible and therefore not required to be modeled separately.

Summarizing the above: producers are all included in the model separately, with each of them initially offering the capacities of all available units at marginal cost.

Consumer behavior

Unlike producers, consumers are not modeled individually as dealing with individual consumers and their potential market power falls outside the scope of this study. Because power flows between different congestion regions are determined by the location of demand, all consumers are aggregated on a per-node basis, which results in separate demand functions for every node. Given the fact that short-term demand is very inelastic (Ackermann, 2007; also see Appendix D.1.2) these 'curves' are assumed to be vertical during this study: price fluctuations thus have no influence on

18 Generators may supply multiple offers if they own multiple units that each produce at different marginal cost.

short-term electricity consumption. The model could also be run using true demand curves, however.

TSO behavior

The first step in the model simulates a power exchange that determines the trade volumes and prices of electricity that market parties desire to exchange. The role of the TSO is to determine the scheduled flows that would result if this transaction pattern were to be implemented. The model assumes that TenneT is provided with all information it requires to determine these flows, given a particular market outcome (i.e. all generators have submitted their T-programs). Using this information the simulated TSO can determine whether congestion arises and, if so, provide the power exchange with the relevant information on ATCs or required redispatch capacities (depending on the congestion management method applied), on the basis of which a new transaction pattern can be determined after taking into account the market effects of the congestion management method.

TenneT must be included as a separate entity because it can be affected by the distributive effects of congestion costs and benefit allocation when applying congestion management. This element also applies to foreign TSOs, which are TenneT's counterpart in cross-border trade.

4.2.4 Relevant transmission elements

Physically, the transmission and distribution systems for electricity consist of an integrated network of power lines at different voltages and with different capacities. Because this study assumes the capacities of the infrastructure *within* congestion regions (represented by the nodes) to exceed those *between* them at all time, the only constraint that is relevant for the simulation study is created by the inter-node available transfer capacities (ATCs). If the transaction pattern as desired by market parties cannot be technically implemented, the application of a congestion management mechanism is meant to result in adjusted unit dispatch and load patterns *(note that the latter is not taken into account in this study)* which can be technically implemented. How these ATCs are determined and how they can be influenced (e.g. by reinforcing the grid or applying dynamic rating) is not relevant for the congestion management mechanism at the time when it is applied. The system behind the mechanism 'gets' the ATC values from the physical system (i.e. the engineers responsible for this system determine these – this is also simulated by the model) and its sole objective is to adjust dispatch and load patterns such that the resulting flows do not exceed this constraint.

The implications of the above are simple: for the purpose of modeling the application of congestion management mechanisms, the transmission system can be conceptually represented as a set of ATCs that determine the maximum flows between nodes. The process of determining the right values to be used by the model was more extensive. Please refer to Appendix D.3 for more information on these calculated aggregate transfer capacities between nodes.

Note that the capacities assumed by the model already incorporate safety and reliability margins that are taken into account by TSOs when scheduling flows. Also, the capacities assumed in the model are based on an n-1 safe configuration. This means that if any one circuit were to fail anywhere in the grid, power supply would remain uninterrupted as long as the flows imposed are smaller than the ATC value (note that if a circuit malfunction would occur in reality, the grid may no longer be operating n-1 safe. Measures would then need to be taken in order to return to this state. This falls outside the scope of this study, however.)

Cross-border trade and electricity flows

Because power flows are not solely determined by differences in net demand among congestion regions, but also depend on the physical characteristics of the grid, congestion may arise when power from an adjoining region ("power source") flows through another before it reaches its destination ("power sink"). To illustrate this, consider the simple three-node network depicted in Figure 4. Every grid segment has an equal reactance (X=1).

Given the differences in net consumption, 300 MW needs to flow from A to C for the system to be balanced. Although line A-C has sufficient capacity to accommodate all 300 MW, one-third (100 MW) will use the route A-B-C because this allocation results in the least-resistance transfer. Because the line between B and C has a capacity of only 50 MW, congestion arises as 100 MW would flow through this line segment if the production/consumption-pattern were to be physically implemented. The power flow from A to C therefore creates congestion, even though the infrastructure between A and C itself would appear to have sufficient capacity to accommodate the flow.

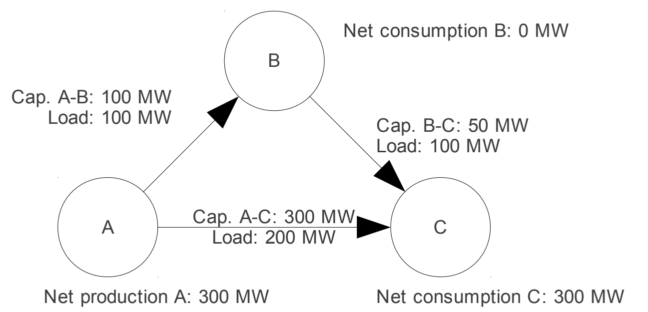


Figure 4: Example of discrepancy between congested lines and regions

In this example congestion must be mitigated by decreasing the flow required over B-C, while not increasing the flow over A-B (as this segment is already operated at its thermal limits). There is no solution but to increase generation in C, because a shift in generation from A to B would only increase the load on line B-C – which is already congested – in this example, so the “amount” of congestion should, using the definition introduced in section 3.3.1, be calculated by the amount of constrained on power that is required in node C as a share of its (initial) net consumption.

Directive 2009/72/EC lays down that TSOs should ensure “the secure and efficient operation” (Article 12(e)) of interconnected transmission systems. However, operating interconnections as an individual TSO in a large integrated network without centralized system responsibility, as is the case in Europe, requires a trade-off between the requirements “secure” and “efficient”. Because electricity flows in a distinct part of the interconnected network, which is not under the authority of the TSOs involved in the interconnection, may lead to additional loads that cannot be known well ahead in time, TSOs need to be conservative when determining the commercially available capacity (Brunekreeft et al., 2005). They need to “anticipate the largest possible impact the unknown flows (…) could have on the network” (Brunekreeft et al., 2005, p. 83) which as a result leads to underutilization of the network.

Note that although the capacity nominations applicable to the Dutch-German and Dutch-Belgian interconnections may fluctuate over time, this study considers the values provided by Hers et al. (2009a) to apply generally and will not take into account the considerations of TSOs with respect to this issue any further, because it falls outside its scope. For the interconnection data used by the model, please refer to Appendix D.3.

Determining the commercially available capacity could also be used by TSOs to solve internal congestion. If node A in the example shown in Figure 4 were located in a foreign country, and power lines A-B and A-C would be interconnections between these countries, the TSO could influence the amount of power that the market desires to transport from A to C (and thereby also the power flow) by altering the nominated capacities of these power lines. By nominating the capacities of the interconnections A-B and A-C sufficiently low, the market transaction pattern may be changed such that the physical load on B-C is decreased, thereby solving the TSOs own, internal congestion. It is relevant to point out that such behavior decreases total system efficiency, and is contrary to Article 12(e) of Directive 2009/72/EC. Nevertheless, Glachant & Pignon (2005) argue that slight manipulations of ATC nominations do occur in reality, for instance in the interconnected Scandinavian electricity systems where TSOs apply the measure “to relieve a real and costly internal congestion” (Glachant & Pignon, 2005, p. 161).

4.3 Modeling technique

The modeling objective of this study is to provide a quantitative insight in congestion and the application of congestion management methods in the Netherlands, using the KPIs that were introduced in section 3.3. A major contribution of this study is that it allows for a detailed determination of dispatch and redispatch costs, which is what many economists focus on according to Lesieutre & Eto (2004). Rather than incorporating production units as generic categories, for instance as a small number of aggregate unit types that represent e.g. the different fuel types available, this requires a model that is able to provide a detailed insight in the underlying causes of congestion on the level of individual production units, all of which are owned by an electricity producer that is active in the electricity market. The model that was constructed takes all these individual units and their characteristics as the starting point for dealing with congestion: every producer has a specific cost structure, which depends on the production units they have in place. Each of these units can generate electricity at a specific cost, which depends on factors such as fuel type, age, and technology. Together, these determine the overall dispatch pattern for the Netherlands, which results in a scheduled flow pattern for the transmission system.

When all (relevant[19]) production units are considered individually, one can gain insight in which specific units are dispatched under particular circumstances. Also, and perhaps even more importantly, one can simulate which units will still be available in this situation. This provides important information in case congestion occurs. When the scheduled flows result in congestion and a congestion management method is applied, this must result in a change of the dispatch pattern. Data on which units are already dispatched and which are still available provides useful information on the underlying cause of congestion costs and supports the identification of possibilities for producers to bid strategically.

4.3.1 Contribution to existing literature

Lise et al. (2008), Leuthold et al. (2008), Veit et al. (2009), and Weigt et al. (2010) have also performed simulation studies in which models were constructed to simulate the application of congestion management in an existing situation (more specifically, Europe and Germany). These models do not take a purely theoretical approach to evaluate congestion management mechanisms, but aim to gain a practical insight into real problems. Their approaches have in common, however, that the generation side is not incorporated in the model in full detail, but treated as generic categories of generation units. According to Lesieutre & Eto (2004) the lack of readily available data that is required to measure congestion costs on an accurate level is a common problem for many studies. Because the current study is performed in close cooperation with TenneT, data that is not normally publicly accessible was made available and provided a valuable source of information that greatly added to the significance of this study.

Furthermore, market power issues were ignored by the aforementioned authors (with the exception of Lise et al. (2008), who have done research on the impact of dry weather and the possibilities of 22 large companies to exert market power on a European level). The model constructed during the current study therefore contributes to existing literature by simulating the Netherlands distinguishing four internal nodes, rather than considering the country as a single price area, as was the case with the European models of these authors, and also by allowing for all generators (and their opportunities to exert market power) to be analyzed separately on the Dutch market.

The succeeding sections introduce the model and discuss its characteristics. Its performance will be evaluated in section 4.7, which will include a reflection on the technique presented in the current section.

4.3.2 Modeling tool

The implementation of the conceptual representation of the system described in section 4.2 requires a tool that is able to perform the following calculations:

19 Whether a unit is relevant depends on its capacity. Small units (< 60 MW_e) are not modeled separately, for this would not contribute to the study objectives. This is explained in Appendix D.2.

- distinguish between separate production units,
- include for these units information on:
  - (fuel) type
  - capacity (in MW_e)
  - efficiency
  - location (congestion region)
  - owner
- marginal supply costs differentiated to separate units,
- traded volume and market price, on the basis of demand and supply curves,
- optimize dispatch of units (per producer), given supply obligations and units information,
- transmission flows, given net demand or supply per node,

Most of these functions can be performed by means of static calculations, because the system is not simulated over time. The model performs calculations to calculate values for the KPI variables x, y, and z, on the basis of input conditions a, b, and c. The model contains one optimization element, however, which is used to determine the optimal unit dispatch for every producer, considering that it aims to keep dispatch costs as low as possible, under the constraint that they must adhere to their supply obligations.

Given the large amount of data that the model must contain on every individual production facility and with the above requirements in mind, the model was implemented using the spreadsheet application of the office suite OpenOffice.org 3.2[20]. This application includes an optimization tool and, as a spreadsheet application, it can perform the other calculations (which are mathematically basic, but extensive in number) and, whenever required, look up data that is contained by other parts of the document. Section 4.4 will discuss how the model was constructed on the basis of the modeling objectives and the conceptual representation of the system that have so far been discussed.

4.4 Model construction

On the basis of the modeling objectives (discussed in section 4.1), the conceptual representation of the system (section 4.2), and the functional model requirements (section 4.3), a simulation model was constructed that allows for a quantitative evaluation of congestion management methods in order to answer research sub-question 3. The most important aspects of (the construction of) this simulation model are discussed in the current section, whereas a more detailed elaboration is provided in Appendix C.2. Please refer to Appendix C.3 for a description of how the model is actually used, i.e. which manual steps need to be performed during a simulation run.

4.4.1 Model structure

As has been discussed before, congestion is defined by a situation where transactions as desired by market parties cannot be implemented physically due to transmission constraints. In other words, congestion arises after some kind of market process has resulted in a set of contracts for power deliveries, which turns out to be unfeasible when the effects for the physical system are calculated. Modeling the electricity system for the purpose of evaluating congestion management thus needs to include two elements: 1) the market processes that take place among all market players which determines who generates electricity and who consumes electricity (and where), and 2) the system used to determine the impact on the transmission system, on the basis of these transactions.

Because, in reality, producers may own generating units in different regions, it is not sufficient for the model to merely determine the volume of electricity that is fed into the grid by a generator in total, as units may be dispatched in different congestion regions according to whatever

20 It is also fully compatible with Microsoft's Excel.

considerations the generator may have. The model should therefore also simulate the dispatch decisions that are taken by generators, as these eventually determine the T-programs that are submitted to the TSO. Note that this is actually also the case for large consumers, if they own multiple facilities across the country. Because the inclusion of individual consumers falls outside the scope of this study (see section 4.2.3), this was assumed not to have an influence.

A schematic overview of the model structure as described above is shown in Figure 5. This overview schematically presents the three distinguished model elements, from market interaction to either or not detecting congestion, with a different sub-model simulating the optimization of unit dispatch decisions by individual producers. All three sub-models are separately discussed in brief below. For a more elaborate discussion on their incorporation in the simulation model, please refer to Appendix C.2.

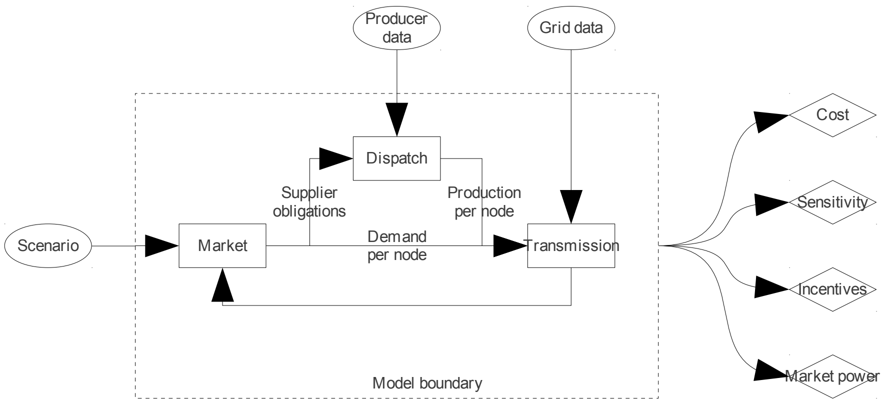


Figure 5: Conceptual electricity system representation

Market

In the current, liberalized, Dutch electricity market, transactions between market players and the physical transport of electricity take place as completely separate processes, which are the responsibility of different stakeholders (market players and the network companies, respectively). In principle, physical electricity flows are simply determined by the outcome of a series of market processes, during which market players trade electricity for a variety of reasons. Despite the potentially complex structure of transactions that takes place in reality, section 4.2.2 explained how the market would, under the assumption of perfect competition, eventually function (and yield the same outcomes) as if all producers and consumers participated in a single, mandatory spot market. The first element of the model thus needs to simulate this process.

Dispatch

The physical characteristics of electricity require production and consumption to be equal at any time in order for the electricity system to function properly. The responsibility of maintaining this balance resides with the TSO and the *program responsible* parties. In reality, program responsible parties may act on behalf of other (usually small) players for whom it is more efficient to transfer this responsibility rather than deal with it themselves (e.g. households or small producers). The model assumes that all individual producers are separate program responsible parties, which means that they must make sure to actually feed exactly the amount of power they have sold on the market into the grid (i.e. their supply obligations in MW). Producers are free to dispatch any unit(s) they have available to fulfill these obligations, as long as the total volume sold equals the total volume produced. As a result of this, the market outcome itself does not directly determine the dispatch in every node if a producer possesses multiple generation facilities across multiple nodes. The actions that eventually determine how much electricity is produced in each node (which is required to calculate the resulting transmission flows) must therefore be modeled separately. This is done by the *Dispatch* sub-model, the functioning of which is as follows.

Because producers are assumed to exhibit profit-maximizing behavior under the assumption of perfect competition, their strategy consists of finding the least-cost dispatch, under which the cheapest units are dispatched first. A producer will thus only dispatch an expensive unit if all cheaper units are already dispatched (or unavailable) while its supply obligations are not yet all covered by actual production. This constitutes an optimization problem, in which each producer seeks to minimize costs (arising from the dispatch of units), under the constraint of dispatching sufficient capacity to fulfill their supply obligations.

Note that when perfect competition is assumed when running the model, there will be no discrepancy between supply offers and the corresponding units that will actually produce the power offered. Both the offers accepted in the *Market* sub-model, as well as the units dispatched in the *Dispatch* sub-model, will be based on a 'lowest cost-first' basis. The model nevertheless distinguishes both sub-systems, because this allows for it to be used to simulate a situation where producers do *not* offer capacity at marginal cost (e.g. when bidding strategically), but still dispatch their cheapest units first to maximize profits.

Transmission

In order to determine whether the market transaction pattern and, consequently, the dispatch of units is technically feasible, the *Transmission* sub-model calculates the resulting flows between the nodes. Differences in net consumption (consumption minus production; negative consumption is net production) determine whether electricity flows towards a node or away from it (explained in Appendix C.2.3), while the distribution of the power flow over the different paths available is incorporated in the model as a set of power transfer distribution factors (PTDFs) (see Appendix D.3).

When calculating the flows that are being imposed on the nodal network (depicted in Figure 3) one seeks to find a flow pattern[21] that results in the supply of electricity (production or imports) and load (consumption or exports) to be balanced within every node, while the power flows between these nodes adhere to the PTDFs that are determined by the physical elements of the system (which serves as an external constraint, that cannot be influenced). Although electricity will flow from regions with excess production to regions with a shortage (this is discussed in Appendix C.2.3), power may not always flow directly from excess to shortage regions because these physical grid characteristics make it flow differently. By formulating the flow pattern calculations as an (minimum flow) optimization problem[22], under which electricity flows must be minimized while adhering to the constraints that 1) all nodes are in electrical balance and 2) those implied by the PTDFs, one can apply a linear programming algorithm to find the flow pattern that results from a given pattern of unit dispatch and load.

This simulation sub-model results in an overview that shows how much power would be transported over the different grid elements under this scheduled dispatch and load pattern. If thermal capacities would be exceeded if these scheduled flows were physically implemented, the model will indicate the congestion regions for which the required imports or exports are technically unfeasible.

Congestion: an iteration

If the *Transmission* sub-model indicates congestion, the four methods discussed in section 3.2 are applied (one-by-one) to alleviate congestion. A variant of the *Market* sub-model will be used, which is constructed as to simulate the market process that is used by the congestion management method under consideration. The outcome of this market process will subsequently be used to simulate the new unit dispatch optimization decisions, and the new resulting flows are calculated to determine whether the new transaction pattern can be implemented. If this is not the case, the market process of the method is repeated iteratively until congestion is alleviated. Please refer to Appendix C.3 for more information on how this was technically implemented in the model.

21 The 'flow pattern' is basically an overview that indicates how much power is transported over every separate connection between nodes that are connected to each other.

22 Appendix C.2.3 elaborates on the reasoning behind formulating this calculation as a minimum flow problem.

4.4.2 Model data

The data requirements that were identified on the basis of the modeling objectives and model functions, described in the preceding sections, are listed in Table 5 below. This table also indicates the sources from where these data were retrieved.

Data	**Sources**
Production units - Capacity - Owner - Fuel type - Efficiency - Location - Merit order rating	- Data sheet including all production facilities larger than 10 MW, provided by TenneT (confidential) - Quality and Capacity Document (TenneT, 2009a) - Data on future wind farms, see Appendix G.3
Load development (per congestion region)	- Data sheet including loads differentiated to sub-station level, provided by TenneT (confidential)
Transmission infrastructure - Capacities - Reactances - Planned development (e.g. creation of load pockets)	(Hers et al., 2009a)
Expected electricity prices in DE, BE, NO, UK - On the basis of expected marginal unit	(TenneT, 2009a)

Table 5: Identified model data requirements

4.4.3 Congestion management methods

This section discusses the model-technical implementation of the congestion management methods that are evaluated during this study. These methods, which were introduced in section 3.2, all require to be implemented in the model differently, because they differently interact with the generic model components (see section 4.4.1) and use the data it contains in a different manner. For instance, market splitting initially requires the model to calculate a system outcome as if all producers and consumers were part of the same region, whereas market coupling requires that all regions are viewed separately at first and couples these in second instance. The following subsections discuss the implementation characteristics of the congestion management methods individually. For more information on the methods themselves, please refer to Appendix B.

Furthermore, it is relevant to note that the model deals with congestion as a national affair, as is laid down by European legislation (Directive 2009/72/EC). This means that cross-border transactions are determined on the basis of regarding the Netherlands as a single congestion zone. Internal congestion is dealt with *after* applying this European market coupling mechanism. If internal congestion indeed arises, the cross-border transactions are considered to be fixed and will no longer vary when a mechanism is applied to deal with this congestion. Differences in congestion rents that may arise after a congestion management method is applied to solve internal congestion will not be transferred to the foreign TSO, but borne nationally by TenneT, i.e., foreign TSOs should not “notice” that congestion management is applied by a change of their financial benefits.

Basic system redispatch

The basic system redispatch method is simulated not only to gain a quantitative insight in the effects of it application, but also because it serves as a reference to the outcomes of other methods. All generators place separate bids and offers in *constrained off* and *constrained on* markets, which are facilitated by TenneT. The mechanism makes use of the notion that producers are willing to pay an amount up to their variable cost of production for not having to produce.

The model simulates basic system redispatch by clearing the market as a whole in first instance, and subsequently determines the unit dispatch pattern and the resulting transmission flows. If congestion is observed, the model will calculate the change in production levels in the different congestion zones, that is required to solve congestion. This volume is determined using an optimization algorithm: because any dispatch pattern that deviates from the original market outcome will be economically sub-optimal, the optimization algorithm that is used seeks to minimize the volume that needs to be redispatched, under the constraint transmission flows are brought back within the existing limits. This step results in a figure of the amount of power [MW] that needs to be redispatched from the upstream area to the downstream area, which is used as input by the simulated *constrained off* and *constrained on* markets.

On the basis of *constrained off* market bids, some producers whose offers were accepted initially now also must "dispatch" *constrained off* capacity (i.e. regulate down). Their supply obligations are thus such as shown in Equation 4.1.

$$P_{dispatch} = P_{market} - P_{Coff} \qquad \text{(Equation 4.1)}$$

In the downstream congestion zone, the supply obligations of some producers – whose *constrained on* offers were accepted – will be increased. This volume will in total also be equal to the minimum redispatch volume that was determined as discussed above.

Market splitting

Similar to the "basic" model elements as discussed in section 4.4.1 the simulation of market splitting is done by clearing the market as a whole, determining unit dispatch, and calculating the resulting transmission flows. If these flows turn out to be unfeasible, the nodes are grouped in two (or more) zones which are not congested internally under this dispatch scheme, but where congestion does occur in between. The markets are cleared in a two-step process: first, the maximum flow from one zone to the other is determined. If the network is not meshed, the maximum flow can be easily obtained as it is equal to the ATC of the power line that connects these zones. In case of a meshed network, the calculation also needs to take into account the PTDFs and ensure that the determined maximum flow between the zones does not result in the capacity of any single grid segment to be exceeded.

The second step makes use of so-called *price-independent* bids and offers, also known as *virtual* bids/offers. Under the market splitting mechanism, the electricity system is split into two (or more) zones that are cleared separately. To use the available transmission capacity to its fullest extent, the TSO and/or power exchange adds a supply offer equal to ATC to the supply curve of the high price area (to be supplied by the low price area) and adds a demand bid (of equal volume) to the demand curve in the low price area. This virtual offer and virtual bid is by definition accepted by the market and is therefore called *price-independent*. This process is schematically shown in Figure 6. The top figure shows two areas, in which Area 1 produces a quantity Q that is exported to area 2, which places a load and consumes this electricity. If congestion would arise, because transmission capacity (Q_{limit}) is exceeded, the bottom figure shows how a virtual bid and virtual offer are added to the markets in areas 1 and 2 respectively when market splitting is applied. Because these virtual bids are equal to Q_{limit}, transmission capacity will not be exceeded, but used to its maximum extent.

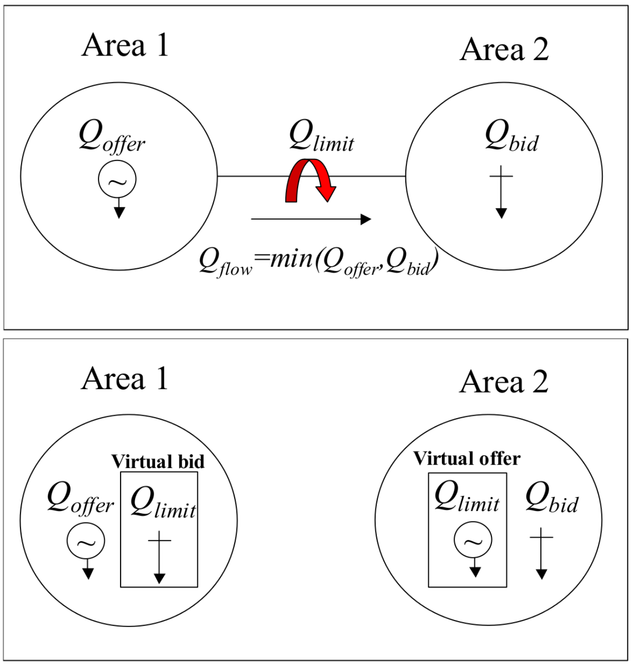


Figure 6: Concept of price-independent bids and offers (source: Marmiroli, 2008)

On the basis of these price-independent bids and offers, a new market outcome (price/volume-pair) is calculated for the separate (now split) markets. Subsequently, the *Dispatch* sub-model is run again to determine the units that will be dispatched. Because producers must now fulfill their accepted supply offers by dispatching capacity within the respective congestion zones, the unit dispatch pattern will by definition not result in congestion to arise. (Note that this sub-model must be run nonetheless, in order to adequately calculate the new welfare distribution which depends on generator dispatch costs. These are different from the not-congested situation, unless the variable costs of the redispatched units are exactly equal.)

Market coupling

Under the market coupling method, the markets are initially cleared separately in each node, and subsequently coupled in order to make efficient use of the available transmission capacity. The individual market clearing mechanisms calculate four different prices, i.e. one for each of the four different nodes (note that foreign prices are assumed fixed by this study; see Appendix D.1.1). This determines the direction in which electricity should be traded when the markets are coupled: consumers in high price areas are willing to pay up to their market price for electricity imports from low price areas, so as long as the price in an adjoining region is lower, electric power would be imported.

The model assumes that the market coupling process that takes place is similar to the mechanism that is currently applied in the CWE and Nordic region by the EMCC[23]. This mechanism is called *tight volume coupling*. Under this mechanism a central authority calculates the optimal market coupling flows (MCFs) between the coupled regions on the basis of their individual power exchange (PX) outcomes, given physical transmission constraints (called market coupling capacities, abbreviated MCCs). The 'optimal' flows are determined on an economic welfare criterion (EMCC, 2011). This study makes use of a similar, albeit simplified welfare criterion, which is defined as the market price difference of two adjoining regions multiplied by the traded volume. The optimal MCFs under this definition are then calculated by an optimization algorithm, which seeks to maximize economic welfare while keeping physical power flows within transmission constraints (i.e. the MCCs). Once the optimal MCFs are determined, additional bids/offers are added to the separate PXs in the same fashion as the price-independent bids and offers under market splitting (see Figure 6), and final prices and volumes are determined for every node.

Note that this method mitigates congestion ex ante, because transmission constraints are already taken into account when calculating optimal MCFs. The KPI dealing with congestion costs is therefore calculated by comparing the welfare under market coupling to welfare under optimal dispatch, which is calculated by all other methods initially.

Furthermore, it is assumed that the market coupling method is applied in the light of the North-West European market coupling mechanism. The four nodes that are distinguished in the Netherlands are considered to be cleared within the European market coupling mechanism at its highest level, i.e. the Netherlands is not cleared as a whole in first instance, but the four nodes are included separately in the EMCC mechanism that is applied for the whole region. Because an MCP for the Netherlands as a uniform market would no longer be determined in the process, TenneT will no longer need to compensate the interconnected TSOs for deviations from this uniform MCP that would alter the congestion rents from interconnector usage.

APX-based method

Under the APX-based method the production level in areas upstream of a congested line are regulated down and production in the congested downstream area is regulated up. If congestion occurs, the capacity required to be redispatched from one congestion zone to another is determined in a manner similar to the basic system redispatch method described above. The upstream producers that must reduce their output are determined on the basis of bids from offers that were

23 European Market Coupling Company.

initially accepted (not-accepted offers cannot be *constrained off*) and downstream constrained on power is acquired from offers that were not accepted (and are thus still available to supply *constrained on* power). This is done by rejecting the most expensive (initially accepted) offers in the upstream area, up to a volume necessary to solve congestion. These *constrained off* producers are not compensated. An equal volume of power is acquired by TenneT in the downstream area, by accepting some of the offers that were initially rejected (i.e. this is the *constrained on* power). These producers are paid their marginal cost of production by the TSO, which incurs a cost equal to the cost of constrained on power minus the benefits from constrained off payments. Note that the MCP paid by consumers does not change in any of the areas.

Because the compensatory *constrained on* power that needs to be acquired in the downstream area is, by definition, more expensive than the power that was *constrained off*[24], a cost is incurred for TenneT. This cost is transferred to generators in the upstream area (that are not *constrained off*), by decreasing the price they receive to a level that is sufficient for the TSO to recover its redispatch costs. However, the price they receive will never become lower than the height of the most expensive marginal offer that is still accepted after *constraining off* some capacity.

Although the APX-based method seems similar to basic system redispatch (see below), it is important to point out that *constrained off* and *constrained on* capacities are auctioned implicitly and without the need for separate redispatch bids/offers to be submitted by generators. Only the initial, "regular", offers are used to determine which producers must be *constrained off*, and which (initially rejected) capacity is accepted in second instance as compensatory power. Basic system redispatch, on the other hand, requires additional markets to be organized, to which producers submit (possibly different) *constrained off* bids and *constrained on* offers.

Note that renewable energy sources can also be exempted from taking part in the *constrained off* scheme under the APX-based method. These offers will thus always be accepted insofar as their height is below MCP. A similar approach is taken with respect to foreign supply and demand, because under current European regulation congestion should be regarded as a national problem. The exception here is that foreign supply that was not accepted initially will not take part in the *constrained on* market, whereas initially rejected expensive renewable offers can be accepted as *constrained on* capacity.

4.4.4 KPI calculation functions

Section 3.3 introduced the KPIs that are used to evaluate the outcomes of the congestion management methods. This section discusses how each of these KPIs was incorporated in the model by discussing the calculations the model must perform and which data it requires for this.

Region congestion sensitivity (see 3.3.1)

Region congestion sensitivity is quantified by the occurrence of congestion and its extent, when the model is made subject to different scenario-conditions. As was discussed in section 3.3.1, the extent of congestion is defined by the Extent of Congestion Index (ECI) which provides a measure of congestion as a proportion of the availability of generation capacity to serve the load in a particular region. This was shown in Equation 3.1, which is reproduced below for the sake of clarity:

$$ECI = \frac{P_{constrained\ on}}{P_{not\ dispatched}} \qquad \text{(Equation 4.2, reprint of Equation 3.1)}$$

If a region can serve its load when congestion arises, this index will return a value smaller than 100%, indicating that even after redispatching there will be non-dispatched generation capacity available. A value above 100% means that more than the available non-dispatched capacity would be required to solve congestion, and a region thus has insufficient capacity available to provide compensatory power if the scheduled flow pattern cannot be implemented physically.

24 If the height of these offers would be lower than the constrained off offers, these would have been accepted in the first place.

The ECI-index provides a measure to assess how well a region can deal with congestion. The extent to which regions are prone to congestion, i.e. how this value fluctuates over time and/or under different conditions, cannot be determined by the model directly, as this would require a simulation over an extended period of time which allows one to determine how often, and to which extent, regions become congested. During this study the sensitivity of regions to become congested is assessed afterwards, on the basis of the (documented) outcomes of the scenario runs. The static nature of the model only enables the calculation of outcomes for this KPI under a few scenarios. The value of these outcomes may not be generally applicable and therefore should the outcomes only be used for comparison purposes (under the scenario conditions that were used) and not assumed to be generally true.

Congestion cost and social surplus (see 3.3.2)

An important comment must be made before discussing the aspect of social surplus. The real value of electricity differs for different types of consumers and is therefore very difficult to quantitatively determine precisely (van Damme et al., 2003). According to Van Damme et al. (2003) the Foundation for Economic Research (Dutch: Stichting voor Economisch Onderzoek; SEO) estimates the value of one kilowatt-hour to be € 4.27 or € 8.00 in the Netherlands, depending on how it is measured. Despite the difficulties in quantifying the value of electricity in a clear-cut manner that results in a single value, it is clear that it lies one or two orders of a magnitude above its cost.

Because of this, no demand curve was specified, as a result of which it is technically not possible to determine the nominal values for consumer surplus. For calculation purposes, however, the model assumes all (domestic) consumers to bid in the electricity market at a price of € 200 / MWh. Although one must be aware of the fact that the decision to use this value is completely arbitrary, its height was based upon two assumptions:

1. Short-term demand is assumed to be completely inelastic, so bids must be at least above the most expensive generator offer (Ackermann, 2007; discussed in section 4.2.3)
2. The value of electricity is generally much larger to consumers than its cost, which also partly explains the short-term inelastic demand (Ten Donkelaar & Scheepers, 2003; discussed in Appendix D.1.2), so the bid must be well-above regular market price levels.

Equation 4.3 shows how consumer surplus is calculated:

$$S_C = \sum_{Q_{bid}=highest}^{Q_{bid}=marginal} (p_{bid} - p_{market}) \cdot Q_{bid} \qquad \text{(Equation 4.3)}$$

, where p_{market} may differ for consumers in different congestion regions, depending on the congestion management mechanism applied.

Within the scope of this study it is not necessary to calculate the actual consumer surplus, which would be the difference between the value of lost load and the price paid for the same unit of electricity (MCP). The surplus for consumers is thus the difference between the price they would be willing to pay at maximum, and the price at which the electricity is eventually sold. For this study, it suffices to calculate the *difference* in surplus before and after the application of a congestion management mechanism. Assuming that the value of electricity remains equal, this is the difference between the "initial" and the "congested" price paid (multiplied by the traded volume). Given that demand is assumed to be completely (short-term) inelastic, consumer surplus will only be altered by a change in the electricity price. As the purchased volume remains the same with an elasticity of zero, the difference in surplus is easily calculated by:

$$\Delta S_C = (p_{nocongestion} - p_{congestion}) * Q_a \qquad \text{(Equation 4.4)}$$

With respect to generators, surplus is calculated as the difference between the (market) price received and the height of the offer (i.e. the price which should be received by the producer at minimum in order for it to be willing to sell electricity at all), multiplied by the volume sold:

$$S_P = \sum_{Q_{offer}=lowest}^{Q_{offer}=marginal} (p_{received} - p_{offer}) \cdot Q_{offer} \qquad \text{(Equation 4.5)}$$

Note that although the price received ($p_{received}$) is generally the market price, it may also deviate from p_{market} for some producers in some cases, depending on the congestion management mechanism applied. This was discussed in section 4.4.3.

Furthermore, during the simulations the model assumes that electricity trade with Germany, Belgium, Norway, and the United Kingdom does not affect the electricity price in those countries. Consumers and producers in those countries do, thus, not experience any difference in surplus, as they pay and receive, respectively, the same price for their power regardless of whether electricity is traded with the Netherlands. This is illustrated by Figure 7, which shows a 1000 MW price-independent import offer in green. Without this imported volume the supply curve would be shifted to the left by 1000 MW, but this would not result in a different marginal accepted offer and (as a result) electricity price. Also note that the marginal producer which sells less power as a result of foreign trade does not experience a loss of surplus either, because if it were to sell the 1000 MW itself, its marginal cost would equal its revenues, thus resulting in a profit of exactly 0 (given that marginal costs equal the height of the offer). It therefore does not matter financially whether its offer would have been accepted or not. This situation is assumed to apply to all foreign trade, because it greatly simplifies the required data and calculations (it is no longer required to have an insight in the market situations of neighboring countries) while not affecting the validity of the model. This type of market situation could realistically occur.

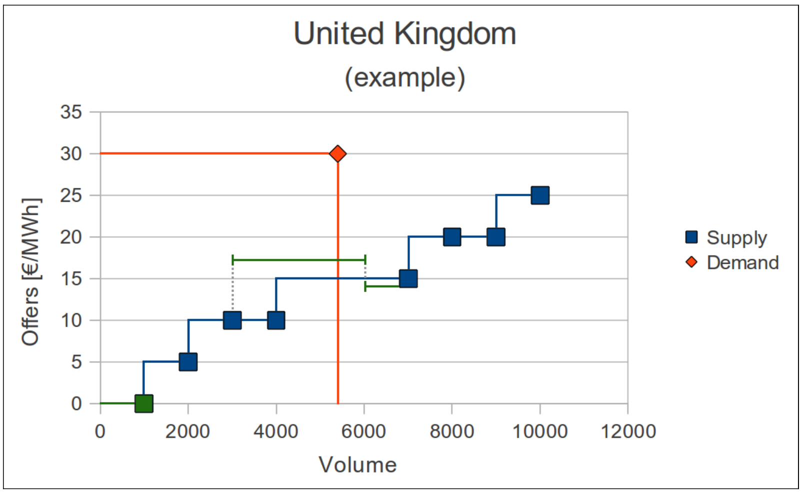


Figure 7: Illustration of fixed foreign MCP assumption

Incentives (see 3.3.3)

The incentives that are created by a particular simulation outcome are assessed manually, by comparing the relative profitability of (new) generation capacity and the relative cost of electricity consumption in a congested area, compared to the non-congested area. If the market outcome (i.e. (locational) market prices) is such, that actions that contribute to solving congestion (both in the short and the long term) become more attractive compared to the hypothetical infinite transport capacity situation, the incentives are considered to be appropriate and desired.

Residual Supply Index (see 3.3.4)

Because an important goal of this study is to identify whether opportunities exist for producers to abuse market power, all producers were modeled as separate entities[25]. This was not done with respect to consumers, for two reasons: 1) according to Lise et al. (2006) the risk of market power being abused by consumers is very small, and 2) insufficient data was available to model all consumers separately.

The presence of market power for producers is measured by means of the Residual Supply Index, which is calculated as follows:

25 Except for producers with a production capacity smaller than 60 MW; see Appendix D.2.

$$\text{RSI [\%]} = \frac{C_{total} - C_{largest}}{L_{total}} \qquad \text{(Equation 4.6)}$$

Note that $C_{largest}$ refers to the total production capacity of the largest producer, not only to its largest production *unit*.

This indicator is calculated for both the Netherlands as a whole, as well as the different congestion zones (e.g. under market splitting) and/or individual nodal regions (e.g. under market coupling).

4.5 Verification and validation

Before drawing any conclusions from simulation outcomes one needs to verify that the model produces reliable outcomes that reflect reality (at least to the extent required). This is done during the verification and validation stage, when the model is tested in various ways in order to determine the validity of the results it produces. The verification process is meant to verify that the model has been coded correctly and is conceptually consistent with reality. Model validation aims to determine whether the outcomes that are produced by the model are valid, and under which circumstances this is either or not the case. The following sections briefly discuss the tests that were performed during the verification (4.5.1) and validation (4.5.2) process, and the outcomes of these tests. For a complete overview and discussion of the performed tests and the results thereof, please see Appendix E.

4.5.1 Verification

The following verification tests were performed to check whether the model was coded correctly:

- Coding of simulation model on the basis of conceptual model
- Spreadsheet formula consistency check

Verification results

After performing the above-mentioned verification tests the coding of the model was found to be specified accurately and consistent with its conceptualization, and found to contain no errors.

4.5.2 Validation

The validity of the model outcomes was tested by means of the following validation tests:

- Extreme conditions
- Sensitivity analysis
- Qualitative characteristics
- Historic data comparison

Validation results

The extreme conditions test revealed an important usage boundary of the model. When multiple bids or offers are at the same price level, but only a part of the volume demanded/supplied is cleared in the *Market* sub-model, the model accepts the bids and offers that it encounters first, i.e. the order in which information is entered determines whether a bid/offer is accepted. On the supply-side this does not have much of an influence, as the supply curve consists of a large number of incremental price steps and as a result the number of occasions that the model must make such an arbitrary “choice” is limited. The demand-side, however, is based upon the assumption that the internal load is fixed and equals a fully inelastic demand curve. This results in invalid model outcomes whenever the total available supply is insufficient to meet demand, as the model will allocate supply capacity based on the wrong criterion that assumes a priority list, while it should not be interpreted as such.

4.6 Modeling assumptions and limitations

As discussed before, a model is always an abstraction of reality. In order to understand under which conditions the model is valid and what its limitations are, it is important to know the assumptions that were made during its construction. The assumptions discussed below partly follow from the simplification of the system during its conceptual representation. This was extensively discussed in section 4.2. Further note that the specific simulation assumptions, i.e. the assumptions that are not an inherent part of the model, but which are related to applying the model for a specific purpose, are discussed in section 5.3.

Assumptions

Four-node network	The electricity system is considered as a four-plus-four node network, which are all assumed to have infinite transfer capacities available internally. All generation and load within a particular node is assumed to take place at the exact same location.
PTDFs	Power transfers among nodes are assumed to be based upon fixed power transfer distribution factors (PTDFs). In reality these PTDFs are not fixed, but influenced by the current pattern of generation and load.
ATCs	All capacities between nodes are considered fixed. Because electricity may follow multiple paths that connect two areas that are distinguished as separate nodes, the real available capacity is influenced by the locations of generation and load within the nodes in reality.
Generation	Generators are assumed to offer all available capacity to the market at variable cost. Unless prohibited by the application of location-specific congestion management constraints, they dispatch their cheapest units first.
Load	All electricity demand is considered fixed, i.e. it is fully inelastic. As a result, (fixed) demand equals (fixed) load. Germany, Belgium, United Kingdom, and Norway are assumed to place a load on the Dutch system if their respective MCP lies below MCP in the Netherlands, and vice versa.
Transaction costs	Transaction costs are assumed to be zero by the model. All market bids and offers, as well as the congestion management payments, are assumed to be transferred without creating a cost itself.
Supply offers	Offers that are supplied at an equal price are accepted on the basis of volume. The largest offers are accepted first, to the extent that the required volume is accepted.
Power transports (“MW=MVA”)	Only real power is considered. Net load is calculated (in MW) for each node (by subtracting production from consumption) and the resulting surpluses/shortages are assumed to be transported between the nodes. The influence of elements such as reactive power, voltage and frequency control, is ignored. If there is a net load difference of 1000 MW between two regions, the model thus assumes that this will create a 1000 MVA load for the grid segments connecting these nodes.

Limitations

To summarize the consequences of the modeling assumptions as well as the verification and validation results, the following model limitations should be observed during its use:

- The model calculates static outcomes for one hour, on the basis of supplied data on external factors (e.g. fuel costs). It can thus not be used to simulated an extended period of time.

- Congestion costs are assumed not to affect the demand for electricity of consumers.
- Results should not be relied upon for network planning decisions. Actual power flows will deviate from those calculated by the model, given the nodal approach, rough PTDF calculations, and assumption "MW = MVA".
- The model will return unreliable results (and will not return an error) when made subject to conditions that result in a physical supply shortage.
- The algorithm used to simulate the application of the market coupling does not function optimally and requires manual intervention during simulation runs (see Appendix C.3.4).

4.7 Model performance

The main reason for constructing a simulation model during this study was to quantify the effects of applying different congestion management methods in the Netherlands. From a theoretical perspective the methods have already been extensively discussed in existing literature, but the quantitative practical insight was still lacking. This section discusses whether, and to what extent, this objective was fulfilled by the model, that has been introduced throughout the current chapter. First, section 4.7.1 will elaborate on the model's ability to capture the Dutch electricity system. Second, section 4.7.2 will evaluate the use of the key performance indicators used during this study, and third section 4.7.3 will discuss the strategic bidding analysis that was made possible by this model. Section 4.7.4 provides an overview of the main principles that were found to be important for modeling studies that deal with the practical application of congestion management methods.

4.7.1 Application to the Netherlands

A simulation model can contribute to assess the practical value of a theoretical concept by providing a means to get an insight in the outcomes of applying it in reality. If simulation outcomes differ from theory, this indicates that either the theory is invalid (or incomplete), or that the conditions the real-life situation is subject to are not in line with the assumptions on which the theory is based. The latter result would imply a limitation to the circumstances under which the theory is valid. The theoretical concepts of the different available congestion management methods have been extensively discussed in literature (e.g. Brunekreeft et al. (2005), Copenhagen Economics (2006), Ehrenmann & Smeers (2005), Leuthold et al. (2008), Pérez-Arriaga & Olmos (2005)), but with the exception of *system redispatch with cost pass-through to generators* (Hers et al., 2009b) they have not yet been tested for their application in the Netherlands. Therefore, the objective of constructing a simulation model during this study was to gain an insight into the effects of applying these theoretical concepts – congestion management methods – to the (existing and real) electricity system of the Netherlands. This allows for an assessment of whether the outcomes that would be expected on the basis of theory, actually hold in reality. Also, it enables the quantification of these expected effects, for the Dutch situation specifically.

4.7.2 Use of KPIs

The quantitative effects of the congestion management methods were captured by four key performance indicators, which were presented in section 3.3. The use of these, which are listed below, is discussed in the current section.

- Extent of congestion (measured by ECI)
- Congestion cost (and allocation) (measured in € / h)
- Incentives (qualitative assessment)
- Market concentration (measured by RSI)

Congestion cost and incentives

The indicators *congestion cost* and *incentives* are rather straightforward and were a great aid in evaluating the congestion management methods.

Extent of congestion

Measuring the *extent of congestion* using the Extent of Congestion Index, an indicator that was constructed during and for the purpose of this modeling study, produces a figure that, even though it is crystal clear in definition, is not yet specified to have interpretative value. Given the capacity that needs to be redispatched to a downstream congestion zone, it indicates how much capacity of the still-available units needs to be dispatched in order to solve congestion. However, a theoretically substantiated framework that allows to put the quantitative outcomes in perspective is still absent. This would be required in order for the values to have interpretative value, as it is still unclear what the difference in consequences is of, say, the indicator scores 10%, 20%, or 80%: how much worse a score is one compared to the other?

Nonetheless, the ECI can be considered a useful indicator that reveals the transmission capacity-aspect of the problems that could arise from short-term congestion: capacity needs to be redispatched from one area to the other, and the less capacity there is available to do so, the greater is the need for additional transmission capacity. An inherent shortcoming of the indicator is that it does not relate to the very nature of congestion, but only indicates how problematic it is to mitigate the consequences. Congestion arises because the capacity of the transmission infrastructure cannot cope with the amounts of excess generation (or load) in one location, that need to be transported to the other. The ECI indicator, however, is not related to these factors, but merely indicates whether, and to which extent, the problem can be solved by means of redispatch.

Market concentration

The fourth indicator used to evaluate congestion management methods deals with *market concentration*. The Residual Supply Index can be used to measure the dominance of individual generators in a market, on the basis of their available production capacities. It is not specifically meant as an indicator for dealing with the issue of congestion, but it can provide a useful insight in market competitiveness under congestion. Market competitiveness is particularly important under congestion, because some congestion management methods (market splitting, market coupling, APX-based method) divide the market into regional sub-markets –either only in the case of congestion or permanently– which decreases their size. Market players that did not have a dominant position on the (uniform) market as a whole, may be presented with opportunities to artificially influence their smaller, regional market that was created as a result of congestion. In this case it would make no sense to only assess market concentration on a national level, because these new regional opportunities would not be detected. By calculating RSI values for the different congestion zones and at a nodal level, this effect can be incorporated.

In short, although RSI is in itself not an indicator related to congestion, it can be applied as a congestion management method indicator. Different methods lead to different zonal layouts, each of which causes different RSI values.

4.7.3 Strategic bidding and development over time

One of the objectives of this study is to identify the opportunities for and quantify the potential consequences of generators bidding bidding strategically. As was discussed before (see section 4.2.2), strategic bidding analysis comprised a separate element of this study and strategic bidding behavior of generators was not fully incorporated in the model. This would have required a more extensive, agent-based model, that is able to simulate the behavior of all producers and their individual motives, with respect to e.g. submitting offers and investment decisions, separately. The time and resources available for this project, however, were insufficient for the construction of a model of this kind. Note that this is also caused by the requirement that such a model would need to simulate the electricity system over a longer time horizon (e.g. 8760 separate hours per year, for the duration of several years), but this kind of model was already discussed in section 2.5 to fall outside scope and time constraints.

The scope definition which excluded the modeling over time has resulted in limited application value of the model. The insights that were found by obtaining values for the KPIs (see Chapter 6) that were defined are not fully conclusive, in the sense that they are only applicable for the narrow set of conditions that formed the input factors for simulations. Because these input conditions change frequently –even hourly– conclusions with respect to a period of e.g. a year cannot be drawn and extrapolating the results is utterly impossible. However, the model does provide an insight into the consequences that the presence of the conditions assumed in these four extreme scenarios would cause. Given that only the very extreme scenario conditions lead to significant consequences with respect to congestion (see Chapter 6), the model provides useful insights despite these limitations.

Use by generators

During strategic bidding analysis the model was used to determine the extent to which individual generators could game the system in order to increase their profits. It would therefore also be a useful tool for generators to use in reality, because it would enable them to find out how they can maximize their profit under the particular conditions that are present. Needless to say, the model was not constructed to be used for this purpose, but the mere fact that it has the ability to be used as such can be considered as a strength of the model nevertheless.

4.7.4 Four modeling principles

The separate modeling of all generators was found to be a very useful approach during this study. A more extensive, future modeling study could be based hereupon, although it should additionally incorporate individual generator behavior with respect to their offer submitting strategies and their development over time). Furthermore, such a model could be combined with the more detailed transmission network model that is currently under development by TenneT. This would allow for the creation of a model that incorporates a wide variety of electricity system aspects and is able to not only capture the effects of applying different congestion management methods, but which can also be used to simulate the consequences of transmission system expansions (or the lack thereof), interconnection developments, and the variable supply of electricity from intermittent sources. Of course, this all depends on what is found to be sufficiently relevant to include in the model and what is not.

To sum up the current section (4.7), this modeling study has resulted in four modeling principles[26] which were found to be useful and important for the simulation of the practical application of congestion management methods. Their consideration is advised for subsequent electricity system modeling studies:

- Analysis at the level of separate producers, each with a unique set of units at their disposal
- Modeling a real and existing situation (i.e. not a purely theoretic evaluation), with particular characteristics (using real data)
- Adaptive profit-maximizing bidding behavior *(currently not included)*
- Dynamic model (simulating for the duration of a longer period), which allows for learning effects and investment decisions to be captured *(currently not included)*

26 Note that not all of these principles were incorporated in the model that was constructed during this study. This is indicated in the bulleted overview.

5 Model use

In order to obtain meaningful results the simulation model was run under different scenario conditions. Four scenarios were constructed, in addition to a 'base case' reference scenario. These are presented in section 5.1. Whenever the scheduled flows would lead to congestion after running the model under particular scenario conditions, the performance of all four congestion management methods (see section 3.2) was evaluated, i.e. the model was run four times using the different mechanisms. This process is described in section 5.2. Lastly, it is important to note that some factors – such as network losses and network safety – fall outside the scope of this study. Section 5.3 discusses the assumptions that lie at the basis of each simulation run.

5.1 Scenarios

This section presents the four scenarios that were simulated during this study, in addition to the base case scenario. Each scenario is briefly introduced by means of a storyline which qualitatively describes the scenario conditions that are assumed during the model run. All scenarios are constructed for the year 2016. Please refer to Appendix G for a discussion on the relevance of each of these scenarios for this study. In addition Appendix G provides an overview of the quantitative model implications of these scenarios, i.e. the parameters (e.g. fuel price, wind factor) that attain a value different from the base case scenario.

5.1.1 Scenario 1: Low wind availability in Germany



A large increase in production capacity has turned the Netherlands from a net importer into a net exporter of electricity. As a result of the completion of new production capacity, prices in the Netherlands are now structurally lower than in Germany when wind availability is low. Because the markets are coupled, electricity can easily flow from low price to high price areas, thus creating flows in the direction of the latter. Although lower than in Germany, electricity prices in the the Netherlands still fluctuate around the same level as prices in the United Kingdom. This leads to a situation where the power flow in the BritNed interconnector is frequently reversed, which has important implications for the connection between the Maasvlakte and the Ring. The power flows imposed on the lines connecting these nodes easily vary by up to 2000 MW (from 1000 MW in one direction to 1000 MW in the other) due to the direction of the power flow in this line. This scenario assumes high wind availability for British off-shore wind parks, resulting in British prices to drop below those in the Netherlands.

5.1.2 Scenario 2: Cheap natural gas

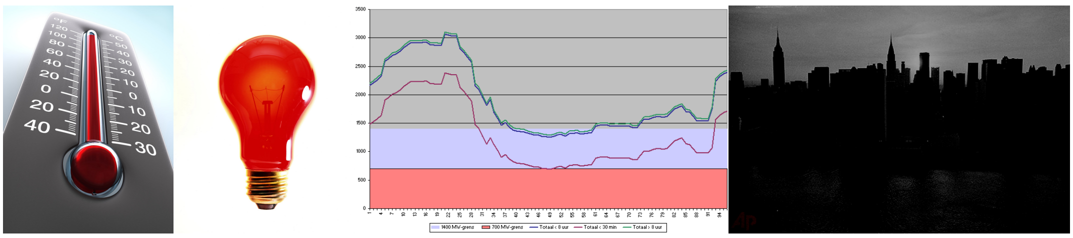



Several large discoveries of oil and gas fields around the world have significantly driven down the prices of these fuels, which results in gas fired plants having become cheaper than those that run on coal. Producers rather dispatch a gas fired plant now their marginal costs have dropped below those of coal fired plants, and are supported in this decision by the national government which hopes to reduce carbon emissions by the increased usage of gas rather than coal. The depletion of oil and gas fields that was once considered a major problem is no longer an issue now that new sources are commercially viable to be exploited. Despite warnings from the academic community that the current abundant availability of oil and gas by no means implies the existence of sufficient long-term reserves is neglected as people enjoy the short-term economic advantages of the recent discoveries. Because of the environmental advantages that natural gas has over coal, the call for stringent emission reductions is no longer present with a majority of society and politicians. Although the European emission rights trading system is still in place, the cost of a CO_2 emission right is at an almost record low. And hardly anyone cares.

5.1.3 Scenario 3: Green Revolution

Despite a temporary drop in 2009 due to the worldwide economic crisis, prices of fossil fuels have continued to climb. This has made investment in renewable energy sources more attractive, although the main driver behind the investments originated from increased attention and support from the Dutch national government. An era of *Green Revolution* has begun and has led to several major wind parks in the North Sea. There is consensus among government, population, and environmental organizations that offshore wind parks are the best option to mitigate climate change and (foreign) fossil dependency in a country as densely populated as the Netherlands. These wind parks do, however, create additional transmission needs which cannot always be met by the current grid. In total 900 MW is fed into the Dutch transmission grid at the Eemshaven (node NN), 1513 MW in the province Noord-Holland (node RN), and 775 MW in the province Zuid-Holland (node MV). Transmission capacities between Eemshaven / Maasvlakte and the Ring have not been increased and thus remain in their 2015 state.

5.1.4 Scenario 4: Code Red



An exceptionally hot summer has caused temperatures of inland waters such as rivers and canals to rise above 23°C. In order to prevent exceeding the maximum temperature thresholds set to protect the environment, several power plants are forced to shut down. Thermal power plants heat up the cooling water they use by approximately 7°C and thus exceed the maximum allowed cooling water release temperature of 30°C. Available reserve capacity is down to 200 MW and TenneT proclaims a code red situation, because there is a serious risk of physical power shortages to arise as a result of demand exceeding supply. Consumers of electricity do not appear to respond to the code red situation and continue to use power as they would normally do.

Furthermore, the scenario assumes that similar cooling water problems have arisen in Germany which has resulted in an old gas fired plant being the marginal unit.

Because all units that are shut down are located at non-coastal locations (node RN and ZL) and use rivers and lakes as a heat sink, power flows from coastal areas (nodes NN and MV) increase to serve the load. Wind availability is very low so the wind farms connected to node RN cannot mitigate the drop in supply. Plants located near the coast (particularly Maasvlakte and Eemshaven) are not affected, as they can continue to use the (colder) North Sea water for cooling.

5.2 Congestion management methods: simulation runs

If the conditions assumed in a scenario lead to congestion when the simulation model is run, all four congestion management methods are (separately) applied to solve this congestion. This creates an opportunity to gain an insight in both the methods themselves, as well as the potential differences when applied in varying circumstances.

The application of these methods results in an adjustment in the *Market* sub-model, which now needs to distinguish between demand and supply in the congested region and the other, uncongested regions. Also, the *Dispatch* sub-model will converge to a different dispatch pattern, because it now needs to take into account the physical location of the production units. The *Transmission* sub-model continues to function as before, as this model element merely uses the aggregated information from both the former sub-models to calculate the resulting flows. If congestion is detected on the basis of the new scheduled flows, another iteration is required because the connection between another pair of nodes could have become congested as a result of solving the first instance.

5.3 Simulation assumptions

This section briefly lists the assumptions that all simulation runs were subject to.

- **Perfect competition:** All simulation runs assume that generators bid at competitive levels, at the basis of true variable costs and offering all available capacity. Situations where market power is exerted by generators are analyzed separately and are discussed in section 6.3.
- **Network safety:** Line utilization rates indicate scheduled, thus not actual, flows, and power line capacities used by the model have been adapted to incorporate safety margins. If the model indicates that a line is 100% utilized, this should be interpreted as that this load can be transported within operational, safety and reliability margins. A utilization rate of 100% thus does not indicate that the absolute thermal limit of the line is reached, but rather that power transports are at the maximum acceptable levels (and N-1 safe). The objective of congestion management is thus to reduce scheduled line utilization to 100% (or smaller, but this would generally be economically inefficient).
- **Supply offers at equal price level:** When there are multiple suppliers that offer capacity to the market at MCP, the simulation model assumes that the largest offers (in MW) are accepted first, until the volume meets demand. This approach is deemed more realistic than accepting a proportion of all offers, because this could lead to all marginal producers to be required to dispatch units at inefficient production levels. The marginally accepted offer may, under this approach, require one generator to dispatch its marginal unit at an inefficient production level, but the consequences resulting from this are ignored. Note that the marginal suppliers do not make a profit when their offers reflect true cost of production, so this will not affect any generator, neither positively nor negatively, in the surplus calculations.

6 Simulation results

This chapter presents the simulation results for the scenarios that were discussed in section 5.1, including the effect these have on the KPIs that were defined in section 3.3. Section 6.1 discusses the congestion sensitivity of the four different regions that are distinguished by this study. Section 6.2 deals with the congestion costs – and their distribution – that arise because of the application of different congestion management methods, and the incentives that these provide to generators to mitigate (or benefit from) congestion. The possibilities for generators to exert market power by bidding strategically are discussed in section 6.3, which presents the results of the analysis that was performed to quantitatively analyze the extent of the benefits that generators could gain by bidding strategically under the different congestion management methods. Section 6.4 will present the conclusions from the simulation results.

6.1 Region congestion sensitivity

The sensitivity of regions to become congested was determined on the basis of the Extent of Congestion Index (ECI) (see section 3.3.1). The ECI provides an indication of the extent of congestion on the basis of the capacity that needs to be redispatched as a proportion of the capacity available for redispatch. The scores for the four scenarios (in addition to the base case scenario) are shown in Table 6. Please note that two or more nodes may form a combined congestion zone, in which no congestion arises internally. In such a situation the ECI-value for each of the nodes separately is considered equal to the ECI for the zone as a whole, to reflect the fact that it does not matter *where* capacity is dispatched as long as it is dispatched somewhere in the zone.

ECI	Node 1 / NN	Node 2 / RN	Node 3 / MV	Node 4 / ZL
Scenario 0: Base case	0.00% (no congestion)			
Scenario 1: Low wind in DE	10.58%	10.58%	0.00%	10.58%
Scenario 2: Cheap gas	0.00% (no congestion)			
Scenario 3: Green revolution	0.00% (no congestion)			
Scenario 4: Code red	0.79%	0.79%	0.00%	0.79%

Table 6: Extent of Congestion Index values

The first and probably most striking conclusion is that the overall extent of congestion is rather small. Although the four scenarios were designed to include extreme conditions, congestion only occurs under two of them. Only in case of large power flows in the eastbound direction, which is the case under scenario 1 where the Netherlands is assumed to export 6,000 MW to Belgium and Germany while BritNed feeds into the Dutch grid (at the Maasvlakte-node) at full capacity (1,000 MW), a significant amount of congestion occurs. Under these scenario conditions 1292 MW needs to be redispatched from the Maasvlakte to a different part of the country in order for power flows to remain within transmission limits. There is sufficient capacity available to do so: only 10.58% of non-dispatched production capacity needs to be called on in order to solve congestion.

Congestion under scenario 4, in which the availability of production capacity in the nodes RN and ZL is drastically reduced as a result of cooling water restrictions, remains limited to 59 MW that needs to be redispatched from the Maasvlakte to another part of the country. The low ECI-value (0.79%) for the area downstream of congestion indicates, however, that there is plentiful capacity available to deal with the redispatch requirements.

The flows that are scheduled on the basis of market transactions under scenarios 2 and 3 can be physically implemented without restrictions.

6.2 Congestion costs and resulting incentives

There is a close relationship between congestion cost distribution and the incentives that follow from applying a congestion management method. The distribution of congestion costs essentially determines whether market parties are "rewarded" or "penalized" for their actions, by increasing or decreasing their surpluses. These incentives are evaluated from a transmission system efficiency perspective, i.e. they are considered "wrong" if they provide an incentive to maintain or increase congestion. From other perspectives these incentives may be valued differently. For instance, the location of a new power plant is not only evaluated by its transmission system efficiency, but also whether it is constructed nearby population areas (by the public) and whether it has reliable access to fuel sources (by the generator). Section 6.2.1 provides an overview of the congestion costs and their distribution, that result from the application of the different congestion management methods, and 6.2.2 discusses the incentives that result from this distribution.

6.2.1 Congestion costs

As was discussed above, only two out of four scenarios resulted in a situation in which the scheduled flows would cause congestion on the transmission grid. Both these scenarios, *Low wind availability in Germany* (scenario 1) and *Code Red* (scenario 4), were used to simulate the application of the four congestion management methods. The results are discussed below, separately for the scenarios.

Under the base case scenario there is no congestion (hence, congestion costs are € 0). The nation-wide applicable RSI value equals 154%. Scenarios *Cheap natural gas* (scenario 2) and *Green Revolution* (scenario 3) did not result in congestion either. The (nation-wide) RSI values under these scenarios are 154% and 182%, respectively.

Scenario 1: Low wind availability in Germany

In order to solve the congestion that arises in the grid between the Maasvlakte and the Ring, which is created by large eastbound flows, a volume 1292 MW needs to be redispatched. Although the amount of power is large, the resulting congestion cost remains limited. As Table 7 shows, the total cost of solving congestion in this situation is only € 231, which would on a yearly basis – that is, if these scenario conditions were to be present during every single hour of the year – amount to a congestion cost of € 2 mln., and on a per-MWh-basis[27] it is € 0.18.

This cost arises from sub-optimal dispatch of units. However, as the variable cost difference between the units that are regulated down in the upstream area of congestion and those that provide compensatory power in the downstream area is small (in fact, most production units generate electricity at the same cost level), the total unit dispatch cost difference is almost negligible.

Congestion cost Scenario 1	**BSR**	**MS**	**MC**	**APX**
Consumers			€ 1,258	
- NC zone	€ 0	€ 1,258		€ 0
- C zone	€ 0	€ 0		€ 0
Producers			€ 5,305-	
- NC zone	€ 0	€ 5,305-		€ 231-
- C zone	€ 0	€ 0		€ 0
TenneT				
- National	€ 231-	€ 4,792	€ 4,792	€ 0
- International	€ 0	€ 975-	€ 487-	€ 0
National SW	**€ 231-**	**€ 231-**	**€ 256**	**€ 231-**
Foreign TSOs	€ 0	€ 0	€ 487-	€ 0
Total SW	**€ 231-**	**€ 231-**	**€ 231-**	**€ 231-**

Table 7: Congestion cost distribution under scenario 1 (in € / hr)

27 Total congestion cost (€ 231) divided by the congested capacity (1292 MW).

Although the total effects on social welfare are limited, the different congestion management methods cause larger differences with respect to the distribution of welfare among society. This is shown by Table 7, which indicates benefits and losses for different stakeholders that may be more than 20 times larger than the total welfare effects. When market splitting or market coupling is applied, generators face a surplus loss equal to € 5,305, whereas consumers (+ € 1,258) and TenneT (+ € 4,792; considering internal congestion rents only) experience an increase of surplus. Basic system redispatch and the APX-based method do not create these large fluctuations in surplus among society. Under these methods the social welfare loss is directly allocated to a single (type of) stakeholder.

Market concentration	Residual Supply Index (RSI)
Netherlands	154%
Not-congested region	404%
Congested region	130%

Table 8: RSI values under Scenario 1: Low wind availability in Germany

Table 8 shows the degree of market concentration for the Netherlands as a whole and for the separate congestion zones that were distinguished under basic system redispatch, market splitting, and the APX-based method. Note that these also apply for market coupling, although the method considers these nodes separately. Under market coupling the connection between MV and RN is fully used and cannot accommodate additional transports, which *de facto* results in the same two price zones as under the other congestion management methods.

Scenario 4: Code Red

The extent of congestion under the *Code Red* scenario is limited: only 59 MW must be regulated down in the Maasvlakte area and redispatched in another part of the Netherlands. Because there is no difference in variable cost between the initially scheduled and redispatched units, congestion cost is equal to zero as is shown by Table 9. Note that in reality a small difference would be likely to exist between the variable costs of these units, which would create some congestion costs after all. These would be distributed in a manner similar to the costs under scenario 1 shown in Table 7. However, these costs are likely to be small and only the result of slight unit efficiency differences. If large congestion costs could be expected, this would be the result of the dispatch of a different type of unit and would have shown up during the simulations results below.

Congestion cost Scenario 4	BSR	MS	MC	APX
Consumers			€ 0	
- NC zone	€ 0	€ 0		€ 0
- C zone	€ 0	€ 0		€ 0
Producers			€ 0	
- NC zone	€ 0	€ 0		€ 0
- C zone	€ 0	€ 0		€ 0
TenneT				
- National	€ 0	€ 0	€ 0	€ 0
- International	€ 0	€ 0	€ 0	€ 0
National SW	**€ 0**	**€ 0**	**€ 0**	**€ 0**
Foreign TSOs	€ 0	€ 0	€ 0	€ 0
Total SW	**€ 0**	**€ 0**	**€ 0**	**€ 0**

Table 9: Congestion cost distribution under scenario 4 (in € / hr)

The RSI values under the *Code Red* scenario are shown in Table 10. The decreased availability of production capacity in the RN and ZL nodes, which are part of the congested (downstream) region, is reflected in the lower RSI values nation-wide, but particularly in the congested region itself. These are down from 154% in the base case scenario.

Market concentration	Residual Supply Index (RSI)
Netherlands	137%
Not-congested regior	404%
Congested region	115%

Table 10: RSI values under Scenario 4: Code Red

Congestion cost allocation – discussion of simulation results

The simulation results that were presented in the current section have primarily shown that the societal welfare loss (i.e. the net congestion cost) is small. Under the *Low wind availability in Germany* and *Code Red* scenarios the marginal cost of production in both the regions upstream and downstream from congestion is equal or nearly equal, and because the supply curve shows a gentle slope around the intersection point as a result, a sufficient volume can be redispatched without having to dispatch units that are much more expensive. In fact, the (small) congested volume under the *Code Red* scenario can be fully alleviated by *constraining off* and *constraining on* plants at an exactly equal[28] cost of production, which leads to congestion costs of zero. Note that the Netherlands, under the *Code Red* scenario, effectively remains a single price area, despite the fact that there is congestion. This is also the case when market splitting or market coupling is applied – in spite of the main characteristic of these methods being that they alleviate congestion, and implicitly auction the available transmission capacity, by creating different price zones.

To comprehend this situation one must understand how these methods deal with congestion. By including an additional price-independent component to the demand/supply curves, the intersection point on these curves is shifted to a new price/volume-pair. However, the stepwise nature of electricity supply curves makes a situation possible in which the intersection point is shifted, but ends up at a point of equal MCP. In such a situation congestion is solved without altering the MCP.

The simulation results further show that total welfare loss (i.e. congestion costs) is equal under all methods. All methods are thus able to alleviate congestion in a short-term efficient manner. This is consistent with earlier work of De Vries & Hakvoort (2002), who came to the same conclusion on the basis of a theoretical analysis of five congestion management methods, similar to those evaluated in the current study. The long-term effects of the methods are not the same, given their distributive effects. This is discussed in section 6.2.2.

6.2.2 Incentives

As was observed in section 6.2.1, all congestion management methods that were evaluated resulted in the same net effect on social welfare. Regardless of the congestion management method applied, there was a net societal congestion cost of € 231 under the *Low wind availability in Germany* scenario and € 0 under the *Code Red* scenario. The allocation of congestion costs to the different stakeholders did, however, differ with the application of different methods. Because each method leads to different stakeholders that are affected (to a different extent), the methods provide different incentives for changing behavior with respect to electricity production and consumption, which – considering that short-term price elasticity is low, as was argued by Ackermann (2007) – might affect production, consumption, and, as a consequence, transmission patterns in the longer term. This section discusses the long-term effects that could be expected with respect to electricity production and consumption patterns in the Dutch electricity system under the different congestion management mechanisms.

Basic system redispatch

The responsibility of solving congestion under the basic system redispatch method resides with the TSO. The scheme aims to minimize the disturbance to market players whenever congestion affects the feasibility of their transaction patterns. It achieves this by not involving consumers in the congestion management scheme at all, and by only involving generators to the extent that they are absolutely necessary to solve congestion (i.e. by constraining off some capacity and constraining on compensatory power). The scheme maintains a uniform pricing scheme, which causes insufficient incentives to be created for “favorable location of production and consumption” (Bjørndal & Jörnsten, 2007, p. 1980)[29]. Generators required for alleviating congestion are

28 These were calculated to be “exactly equal” on the basis of extensive, but not entirely complete variable cost estimates. It is almost inevitable that small variations between generation units will cause differences to exist, but on the basis of these modeling results they can be expected to be very small.

29 Note that Bjørndal & Jörnsten (2007) evaluated counter trading, rather than basic system redispatch. The

reimbursed for the costs this creates for them, without creating any incentives whatsoever. This also holds for the other generators as well as consumers, as these are not involved in the congestion management scheme at all.

The congestion costs that arise from applying basic system redispatch are all allocated to TenneT. This provides it with an incentive to improve grid capacity (Bjørndal & Jörnsten, 2007). However, as a congestion cost of € 231 per hour would amount to approximately € 2 mln. on a yearly basis, grid investments are unlikely to be economically efficient, especially if one takes into account the fact that the simulated scenario conditions are very unlikely to be present during every single hour of the year. Although additional research, in which the occurrence of such scenario conditions would be quantified, is required to provide an accurate estimate of actual total annual congestion costs, it seems unlikely that basic system redispatch will provide an incentive to any party to solve congestion. It appears to be cheaper for TenneT to bear the congestion cost of € 2 mln. (if in fact that high) than to invest in the grid. Other stakeholders are not financially affected by congestion and have therefore no incentive to adapt their behavior as a result of congestion.

Despite the fact that congestion costs are probably too small to make grid investments economically efficient, tariff structure regulations could potentially trigger economically inefficient actions. TenneT is currently allowed to transfer the cost of investments in the grid infrastructure to consumers, insofar as these investments are held to be efficient by the regulatory authority. For congestion costs this is only possible in case of non-structural congestion. This creates an incentive for TenneT to invest in grid capacity, because this cost can be recovered whereas (structural) congestion costs cannot. If grid expansion is economically efficient, compared to accepting occasional congestion costs, basic system redispatch provides the right incentive: congestion, indicating a shortage in transmission system capacity, must be solved by the TSO by expanding this capacity. However, if expanding the grid would turn out to be economically inefficient, as is suggested on the basis of the modest height of congestion costs, and regulations do not allow to pass on the cost of congestion to consumers, TenneT would be provided with an incentive to take sub-optimal action from a net societal welfare perspective. This will be further discussed in section 7.1.

Market splitting

Although having the same net effect on total social welfare, market splitting creates both large benefits and losses for different stakeholders. The small total cost of congestion is transformed into separate components which show fluctuations that are much larger than the total cost itself. Simulations of its application have shown that when applied in the Netherlands, market splitting will primarily transfer wealth from producers in the Maasvlakte region, which has an excess of production capacity, to consumers in the same region and to TenneT, which would benefit from inter-zonal trade.

Market splitting producers with an incentive to decommission inefficient capacity and to not invest additionally in the area, whereas consumers could benefit from locating energy-intensive industries in this area (which also relieves congestion). These findings are in line with Bjørndal & Jörnsten (2007), who discuss that the different welfare effects created by the method provide incentives to market parties for efficient behavior. They also discuss the perverse incentive that is created for TSOs, which would also exist in the Netherlands as simulation results have shown. TenneT financially benefits from congestion in the Netherlands and therefore has no incentive to invest in grid capacity as alleviating congestion would dry up its revenue stream.

In order to mitigate this disincentive, the Office of Energy Regulation could lay down that all congestion rents are invested in the transmission system. However, if the cost of investment outweighs the actual societal cost created by congestion (which was found to be small), it would be socially inefficient, and thus undesired, if the TSO would heavily invest in transmission capacity, only to mitigate these small costs.

methods share the same characteristic of maintaining a uniform pricing structure, however.

Alternatively, Bjørndal & Jörnsten (2007) and Kristiansen (2007b) mention that these revenues could be used to lower transmission tariffs. This would keep the locational incentives intact, while not providing a disincentive to the TSO. It is relevant to point out that this would effectively result in a transfer of wealth from generators to consumers in the Netherlands, as currently only consumers must pay for transmission tariffs. Transferring congestion rents to consumers may therefore be appropriate if transmission costs are created by generators that solely produce electricity for export purposes. However, it falls outside the scope of this study to determine what transmission pricing structure is most desirable for the Netherlands.

Market coupling

Under the market coupling mechanism a welfare and incentive distribution will be created that is in principle similar to market splitting. A difference arises because of the assumption that the market coupling scheme will be incorporated in the European market coupling mechanism, rather than market splitting, which is assumed to be applied only *after* transmission flows are determined on a European level. This makes congestion a national issue under market splitting. Considering the excess capacity and resulting lower MCP in the Maasvlakte area, market coupling versus market splitting results in a benefit for TenneT because it no longer needs to compensate a foreign TSO for decreased congestion rents (compared to the situation in which the Netherlands were to be considered as one market with a uniform price) with respect to trade with the United Kingdom over the BritNed cable.

APX-based method

The APX-based method allocates the cost of congestion at the expense of generator revenues, while maintaining a uniform price approach for consumers. Generators in an area with excess capacity are therefore not compensated if they are *constrained off*, while the cost of acquiring compensatory *constrained on* power is allocated to not-*constrained off* generators up to the extent that the most expensive producer can still cover its variable cost of production. Because this potentially creates a cost for being located in an area with excess capacity, both for generators that are constrained off (because they are not compensated) as well as those that are not constrained off (because they receive a smaller MCP if compensatory power comes at a cost above MCP), it creates an incentive for generators to be located outside the upstream congestion area. TenneT only faces a cost if the cost of production in the upstream area is relatively high, because in this case it cannot fully transfer the cost of *constrained on* power to generators upstream and must itself bear a part of these. Consumers are not financially incentivized at all under the scheme.

Simulation of the application of the APX-based method has shown that the marginal cost of production in the areas both upstream and downstream from the congested infrastructure are similar. Even when 1292 MW needs to be redispatched, no cost is involved for TenneT because it can acquire sufficient power at MCP and does not need to compensate the generators that are *constrained off*. More than 3200 MW of congestion would need to arise before TenneT could expect to need to bear some of the cost arising under the APX-based method (see Appendix I.2.5), from which one can conclude that the method will in practice primarily create an incentive for producers in the Maasvlakte area, which has excess production capacity in place.

Although the method was developed internally by TenneT and as such is not discussed in existing literature, it is basically a combination of two known concepts. It maintains a uniform pricing approach for consumers, while creating locational incentives for generators. However, these locational incentives are much smaller than under market splitting and market coupling. This is caused by a core difference between these methods with respect to determining which generators are *constrained off* and which are *constrained on*. Market splitting and market coupling only provide price signals, which must be large enough for a sufficient volume to respond. The APX-based method, on the other hand, specifies the volume that must be redispatched and directly designates which generators must be *constrained off* and *constrained on*. Although the cost of this process is transferred accordingly, it has no influence on exactly which generator is affected.

Under the APX-based method the height of the price signal is thus not required to ensure that a sufficient volume is involved to alleviate congestion, unlike is the case with market splitting and market coupling. As a result, the cost that is incurred by upstream generators solely reflects the real cost of redispatch. The APX-based method could therefore be categorized as a variant of counter trading as discussed in existing literature (e.g. Bjørndal & Jörnsten (2007), Kristiansen (2007b)), but with congestion costs transferred from the TSO to the upstream generators[30]. The incentive to resolve congestion therefore resides with these generators, which discourages it from investing in new capacity. This incentive is very small, however, considering the small cost of congestion that would arise.

6.3 Strategic bidding

Section 6.2 presented the results of applying different congestion management methods with respect to the congestion costs they create and whom these are allocated to. At the basis of these quantitative results lay the assumption that all generators bid at competitive levels. In reality, however, this may not necessarily be the case when producers seek to increase their revenues by bidding strategically. Hakvoort et al. (2009) and Hers et al. (2009b) argue that strategic bidding by generators has potentially serious consequences for congestion costs and the distribution thereof, especially because, according to Hers et al. (2009b), strategic bids that deviate up to 10% or 20% from competitive bidding levels would go unnoticed by the regulatory authority. To quantify the potential consequences of strategic bidding behavior under congestion, several business cases were designed in which one or more generators seek to increase their revenues by bidding strategically. The most important results of this analysis, which can be found in their entirety in Appendix I, are discussed below.

6.3.1 Approach

The aim of this market power analysis is to gain a quantitative insight in the consequences that strategic bidding may have for congestion cost if generators would actually exert their opportunities. Theoretical knowledge on such opportunities already exists, but it is unclear whether, and to what extent, strategic bidding can actually be applied in the specific case of congestion arising in the Netherlands. The approach of this analysis therefore consisted of the construction of a number of “business cases”, in which generators that, on the basis of theory, have an opportunity to bid strategically in order to increase their profits, were assumed to actually pursue such strategies. These strategies were modeled to obtain quantitative outcomes on the consequences with respect to the extent of congestion and the distribution of the (potentially) resulting cost.

6.3.2 Business cases

Five business cases were constructed and simulated in order to perform this analysis. These are listed below. Note that this is not an exhaustive list of bidding strategies, considering that the analysis did not take into account the fact that multiple generators may bid strategically at the same time and that the strategies were based upon the possibilities that presented themselves under specific scenario conditions. Also, generators have a continuous range of possibilities available in reality for determining their precise bid levels, both in terms of price and volume. As such, it would be impossible to simulate the practically infinite range of bidding strategies imaginable. The results should therefore primarily be interpreted as having an indicative value. To obtain a full insight into the consequences of strategic bidding, an agent-based model would be required that is able to capture the strategies of all individual generators, under the variable scenario conditions that are in reality present over an extended period of time.

- Constrained off bids below actual avoided cost under basic system redispatch
- Scheduling inefficient capacity under basic system redispatch
- Deliberate withholding of capacity to become constrained on under BSR

30 Up to a maximum extent, depending on the highest accepted upstream offer. See the first paragraph of this sub-section.

- Price inflation by withholding capacity under market splitting
- Capacity withholding and offer inflation under the APX-based method

Please refer to Appendix I for a complete description of each case.

6.3.3 Criteria for assessing strategic bidding opportunities

Whether or not generators can exert market power and increase their profits by bidding strategically and the consequences of this is assessed on the basis of the following criteria:

1. Obtainable generator strategic bidding revenue
2. Increase of (societal) congestion costs (i.e. decrease of Total Social Welfare)
3. Costs for TenneT

The first criterion determines the profit that a generator can obtain by bidding strategically. If no profits can be obtained from bidding strategically, it is unlikely that such behavior will take place. The second criterion, dealing with the societal costs from strategic bidding, determines the total loss in welfare that will be experienced by society as a whole when a generator submits strategic bids. This loss follows directly from the sub-optimal scheduling of units, because a mere shift of profits would not lead to a difference in *total* social welfare, as this would also include generator surplus. Third, the cost of strategic bidding for TenneT is evaluated. As a TSO with the responsibility to guarantee secure and reliable electricity transmission, which includes dealing with congestion, TenneT bears the risk of being 'milked' in a situation when it has no other option but to shift welfare to generators, if this is necessary to alleviate short-term congestion.

6.3.4 Results

Under competitive bidding the costs resulting from congestion in the Netherlands are expected to be relatively low, as was discussed in section 6.2. Competitive bidding analysis has shown, however, that the opportunities for generators to increase their revenues by bidding strategically are such that congestion costs could increase with an order of magnitude, as is shown in the overview in Table 11. Please refer to Appendix I.2 for a complete overview of the results from the strategic bidding analyses.

Strategy	**Δ Total welfare**	**Generator revenue**[31]	**Cost for TenneT**[32]
Constrained off bidding below var. cost [BSR]	€ 0	€ 5,913[33]	€ 5,913-
Scheduling inefficient units [BSR]	€ 0	€ 384	€ 384-
Capacity withholding [BSR]	€ 1,952-	€ 778	€ 2,730-
Price inflation [MS]	€ 5,270-	€ 12,047	€ 2,091-
Capacity withholding and price inflation [APX]	€ 1,952-	€ 10,791	€ 0
Note that these figures do not necessarily add up to € 0, as not all surpluses (of all stakeholders) are shown.			

Table 11: Bidding strategies and resulting welfare transfers, in € / hr

Note that market coupling was found to yield the same result as market splitting, with the exception that TenneT does not need to ensure that the TSOs of interconnected electricity systems receive an MCP equal to a non-congested situation.

Furthermore, please note that only a limited number of business cases were analyzed during

31 This column presents the revenue for the generator that was assumed to bid strategically.

32 This column shows the additional congestion cost for TenneT that results from generators bidding strategically, i.e. compared to the congestion costs that would result from competitive bidding.

33 This figure results when Intergen is assumed to bid strategically. The same situation was analyzed for Eneco as well, which was found able to game the system for € 2,621 at the expense of TenneT.

strategic bidding analysis. Time and scope limitations prohibited the construction of a model that would be able to determine all strategic bidding opportunities for every generator separately, and as a result these five potential cases were manually detected and subsequently simulated.

6.3.5 Game-theoretic approach

Under the basic system redispatch and the APX-based methods TenneT is responsible for alleviating congestion by making sure that a sufficient volume is *constrained off* in the area upstream from congestion and that a sufficient volume of compensatory power is acquired in the downstream area. TenneT cannot alleviate congestion on its own, but must contract the required volumes from independent generators in order to alleviate congestion. The bargaining process that leads to these contracts is performed through spot and congestion market bids and offers.

Essentially, TenneT issues a contract in which it specifies the product it desires to purchase (*constrained off* or *constrained on* power), which can subsequently be accepted or refused by generators. By bidding into the spot or congestion market generators indicate the price at which they are willing to accept the contract. Because generators have better information on their actual variable costs of production (which determines their willingness to accept this contract at a certain price) than TenneT, an information asymmetry exists which classifies the situation as a principal agent problem (Cunningham, 2008). The principal (TenneT) and agent (generator) have diverging interests, with the former aiming for low and the latter for high prices to be agreed upon. The bargaining position of an agent is strong, as generators know that TenneT *must* eventually accept some of the offers, because otherwise it cannot alleviate congestion, whereas it is not necessary for generator offers to be accepted. On the other hand, competition among generators provides a counter-balance to the playing field.

The game that is played corresponds to the Adverse Selection Game, as is described by Cunningham (2008, p. 66):

> 1. *Nature decides the type of Agent which plays.*
> 2. *The Agent varies in some meaningful, game altering way, which the Principal cannot verify.*
> 3. *The Principal designs and issues a contract.*
> 4. *The Agent accepts or rejects the contract.*

Because *constrained off* and *constrained on* power are homogeneous products, the only bargaining aspect consists of determining the price for this product, which allows for the bargaining process to be greatly simplified and performed on a spot market. Nonetheless, the game could be described as consisting of the steps described above, which can be explained as follows. The type of agent that plays (step 1) is specified by law: all non-renewable generators with capacities above 60 MW must participate. The "meaningful, game altering way" in which agents vary (step 2) relates to differences in variable production cost. The process that is performed at the spot market can be regarded as a direct solution to an otherwise iterative process of repeating steps 3 and 4. Without a spot market, TenneT would design and issue a contract (step 3), asking generators to provide a required volume at a specific cost (note: separately for *constrained off* and *constrained on* power). Every generator can decide whether it accepts or rejects this contract (step 4). By repeating this process using (infinitely) small incremental price steps until sufficiently many generators have accepted the contract to provide the required volume, the game essentially results in the same outcome as the spot market approach: the cheapest generators would be the first to start accepting contracts at some stage in this iterative process, and TenneT continues to play the game until a sufficient volume is acquired.

Note that the presence of this principal agent problem is more widespread under basic system redispatch than it is under the APX-based method. The former includes a game for *constrained off* power, whereas the latter does not. Also, the *constrained on* game is played as an explicit game under basic system redispatch, whereas the APX-based method includes it in the normal spot market trading process. This normal spot market functioning does not classify as a principal agent problem, as TenneT is no party in the trade activities of individual market parties. However, generators may still offer capacity to the normal spot market, only (or partly) for the reason of being included in the principal agent game that is played when congestion arises. Market splitting and market coupling do not introduce a principal agent problem between TenneT and the generators. Although the market process in which consumers and generators decide on prices and volumes also comprises a bargaining situation under asymmetric information, it does not include TenneT as a participant.

6.3.6 Limitations to strategic bidding

Although it is possible that reality shows similar results to those from these hypothetical situations that were analyzed, it is unlikely that costs are this large for two reasons. First of all, Hers et al. (2009b) argue that if generators make use of strategies based on the inflation of offers (or deflation of *constrained off* bids) they can only do so within a range of 10%-20% without being detected by the regulator. Also, the principle of reciprocity applies in reality. Unlike the business cases used in this study, all of which comprised a one-time game, generators will in reality play the “strategic bidding game” over and over again for the duration of many years. During this period they will also have interactions with the TSO, the regulator, their customers, government(s), and each other for many different reasons.

De Bruijn & ten Heuvelhof (2008) argue that in such situations, in which actors operate in a network where their interactions with others are not limited to one-time only but where they will meet again, it is important to consider these future interactions during present-day actions. Thus, even when the regulator cannot legally penalize a generator for its strategic bidding, it could in the opinion of De Bruijn & ten Heuvelhof (2008) negatively affect the relations with other stakeholders and the potential future gains from interaction with them. In order to maintain proper relations with other stakeholders in the network, generators can therefore be expected not to take full advantage of their opportunities to increase profits from bidding strategically, on a structural basis. Unfortunately, this study is unable to provide an answer as to the extent to which generators then *will* increase their profits by bidding strategically. Even if this behavior is curtailed, it could still occur. Fully incorporating this in the analysis would, if even possible, require a highly complex set of actor relations to be included in the model, for which time and means were insufficient.

The second reason why these projections presented in Table 11 are likely to be different in reality is related to a model limitation that is easier to grasp. All of the strategic bidding cases assumed that *only one* generator exploits its opportunities, with all other generators bidding at competitive levels. If other generators also bid strategically, this affects the possibilities and potential revenues for strategic bidding of the generators whose behavior was simulated. Assuming that there is no collusion (i.e. all market players bid individually and may outbid each other), there is thus still a form of competition when generators bid strategically. They must, basically, compete with each other for additional strategic bidding revenues.

6.3.7 Further research

In order to fully understand the behavior of generators when operating in a dynamic environment (i.e. when a generator cannot solely calculate the outcomes of different strategies, but because the outcomes of its strategies depends on the strategies pursued by others) one would need to use a model that can be used to simulate the behavior of all generators when operating in this dynamic environment where everyone's actions influence the outcomes of others' strategies.

6.4 Conclusions from simulation runs

The preceding sections presented the results of a quantitative modeling study into the effects of congestion and the application of four congestion management methods in the Dutch electricity system. Four scenarios, each of which assumed rather extreme conditions, were simulated in order to find out whether and how congestion would affect consumer, producer, and TSO surpluses, with a special focus on the congestion cost that TenneT as the Dutch transmission system operator could expect to arise. This modeling exercise led to various new insights, which are discussed below.

Extent of congestion

Although the four scenarios that were simulated were designed to include extreme conditions which were expected to have a large influence on the unit dispatch pattern and resulting transmission flows, the impact on the extent of congestion in the transmission system of cheap natural gas, large investments in wind farms, or cooling water restrictions for power plants in an area already low on excess production capacity, would be surprisingly low. Only in the case of large eastbound flows, with BritNed feeding in at full capacity (1,000 MW) and 6 GW of exports to Germany and Belgium, a significant amount of congestion arises when 1,292 MW would need to be redispatched from the Maasvlakte to other parts of the country. However, even in this situation there will be plenty of capacity available in the areas downstream of congestion to cover the production that cannot be transported from the Maasvlakte to these areas.

Purely on the basis of the generation capacity/load-ratio, node RN would be vulnerable for congestion. The production capacity available in this node (under base case circumstances) is only slightly larger than its peak load (15,951 MW and 15,363 MW, respectively). Because of the large transport capacities and connections to all other (national) nodes, however, node RN formed a part of a larger congestion zone under all scenarios evaluated and never comprised a single zone by itself. If the node would become isolated from other parts of the system, nearly all generators would be required to meet demand, thus resulting in widespread generator market power under the RSI definition. This situation would be very extreme, however, and would require all transmission connections to other nodes to become unavailable. Because dealing with a situation like this hardly classifies as 'congestion management analysis' (in fact, the isolated node would have no connections that can become congested in the first place) it should be dealt with in the light of general market power research.

Cost of congestion

With the completion of the power plants currently under construction in the Maasvlakte and Eemshaven industrial areas, the slope of the supply curve will be nearly flat in a wide range around the MCP intersection point under peak load conditions[34]. A lot of production capacity will be available to produce electricity at costs that lie within a narrow bound. Together, these units can generate almost 12,000 MW, with a production cost difference of only € 0.97 / MWh between the cheapest and most expensive plants. This holds for both the Maasvlakte area, which was found to usually be the area upstream of congestion, as well as the rest of the Netherlands, which was found to usually be the downstream area[35]. As a result of the similar pricing structures underlying these offers, congestion can be mitigated at a very low cost. Even in case 1292 MW of capacity needs to be redispatched, the total societal cost (€ 231 / hr) is almost negligible and very likely to be low even if the scenario conditions were to be present all year long (€ 2 mln., if extrapolated to 8760 hours). However, depending on the congestion management mechanism applied, the distribution of these costs may create larger differences for different stakeholders, as is discussed below.

Incentives

All congestion management methods were found to be equally efficient in the short-term. They all result in the same net welfare loss. However, the difference in allocation thereof creates different long-term incentives for market parties to adapt their behavior. Market splitting and market coupling would provide the largest incentives, with distributive effects that are an order of a magnitude larger than the net societal cost of congestion. These methods lead to economically efficient outcomes from a transmission system efficiency perspective, because they impose an

34 Approximately 26 GW. This is the estimated peak load in the Netherlands, minus (assumed) imports from UK and Norway, plus (assumed) exports to Germany and Belgium.

35 Note that the figure of 12,000 MW applies for the Netherlands as a whole. For the separate upstream and downstream areas these values are 2,348 MW and 9,215 MW, respectively.

additional cost for generators located in areas with excess production capacity by making the value of electricity transmission explicit. This provides an incentive for market parties to alleviate congestion, as it discourages new investments in generation capacity and attracts consumers with energy-intensive facilities (note that consumers were not considered by this study).

Although the APX-based method also allocates congestion costs to generators in the upstream areas with excess capacity, the resulting incentive is much smaller. Under this method only the cost of redispatching production capacity to the area downstream of congestion are transferred to generators, whereas under the market splitting and market coupling methods these costs are based upon the economic value of the transmission line. Given the small cost of redispatch, the incentive is much larger under market splitting and market coupling.

Basic system redispatch does not provide an incentive for alleviating congestion, and even enables generators to benefit from inefficient decisions, such as delaying the decommissioning of inefficient units (Hakvoort et al., 2009). This is intrinsic to the method, as it is developed to transfer all responsibility and incentives to the TSO in order to maintain a copper plate approach for the electricity system. Considering the specific characteristics of the Dutch electricity system, however, this is unlikely to play a role in the foreseeable future. All units in the Maasvlakte area (which was found to be most sensitive for congestion) that produce at variable cost levels near MCP (and are thus more likely to be *constrained off* under congestion) are rather new (commissioned between 2003 and 2014). As a result, decommissioning considerations currently play no role.

Strategic bidding

However small the expected cost of congestion may be under perfect competition, strategic bidding analysis has shown that ample opportunities exist for generators to abuse the system in order to create additional revenues. All congestion management methods allowed for generator revenues to be increased by strategic bidding, but as theory (Hakvoort et al., 2009; Hers et al., 2009b) states, basic system redispatch appears to be particularly vulnerable with respect to creating costs for TenneT. Section 6.3.5 has shown that the information asymmetry between TenneT and the generators creates a principal agent problem, with an advantageous bargaining position for generators (the agents). The functioning of the *constrained off* and *constrained on* markets was argued to constitute an Adverse Selection Game as described by Cunningham (2008), under the circumstance that generators know that TenneT (the principal) eventually has no option but to agree to a contract, because otherwise it will not be able to alleviate congestion.

Market coupling and market splitting would decrease the congestion rents TenneT obtains from trade between price zones, if strategic bidding by generators leads to increased prices in the Maasvlakte region. This levels the prices throughout the congestion regions, as a result of which TenneT no longer benefits from inter-zonal congestion rents. However, strategic bidding can only drive down congestion rents to zero, but not create a cost for TenneT. Strategic bidding to artificially increase MCP in the Maasvlakte region would thus negatively affect consumers within that region, as they must bear the costs that arise in the form of higher electricity costs.

Although the APX-based method has the potential to affect TenneT under strategic bidding, it is not expected to create a cost for TenneT under the current characteristics of the Dutch electricity market. This is because TenneT will be able to transfer all arising costs to generators in the upstream area, even in case the congested volume would double compared to the scenario under which the largest extent of congestion was found under competitive bidding[36]. The reason that TenneT will remain financially unaffected is related to the margins available to decrease the MCP received by generators in the upstream area, which are sufficiently large to transfer this cost[37]. This

36 Scenario 1, *Low wind availability in Germany*.

37 The APX-based method transfers congestion costs to generators in the upstream area by creating a difference between the MCP and the MCP that is received by the upstream generators. However, this MCP received will at all times remain at least equal to the cost level of the highest offer that is still accepted after constraining off the volume required to alleviate congestion. See section 4.4.3 for more information.

finding was obtained by analyzing the situation in which a large generator, with capacity both upstream and downstream, bids strategically in the downstream area (expecting to become *constrained on*) while simultaneously attempting to increase the height of the highest accepted offer in the upstream area (i.e. Maasvlakte), in order to prevent the MCP received in this area to decrease.

This strategy was found to be unsuccessful for a generator whose units in the Maasvlakte region produce at a variable cost below marginal levels. In order to increase the highest accepted upstream offer, the strategy would require this generator to offer electricity at a higher price than the current marginal generator (otherwise it will not be marginal and, hence, not influence the marginal price level). However, because the volume offered at the current marginal level is not yet completely called on (under the conditions that were simulated), i.e. there is still capacity available at this cost, the generator attempting to influence the marginal price level would lose a part of its accepted volume. There is a high risk that the lost revenues from this this volume loss would outweigh the additional revenues from artificially increasing the marginal accepted offer (upstream), which as a result would negate strategic bidding revenues and render the strategy non-profitable. This situation is explained in detail in Appendix I.2.5.[38]

38 In particular, observe Table 74 which shows how a generator will lose volume in its attempt to set the marginal offer in the upstream area.

PART III: Design consequences for congestion management in the Netherlands

7 Insights regarding method application in the Netherlands

Quantitative simulation has shown that each of the congestion management methods evaluated in this study performs according to theory with respect to the distribution of congestion costs, when simulated under the assumption of perfect competition. Also, congestion costs were found to be very low even when significant amounts of capacity would need to be redispatched, because of the flat nature of the supply curve around the demand-supply intersection. Strategic bidding analysis has shown, however, that generators in the Netherlands can increase their revenues under every congestion management method by offering capacity at price levels that do not reflect true costs. Depending on the congestion management method applied, different stakeholders would be affected by such strategies.

The objective of this section is to discuss the consequences that the application of each of the methods will have for the specific situation of the Netherlands, with the intention to identify the main advantages and disadvantages of them *for the Netherlands specifically*. It will do so by combining theoretic knowledge and the quantitative insight provided by the simulation model, while taking into account the views of the main stakeholders (TenneT, the Ministry of Economic Affairs, Agriculture, and Innovation, generators, and consumers) all of which have their specific reasons to either or not support particular methods. At the end, this section will discuss whether the application of a market based congestion management method can indeed be expected to lead to higher social welfare in the longer term, as this was discussed to be the reason for the current trend towards such methods in Europe in section 2.1. The findings from this section serve as the basis for performing multi-criteria decision analysis, which is subsequently discussed in Chapter 8.

7.1 Basic system redispatch

One of the main reasons for the Ministry of Economic Affairs, Agriculture, and Innovation to apply basic system redispatch is that it allows users to regard the electricity system as a "copper plate", which they can use to freely trade electricity without being involved in or affected by any transportation issues (Leuthold et al., 2008). As was discussed in section 1.4, this approach is regarded to lie at the basis of a competitive and liquid electricity market (Brunekreeft et al., 2005; NMa, 2009). The responsibility to ensure the adequate functioning of the network resides entirely with the TSO, which in principle has no means to steer market players in their use of the grid. To alleviate congestion, power line capacities can be expanded by TenneT, but this is only a long-term solution (Knops et al., 2001). In the short-term TenneT basically relies on the "willingness" of market parties to help provide relief to immediate, short-term congestion. This willingness, of course, comes at a cost.

In the ideal situation, assuming perfect competition, basic system redispatch meets its intended objective in the sense that it creates very little disturbance for the market. It thereby keeps the involvement of market parties as small as possible, i.e. limited to only those generators that are required to solve congestion. The resulting decrease in social welfare (i.e. congestion costs) is directly allocated to one single stakeholder (TenneT) without creating large financial (counter) flows, as is the case with the market-based methods evaluated (see Table 7 on page 50). All generators and consumers can continue to consider the system as a copper plate and use this notion to base their actions upon.

From a transmission system efficiency perspective, however, the method creates wrong incentives that will in the longer term lead to lower social welfare. If no geographical differentiation is applied in case of congestion, generators and loads will have no incentive to locate themselves efficiently from a transmission perspective (Bjørndal & Jörnsten, 2007; Hakvoort et al., 2009; Leuthold et al., 2008). The simulation results have shown, however, that the costs resulting from congestion are expected to be small. The marginal costs of units that would need to be *constrained off* are nearly equal to those that are *constrained on*.

It is important to realize that both generators and society have a variety of considerations when deciding on the most appropriate location for a new generation unit (e.g. availability of cooling water, fuel supply, ease of obtaining construction permits, presence of nearby residential areas). If strong locational incentives were to be provided to generators, in order to improve transmission efficiency, these may be offset by the negative consequences with respect to other criteria. Especially considering that congestion costs are expected to be small in the Netherlands, it is important to take these factors into account when deciding on an appropriate congestion management scheme.

Incentives for TenneT

As the cost of congestion is allocated to the TSO under basic system redispatch, TenneT is provided an incentive to alleviate congestion through capacity investments. Section 6.2.2 discussed the possibility that these lead to economically inefficient capacity expansions, if investment costs can be incorporated in the transmission tariffs, while congestion costs cannot. This could lead to the undesired situation that expensive capacity improvements are realized, to prevent small congestion costs from arising.

Currently, a scheme exists under which TenneT is allowed to incorporate the costs from occasional congestion in its transmission tariffs, but cannot do so with respect to structural congestion costs. For economically optimal results (i.e. the level of socially optimal investments is consistent with the optimal investment level for TenneT) this scheme should rightly balance when congestion costs can, and when they cannot be transferred. For example, under such a scheme TenneT could apply to the Office of Energy Regulation to obtain permission for passing on the costs of congestion to its customers for a period of, say, five years, if it can convincingly argue that the cost of expanding the grid outweigh the cost created by congestion. This approach would lead to a socially optimal outcome because unnecessary investments are avoided, while the limited duration of such permission still provides TenneT with an incentive to take long-term developments into account and invest in transmission capacity if it expects these to be required in the future.

Institutional embedding

Only those generators that are physically required to alleviate congestion are involved in the basic system redispatch scheme. All others can implement their market transactions without 'noticing' that basic system redispatch is being applied. The method thus requires no change in market structure, as it is an additional mechanism that is applied independently from regular market transactions. It is institutionally easy and quick to implement, which was one of the reasons for the Ministry to go with this option in the first place (Hakvoort et al., 2009).

Although the method aims to involve market players as little as possible, it does not come without some kind of burden for the generators that are not physically involved. Basic system redispatch requires generators (with capacities > 60 MW) to submit *constrained off* and *constrained on* offers to the TSO ex-ante, which creates a transaction cost that applies to all generators – not just those that are physically involved (Hakvoort et al., 2009).

Strategic bidding

As was shown in section 6.3, there are opportunities for generators to bid strategically in order to increase their profits at the expense of TenneT. It is difficult, however, to predict whether – and to what extent – these opportunities will be actually deployed. It has been mentioned before that these are limited to artificial fluctuations of roughly 10 or 20 percent according to Hers et al. (2009b), because larger manipulations would be noticed by the competition authority. An additional component to this discussion is introduced by Nooteboom (2000), who discusses that two conflicting perspectives on opportunism exist: social exchange theory and transaction cost economics. He argues that the former approach assumes the behavior of companies to be primarily guided by reciprocity, mutual forbearance and trust, whereas the latter assumes that firms in principle behave opportunistically, and emphasizes the monitoring of performance and (legal) sanctions.

Generators do not operate isolated from other stakeholders in the electricity sector. Rather, they frequently interact with a network of other stakeholders, such as the government and TenneT, but also with society, for instance through their appearance in the media. Although increasing revenues through strategic bidding may seem as an attractive strategy for a generator which has this opportunity, it could backfire in the longer term by deteriorated relations with stakeholders it may depend upon in the future. The importance of maintaining such relations is discussed by De Bruijn & ten Heuvelhof (2008), who discuss that rounds of interaction among stakeholders can usually not be considered in isolation. One who wins a round of interaction, e.g. a generator that successfully increases its profits by 'milking' TenneT under an instance of congestion, will inevitably meet the other stakeholders again when another issue is on the table.

The influence of factors other than sole short-term economical rationality greatly complicate the prediction of what strategic bidding cost could be expected. Even if one were to model the behavior of individual generators separately using an agent-based model –an approach which has been discussed before as to provide a means for improvement of the insight strategic bidding consequences– such a model would need to cover an enormous scope of elements that influence behavior. Moreover, one should realize that simulating such social interaction may even be utterly impossible to perform accurately.

Summarizing the above, accurately predicting the effects of strategic bidding is extremely difficult, primarily because it is not only based on short-term economic rationale, but also on other, “softer” factors. The only way to really determine the consequences of strategic bidding may therefore be to observe reality. The model constructed during this study could provide a means for TenneT and the Office of Energy Regulation to improve their ability to identify when generators bid strategically, because it allows for a comparison to be made between their actual behavior and the behavior they would exhibit under conditions of perfect competition.

7.2 Market splitting

Although having the same effect on net social welfare as basic system redispatch, market splitting creates both large benefits and losses for different market players. The height of the monetary transactions, calculated as the sum of all absolute surplus differences[39], appears to be an order of a magnitude larger than the transactions under basic system redispatch (see the figures provided in Table 7). In the specific situation of the Netherlands, market splitting would create a strong incentive for generators not to construct any additional capacity in the Maasvlakte area. Because the method puts a price on contributing to congestion and, thus, decreases revenues for generators, it rather heavily penalizes all those located in the area despite the fact that the net societal cost of congestion is small. This also discourages new production capacity – both cheap and expensive plants, as both would experience a decrease in the market price – to be located in the area. This is in line with earlier findings by De Vries & Hakvoort (2002), who also found that market splitting has a larger impact on financial flows, despite resulting in the same net welfare difference.

The congestion cost components that are allocated to the different market players under market splitting reflect the value of the scarce transmission capacity, rather than the actual (total) cost of congestion that is created by sub-optimal dispatch of units. Generators 'pay' for the use of this scarce resource in the form of a lower MCP, of which the TSO reaps the benefits because its congestion rents increase. Any generator that is unwilling to 'pay', which it signals through the height of its supply offer, will see its offer be rejected on the market. From a grid efficiency perspective this effect can be considered as an advantage of the method, because it discourages generators to invest in the area that already has excess production capacity in place. However, it also heavily affects existing producers negatively. This is considered unwanted by the Ministry, which seeks to implement a measure that allocates congestion costs proportional to the extent of congestion (Hakvoort et al., 2009).

Institutional embedding

The simulation model used during this study assumed all electricity to be traded on a national spot market which, if necessary, was split under congestion. It is important to realize that such a market

39 i.e. counting a benefit of € 1000 to stakeholder A, and a loss of € 1000 to stakeholder B, as € 2000.

is currently not in place in the Netherlands, which means that the implementation of market splitting would require a large institutional change that forces all electricity trade –possibly with the exception of intra-nodal trade– to take place on an organized spot market. This is currently the case in, for instance, the Nordic electricity market, where market players can only trade electricity either with others located in the same node or on a central power exchange (Kristiansen, 2007b). Hence, bilateral cross-node trade can cannot take place directly and must be organized by the use of financial contracts, while the trade of physical capacity takes place either on the power exchange or with a local counterpart (Glachant & Pignon, 2005).

Incentives for TenneT

TenneT would experience a net benefit under market splitting, because it profits from electricity trade between different price zones. Although this net benefit potentially serves as a discouragement to resolve congestion, it can also be dealt with in a similar manner as European market coupling, under which all TSO benefits are invested in the transmission network (EMCC, 2011). Such constructions were also discussed by Bjørndal & Jörnsten (2007) and Kristiansen (2007b). However, as the societal net cost of congestion appears to be small, this may create a similar situation as described for the basic system redispatch method, in which a societal sub-optimal situation is created because grid expansion costs outweigh the actual cost of congestion. The transfer of wealth to TenneT may therefore lead to socially sub-optimal outcomes, if regulatory provisions force TenneT to “waste” congestion rents by solving a small problem at excessive cost. If market splitting were to be considered for the Netherlands, it is therefore strongly recommended to design an appropriate 'congestion-rent-allocation-scheme', which specifies how congestion rents may, or should, be spent.

Given the current transmission tariff structure, all costs resulting from grid investments are eventually shifted to consumers (Energie^{+}, 2010). Generators only pay a fixed annual connection fee, which results in a situation where the infrastructure required for allowing a *generator* to export, is incorporated in *consumer* tariffs. The application of market splitting in the Netherlands would lead to a wealth transfer from generators in the Maasvlakte area (which has excess capacity and requires grid infrastructure to transport power to other areas) to TenneT (as well as consumers). This would create a more balanced pricing structure for electricity transmission, with a shift from consumer-only to *both* consumers and generators. In the event that the Netherlands becomes a net exporter of electricity, as is currently expected, this prevents domestic consumers from having to bear grid costs while all gains from international trade are allocated to generators. This falls under the general issue of transmission pricing, however, and constitutes a political decision.

7.3 Market coupling

Market coupling was found to yield the same economic results as market splitting. Although it takes a different approach with respect to defining congestion zones, it eventually seeks to maximize the use of transmission capacity in order to create single price zones that are as large as possible. This is also done under market splitting, except that market splitting assumes a single price zone to begin with and separates this area into smaller zones if necessary.

With respect to non-economic criteria there are some differences between the methods. First of all, this study assumes that the four Dutch nodes will be cleared on a European level under market coupling. This relieves TenneT from being required to compensate interconnected TSOs in case congestion rents are different from the Netherlands as a single price area. This can be done because when clearing the Dutch market (better: four Dutch markets) under the European market coupling mechanism, congestion can no longer occur within the Netherlands: transmission capacity is by definition auctioned to its fullest extent, without exceeding capacity constraints. As a result, there can no longer be any scheduled flows that exceed the available capacities.

Similar to market splitting, market coupling also imposes large institutional changes by creating the need for a mandatory spot market (at least for inter-nodal trade); please refer to the discussion on this in section 7.2.

7.4 APX-based method

The APX-based method is somewhat similar to *system redispatch with cost pass-through to generators* (see Appendix B.1.3). The responsibility to redispatch capacity resides with TenneT, which needs to *constrain off* capacity and acquire the compensatory *constrained on* power. Congestion costs are allocated to generators in the *constrained off* zone which are not *constrained off*, albeit within limits determined by the height of the highest accepted marginal offer. The main difference with *system redispatch with cost pass-through to generators* is that the APX-based method takes an implicit approach to the redispatch markets, without making use of an additional market process for separate *constrained off* and *constrained on* bids.

On the basis of the scenarios that were simulated, the APX-based method creates (small) costs for generator that are not *constrained off* in the upstream area. Although the method would also allocate some costs to TenneT if these become sufficiently large, simulation has shown that this is unlikely to happen in reality because, under the conditions of the *Low wind availability in Germany* scenario, the congested volume could grow more than twice as large before TenneT would be unable to recover all of its redispatch costs[40].

Institutional embedding

The APX-based method was developed by TenneT with the aim to address the Ministry's requirement that the application of congestion management should not create different price zones in the Netherlands. It makes use of a mandatory spot market to determine which units need to be redispatched in case of congestion, which creates additional transaction costs for those generators that would otherwise trade their electricity outside this market[41]: they now need to both place offers (and possibly bids, in case other supply obligations exist) at the spot market, as well as arrange their trade with parties outside the spot market. However, bilateral trade is still possible as the spot market bids and offers only serve the purpose of determining transmission flows and the allocation of congestion costs.

7.5 Applying methods in the Netherlands: conclusions

Under the assumption of perfect competition, all evaluated methods resulted in very low congestion costs. Although the schemes have different distributive effects, the net effect of congestion for society is almost negligible. These distributive effects, however, have important implications for the incentives that result from the application of congestion management methods. The distribution of wealth may potentially create (strong) incentives for parties to take action, even though on a system-wide level society may be better off by simply accepting (some) congestion and the resulting cost.

The current chapter described how the small hourly congestion cost of € 231 could lead to expensive transmission capacity expansions under system redispatch, even though this capacity would only be used to allow units to be dispatched that produce electricity at a cost that is in the order of magnitude of 0.1% lower. To illustrate this: even if the same amount of congestion would occur during every single hour of the year, investments that cost hundreds of millions of euros would be made in order to achieve dispatch efficiency gains that save society € 2 mln. a year.

Under the market-based methods congestion costs could also lead to socially undesirable actions. Although market splitting and market coupling attach a price to scarce transmission capacity, the congestion-relieving actions that are taken on the basis of these costs – which are efficient from a transmission perspective – may cause other, socially undesirable effects. For instance, locating a lot of production capacity at the Maasvlakte is inefficient from a transmission perspective, but locating coal-fired power plants at that location may be[42] socially desirable from

40 This calculation is provided in Appendix I.2.5, on page 174.

41 Note that despite the existence of a mandatory spot market it is still possible to trade electricity outside this spot market, as is discussed in Appendix B.2.2.

42 The advantages of geographical siting were not a part of this study, and therefore the phrase 'may be' is preferred above 'is'.

e.g. an environmental (far away from residential areas) or a security of supply (fuel and cooling water availability) perspective. These could also be expressed in monetary form, and the provision of a strong incentive to reduce congestion that is solely based on transmission system efficiency, may thus not be in the societal interest.

As a general conclusion to the evaluation of congestion management methods applied in the Netherlands, the above can be summarized by stating that the quantitative evaluation of methods has found that not a single, "almighty" congestion management method can be distinguished on the basis of their economic welfare effects. Nonetheless, it has provided other useful insights, such as that with the current availability of production units (i.e. available in 2016) congestion costs are expected to be small. Also, several aspects with respect to the secondary and long-term effects of applying these methods in the Netherlands were explained. To conclude this chapter, the next paragraph will discuss the proposition that market-based congestion management methods produce more efficient (and thus better) outcomes than basic system redispatch.

Efficiency of market-based methods

The proposition that market-based methods lead to more efficient outcomes than non-market-based methods, which was introduced in section 2.1, was found to apply, but only in the long-term and when considering the issue from a mere transmission system efficiency perspective. Quantitative simulation showed that all methods perform equally well with respect to short-term efficiency and that they only differ in their distributive effects. These results were found to be consistent with existing literature. The congestion cost allocation of market splitting, market coupling, and –albeit to a lesser extent– the APX-based method provides better incentives for generators to behave efficiently, considering the availability of transmission capacity, than basic system redispatch.

However, this chapter also discussed that there are more relevant factors than transmission system efficiency only. Generators have various reasons to decide on a particular location for a new production unit, and a transmission-inefficient decision may very well outweigh the costs of congestion. This is particularly true when considering the fact that congestion costs are expected to be small in the Netherlands. The market-based methods that create incentives to discourage generation capacity from being located in areas with excess capacity were found to create strong incentives for generators to locate outside these areas. However, such strong incentives could force generators to take decisions that are efficient from a transmission system efficiency perspective, while these may be outweighed by the negative consequences on other criteria (which can be either or both in the societal interest and/or the interest of the generator).

Although transmission system efficiency is indeed an important criterion for determining which congestion management method is most appropriate for application in the Netherlands, it will only be one out of several criteria that were considered when performing multi-criteria decision analysis, the results of which are presented in Chapter 8.

8 Design criteria for congestion management in the Netherlands

As was discussed in the previous chapter, the choice of congestion management method will have consequences that reach further than merely determine the allocation of congestion costs. The objective of this chapter is to clearly specify what the application of congestion management should and should not lead to (section 8.1), and subsequently evaluate how the different congestion management methods adhere to, or preclude, meeting these goals (section 8.2). Because there are issues – as these sections will show – that could not be (fully) addressed by this study, some knowledge gaps and design variables that depend on socio-political desires, remain open. An overview of these is provided in section 8.3, including a brief discussion for each on how they can be answered (pure knowledge gaps) or which stakeholder should take action (policy options).

8.1 Objectives of applying congestion management

Until the liberalization of the electricity market in 1998, congestion management was hardly an issue in the Netherlands. Both the authority for construction (and decommissioning) of production units, as well as the responsibility for maintaining an adequate transmission infrastructure, resided with a single organization (SEP; see section 1.1). This guaranteed their consistent development and precluded the need for congestion management, as congestion was prevented from arising in the first place. Also during the first decade after liberalization congestion on the transmission grid was no issue, because no (large) new production units were constructed in the Netherlands. The situation changed over the past few years when multiple generators announced their plans for the construction of new production units (Persson, 2009), in combination with the regulatory change that now requires TenneT to connect all new entrants to the grid immediately, even when insufficient transmission capacity is available. This creates the possibility that congestion will arise, because production unit and transmission system development are no longer consistent by definition.

Given the developments described above it is unavoidable that congestion management must be applied. Because the methods possess different characteristics, as a result of which their application may lead to different outcomes, it is important to assess to what extent the methods contribute to achieving the policy objectives set by the Ministry of Economic Affairs, Agriculture, and Innovation. These objectives, on the basis of which multi-criteria decision analysis was performed using the ARGUS[43] method, are discussed in the next sub-sections, and follow from the (relevant) criteria used by Hakvoort et al. (2009), Knops et al. (2001), and findings from the preceding chapters of this study. A summarized overview of the policy objectives is provided at the end of this section, in 8.1.11.

8.1.1 Facilitating locational excess production

Knops et al. (2001) distinguish two types of congestion: physical congestion and economic congestion. 'Physical congestion' is used to refer to a situation where demand cannot be met everywhere in an electricity system as a result of transmission limits, whereas 'economic congestion' refers to a situation in which one or more grid elements become congested, while this can be solved by altering the dispatch pattern (i.e. by redispatching). Although the definition of congestion used during this study (the transmission flows resulting from the transaction pattern as desired by the market cannot be physically implemented due to transmission constraints – see section 1.2.1) captures both types of congestion, this study has focused on congestion as under the definition of 'economic congestion' of Knops et al. (2001). The nodal approach that was used during the

	Nodes		Peak load	ATC (max)
1	North Netherlands	NN	3098	5556
2	Ring	RN	15363	10875
3	Maasvlakte	MV	1290	4205
4	Zeeland	ZL	1287	5735

Table 12: Transmission capacity versus peak loads

43 **A**chieving **R**espect for **G**rades **U**sing ordinal **S**cales only (Pruyt, 2009, p. 140).

modeling study contributed to this, because it assumes a highly meshed internal grid within each of the nodes, which precludes that transmission capacity would at any time be insufficient to physically meet demand in an area or for a particular customer. Also, it is unlikely that demand of a node as a whole cannot be served, given that the available transmission capacities between the nodes are in the order of magnitude of their peak loads (see Table 12).

Congestion in the Netherlands will thus be primarily of an economic nature, i.e. the economically optimal dispatch pattern cannot be implemented physically. As large amounts of capacity are planned for regions that do not require the additional supply of power itself (Maasvlakte, Eemshaven), this power needs to be transported to regions where it will be used. Congestion management must thus be applied in the Netherlands to cope with excess production capacity in regions that are geographically advantageous[44] for locating production units. The underlying reason for creating a situation with these excess production capacities originates partly from the socio-political desire that electricity producers should neither be involved, nor affected by network planning affairs. This has, for instance, led to the new connection policy that has been discussed extensively throughout this report (see e.g. section 1.1).

From a transmission system efficiency perspective this is expected to lead to sub-optimal siting of production units, because all costs that result from a locational decision of an individual producer are socialized, and thus not form a consideration for this producer when planning their new unit (Hakvoort et al., 2009; Hers et al., 2009b; Leuthold et al., 2008). To allow the market to function optimally, the transmission efficiency criterion was considered better not to exist for generators. This forms the essence of the copper plate approach: the societal benefits from improved market functioning are considered to be larger than societal costs resulting from (potential) transmission system inefficiency. The next paragraph will argue how this can also lead to excessive costs, which outweigh the social benefit of improved competition and therefore pose an undesired outcome of the approach.

Ideal transmission pricing scheme

To assess whether the non-involvement approach yields a benefit to society, one must determine whether societal benefits indeed outweigh societal costs. What one basically wants to achieve from the copper plate approach is that if transmission costs from a particular siting decision are larger than a generator's revenues, but smaller than societal benefits from improved market functioning, these costs are not allocated to the generator because it would not make this (socially efficient) decision. However, the approach in its current form also allocates transmission costs to society if the locational decision is inefficient from a societal perspective. This forms a perverse incentive under which a generator could choose for a very expensive location if it yields higher revenues, because all costs are allocated to society anyway. Society would then, basically, be subsidizing generators by enabling them to increase profits even when the costs (which are borne by society) outweigh the revenues.

Ideally, a scheme would exist under which transmission costs are partly socialized and partly allocated to generators, to the extent that they are indifferent about locations that are socially equally efficient. Under the copper plate approach these locations may yield a different profit level, because only the difference in profits excluding transmission costs matters, and this difference in transmission costs itself does not. This would prevent excessive transmission costs from being transferred to society, but still leave the main objectives of the copper plate approach –creating a level playing field for generators with respect to electricity transmission– intact. In its optimal form, however, such a scheme would require TenneT to be able to precisely quantify the benefits that a generator obtains by choosing an inefficient location from a transmission perspective. This is utterly impossible, because even if a value can be attached to the financial components of such decisions, other considerations – such as the ease of obtaining permits, and the availability of labor and fuel – may not be objectively expressed in monetary terms.

44 Advantageous: if transmission system efficiency needs not be considered.

8.1.2 Cost efficiency

Application of congestion management creates costs to one or more stakeholders because of two reasons. First, a societal cost (regardless of its allocation) is created because it inevitably implies a deviation from the optimal dispatch pattern. Second, the congestion management methods all allocate congestion costs in a different manner. Some (e.g. basic system redispatch) only allocate the loss of social surplus to one stakeholder, whereas others (e.g. market splitting) create both (relatively large, compared to the loss in total social welfare) benefits as well as large costs that are allocated to different stakeholders. These allocation schemes all create different incentives for investment in production capacity, energy-intensive industries, and transmission infrastructure, all of which can contribute to alleviating congestion in the long-term – or, alternatively, enlarge the problem.

As was discussed in section 1.3 congestion management is currently regarded by the Ministry of Economic Affairs, Agriculture, and Innovation as a temporary measure to alleviate congestion that occurs because the required transmission system reinforcements are not yet implemented. Section 1.4, however, discussed that TenneT in some cases expects congestion to be of a more structural nature, which requires that the method used to manage congestion is applied (semi-)permanently. In a letter to Parliament the Minister of Economic Affairs stated that “scaling to a new system for congestion management” would be an option in the case of “congestion of a more structural nature or those of a large extent” (Minister of Economic Affairs, 2009, p.7, translated quotes). This “new system”, which should be based upon an implicit auctioning mechanism, should also provide correct signals to market players. There thus appears to be an inconsistency in the reasoning of the Ministry.

The direct need for congestion management currently arises from the need to facilitate excess production capacity in particular regions of the Netherlands, until the required transmission reinforcements are complete. This was discussed in section 8.1.1. The objective of providing the right incentives conflicts with this objective, because these incentives (i.e. allocated congestion costs) are meant to prevent excess capacity from being constructed. However, the current generators that were responsible for creating excess capacity in the low-demand Maasvlakte region were never made subject to this incentive. If it were to be implemented, it would only provide an incentive not to construct any new capacity while not alleviating the congestion created by existing units. The inconsistent approaches regarding congestion management method objectives were therefore interpreted as follows: congestion management should facilitate existing production in areas with excess capacity, but it should discourage new units from being constructed there.

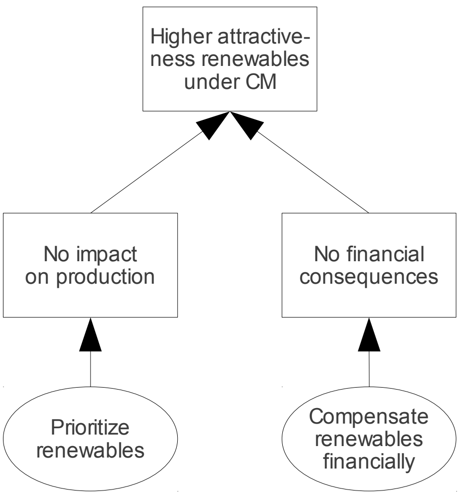


Figure 8: Prioritizing renewables: brief goal-means analysis

8.1.3 Proportionality

The Ministry has a preference for congestion management methods that solve congestion in a proportional manner, i.e. “the 'impact' of the congestion management system should match the seriousness of the congestion” (Hakvoort et al., 2009, p.26).

8.1.4 Priority for renewables

One of the environmental objectives that the Ministry wants to achieve when congestion management applied, is that it contributes to –or at least does not preclude– the (economic) feasibility of renewable energy in the Netherlands. Currently, this primarily entails wind power, especially when considering the planned capacities for offshore wind farms (see Appendix D). The difference between renewable power sources and conventional power plants is that renewable, and often intermittent sources create fluctuations on the transmission grid that are entirely subject to external influences (e.g. the availability of wind). Unlike conventional power plants, it is not possible to precisely plan ahead how much electricity will be generated at a particular moment, and redispatching the production of a wind farm to another whenever desired, is completely out of the question.

In order to promote these energy sources the Ministry requires the application of congestion management to allow all electricity produced from renewable sources to be prioritized in case of congestion. A brief (and very simple) goal-means analysis, shown in Figure 8, teaches that prioritization of renewable energy sources under congestion is actually not the main goal itself. Rather, the Ministry aims to improve, or at least maintain the attractiveness to invest in renewable energy sources at the same level, without these generators having to worry about the potential consequences of congestion. Figure 8 shows that this goal can also be met by guaranteeing that renewable energy sources are not financially affected by the application of congestion management, for instance by compensating the costs that result from being *constrained off*.

Intermittent energy sources and the purpose of congestion

With the increase in intermittent power sources, supply patterns can be expected to show additional fluctuation. Most of the time it is therefore not necessary for transmission capacity to be equal to the sum of all rated capacities, because these sources will only rarely produce at their maximum production rates at the same time. It may therefore be more efficient to *accept* occasional congestion in the transmission grid, rather than to invest in expensive infrastructure that is only used to its full extent in the rare instances that all intermittent sources generate at their maximum production rate. Congestion management can thus serve a purpose as a structural alternative to transmission capacity expansions, because the cost of redispatching once in a while (regardless of the congestion management method) may be economically more efficient than having large transmission capacities in place to enable TenneT to cope with all possible intermittent generation patterns.

8.1.5 Limited vulnerability to gaming

Manipulation of the congestion management scheme by bidding strategically is clearly unwanted and implementing a method that limits the possibilities for this is explicitly favored by the Ministry (Minister of Economic Affairs, 2009).

8.1.6 Compliance with institutional and legal framework

The unbundling of the competitive activities from the non-competitive activities in the electricity supply chain is laid down on both a European (Directive 2009/72/EC) as well as a Dutch level (Electricity Law 1998; Dutch: Elektriciteitswet 1998). Electricity transmission (and distribution), which constitutes a natural monopoly, is separated from the competitive elements of generation, retail, and metering, in order to create a level playing field and facilitate fair competition with respect to these competitive elements. This section briefly discusses the consequences that these institutional principles (may) have for the application of congestion management.

According to Knops et al. (2001), the application of a 'corrective' congestion management method, under which the TSO alleviates congestion “behind the scenes” (Knops et al., 2001, p.338) and which requires the TSO to actively trade on the electricity market, may violate the unbundling principles of electricity transmission and trade. Basic system redispatch and the APX-based methods are both corrective measures, but the following paragraph will argue that the criticism of Knops et al. (2001) does not apply because of inherent differences with the corrective measures described by them.

The application of basic system redispatch, which is the current approach to deal with congestion in the Netherlands, requires TenneT to act on the *constrained off* and *constrained on* markets in order to acquire sufficient volumes in order to alleviate congestion whenever necessary. Because these markets constitute an additional market mechanism that does not interfere with regular trading, it does not conflict with these unbundling principles. Under the APX-based method, TenneT would be required to trade on the regular electricity market. However, as it will merely act on the basis of a fixed set of rules, which consist of acquiring the volume required to alleviate congestion by accepting the cheapest offers first, and as this trade takes place transparently on a spot market (i.e. there will be no bilateral contract negotiations of any kind), this process could be carried out by an independent market operator. TenneT would in this situation only submit the volume that is required to be redispatched, but would not need to be actively involved in the trading process.

Market splitting and market coupling could make use of a similar construction (Knops et al., 2001). The trading procedures take place transparently according to a fixed set of rules and no active trade is required to be done by TenneT, thus safeguarding the legal unbundling principles.

8.1.7 Non-discrimination

The main reason for the Ministry's new connection policy was to remove the existing discrimination between existing and new users (Hakvoort et al., 2009). All of the assessed methods adhere to this principle.

8.1.8 Simplicity and transparency

All methods assessed make use of clear and transparent predetermined trading principles when alleviating congestion. (Hakvoort et al., 2009)

8.1.9 Influence without congestion

Knops et al. (2001) argue that any congestion management method should “not impose upon the market if there is no congestion” (p. 318). With the exception of market coupling, all evaluated methods allow for implementation of the market transaction pattern assuming no transmission constraints as long as no congestion arises. Market coupling reverses this approach, by dividing the market at first and subsequently seeking to “undo” the effects of this division, but as it leads to the same outcome as the other methods (equal unit dispatch and congestion cost allocation) when there is no congestion, it can also be considered to adhere to this principle.

8.1.10 Excluded criteria

Some of the criteria used by Hakvoort et al. (2009) and Knops et al. (2001) to assess congestion management methods were excluded in this study, because they were found not to apply. The reasons for excluding these criteria are briefly discussed below.

Technical criteria (Hakvoort et al., 2009)

Part of the scope of Hakvoort et al. (2009) were four technical criteria: applicability (the methods must be able to manage congestion arising anywhere in the Netherlands), effectivity (it must alleviate all congestion, rather than only to some extent), network safety, and incentives for information supply.

- The applicability and effectivity criteria do not apply because the definition of nodes was such that congestion could be alleviated everywhere and to its full extent anywhere in the country.
- All methods that jeopardize network safety explicitly fell outside the scope of this study (section 2.5).
- Deliberately supplying the wrong information on plant dispatch (and thereby network usage) can be used by market players to artificially create congestion and benefit from the application of the basic system redispatch method. Incentives for information supply are therefore assessed as a part of the *Vulnerability to gaming* criterion.
- *Incentives for information supply is not excluded.*

Accuracy of cost assessments (Hakvoort et al., 2009)

Hakvoort et al. (2009) provided a theoretical analysis of congestion management methods which did not calculate the congestion costs that would result from specific application of the methods in the Dutch electricity system. This study has quantitatively evaluated the methods on the basis of the congestion costs that result from the application of different methods using a model that incorporated the specific characteristics of the Dutch electricity system (location of generation units, ownership of generation units, market processes, transmission system, etc.) which allowed for congestion costs to be calculated on the basis of true system characteristics.

Speed of implementation

Because the Ministry needed to implement a congestion management method on a short time-scale in order to facilitate its new connection policy, Hakvoort et al. (2009) were required to limit their analysis to short-term implementable methods. This study focuses on the longer term as well, and is therefore not limited by this criterion.

8.1.11 Criteria for the application of congestion management in the Netherlands

The preceding sub-sections discussed the various objectives of and elements that influence congestion management policy in the Netherlands. To conclude this section, these are listed in the overview below. An appropriate congestion management method must:

- Achieve short-term efficiency (least-cost dispatch under congestion constraints)
- Maintain (or improve) the level of attractiveness for renewable energy investments
- Be proportional to the seriousness of congestion
- Facilitate existing production in areas with excess capacity
- Discourage new units from being constructed in areas with excess capacity
- Have a limited vulnerability to strategic bidding
- Signal an efficient level of transmission investments
- Comply with institutional and legal framework
- Be non-discriminatory regarding existing and new network users
- Be simple and transparent procedures and effects
- Have no influence when there is no congestion

8.2 Qualitative assessment of congestion management methods

This section assesses the four congestion management methods on the basis of the criteria that were identified in section 8.1.11. Section 8.2.1 will discuss the multi-criteria decision analysis (MCDA) method that was applied (ARGUS) and elaborate on the suitability of this method for the decision-making problem at hand. Subsequently, section 8.2.2 will score the methods on the basis of these criteria. Because not all criteria are equally important, this must be taken into account during MCDA. Section 8.2.3 discusses the differences in the importance of the aforementioned criteria. Section 8.2.4, finally, presents the outcomes of performing multi-criteria decision analysis using ARGUS. This will provide an insight in the performance of these methods by comparing the methods to each other using pairwise comparisons.

8.2.1 MCDA method

The criteria listed in section 8.1.11 differ from each other in terms of both importance and the effect they have on discerning the methods. Because it is not possible to quantitatively determine the importance criteria, at least not with the information presently available, and because it is not possible to trade-off scores on different criteria (again: at least not with the information presently available), the importance of the methods must be defined by establishing a qualitative order between them.

Given that the scores on the different criteria are primarily qualitative as well, an *outranking MCDA-method* must be applied in order to establish a preference order among the available methods (Pruyt, 2009). The ARGUS method (see Pruyt, 2009) was found most appropriate for this MCDA problem, because all scores are ordinal[45], and this also applies to the weights that should be attached to the criteria to accurately reflect the importance order that exists.

Understanding ARGUS: Dealing with Olympic performance comparisons

After every Olympic Summer Games and Winter Games a medal table is made up to compare a nation's performance at the event. This table presents a per-country overview of all gold, silver, and bronze medals that were won during the Games, and ranks the medal-winning countries accordingly. The position of most of these table entries appear rather straightforward. For instance, during the 2010 Vancouver Winter Olympics, one could say that Canada (ranked 1st by the International Olympic Committee with 14 gold, 7 silver, and 5 bronze medals) clearly outperformed South Korea (ranked 5th, with 6 gold, 6 silver, and 2 bronze medals).

When ranking countries according to their Olympic performance, the International Olympic Committee (IOC) ranks the nations according to the number of gold medals first, and takes silver medals into account only in case of a tie. If two countries have an equal number of gold and silver medals, the bronzes make the difference. This approach implicitly assumes that a gold medal is worth more than any number of silver (or bronze) medals. However, would it still make sense to conclude that Country A, with 1 gold and no silver/bronze medals, has outperformed Country B, with 0 gold medals, but with 62 silver and 38 bronzes?

Similar, albeit usually less extreme, situations often occur during the Olympics, for instance at the same event mentioned above, when comparing Canada to the United States (ranked 3rd, with 9 gold, 15 silver, and 13 bronze medals). Although Canada has won five more gold medals, the US has eleven more medals in total. If the 'value' of each of the types of medals could be determined quantitatively and objectively, a fairly simple calculation could be used to determine the total performance. Unfortunately, the only (fairly objective) information we have, is that a gold medal represents a better achievement than a silver, and a silver represents a better achievement than a bronze. It is thus impossible to objectively declare which country performed better, because this inevitably requires one to determine how many silver medals it takes to 'compensate' for a gold medal performance.

Without consensus on the valuation of the methods, one can only accurately conclude that Canada and the US both outperformed South Korea, but no conclusion can be drawn with respect to the performances of Canada and the US compared to each other. Note that being unable to conclude which of the countries performed better does ***not*** *imply that they performed equally well: there is simply insufficient information available to conclude anything with respect to the performance difference between this pair of countries. The above is illustrated by Figure 9, which shows the outranking relations for the top six performers according to the official IOC rankings. Observe that without an explicit “medal value framework”, which specifies how different achievements (medals) should be compared, insufficient information is available to conclude which of the top-three countries (Canada, Germany, USA) actually performed best at the Games. Particularly observe that Canada (ranked 1st) cannot be said to have outperformed*

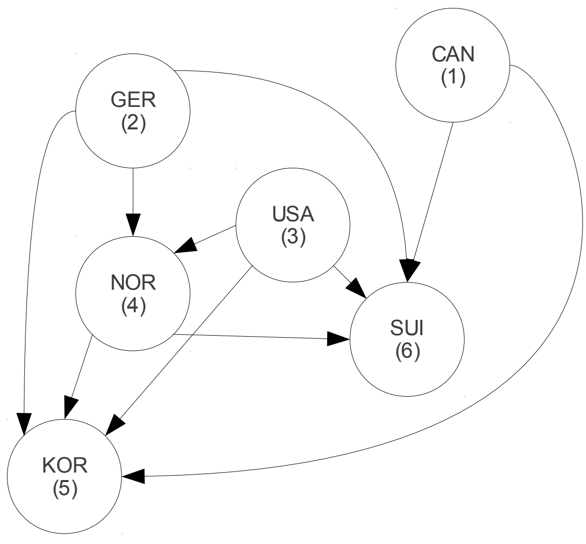


Figure 9: Outranking relations for Vancouver Winter Olympics 2010 performances

45 With the exception of short-term efficiency, as is discussed in section 8.2.2. However, because all methods score equally on this criterion, it was removed from the analysis as it does not contribute to establishing a preference order.

Norway (ranked 4th with 9 gold, 8 silver, and 6 bronze medals), whereas Germany (ranked 2nd) and the US (ranked 3rd), on the other hand, did outperform Norway – even though they rank lower than Canada on the basis of the official IOC rankings. Germany and the US have more gold, more silver, and more bronze medals each than Norway, whereas Canada only outperforms Norway in terms of gold medals, but has less silver and less bronze medals. It can therefore not be said to have outperformed Norway by objective standards.

To make the matter even more complex, one should realize that the example above implicitly assumes that all gold medals represent an equal achievement, i.e. a gold medal in skiing is 'worth' the same as a gold medal in hockey, and so on. This study is not meant to debate whether this is desirable for Olympic comparisons. However, as other decision making problems may require the application of this notion in order to accurately reflect the information and preferences that are considered, it is nevertheless relevant to point out that ARGUS is capable of dealing with such performance valuations.

Many complex decision-making problems require the decision maker to decide on a strategy from a set of strategies, based upon criteria of which the importance cannot be expressed quantitatively (using numerical weights). The ARGUS method was developed to facilitate decision-making under such circumstances, by providing a method that enables one to create some kind of order in a set of strategies that cannot be objectively ranked from best to worst on the basis of quantitative (or quantifiable) scores and criterion weights.

The information and examples provided in this box are not meant to provide an exhaustive explanation of the ARGUS method. Rather, it aims to provide the readers of this report that are not familiar with the wide variety of MCDA methods available, with a feel for the characteristics of the decision-making complexity that is currently dealt with. Also, it aims to specify why a straightforward ranking of alternatives is not always possible or accurate and has shown which type of conclusion will eventually be drawn by this study on the basis of the problem characteristics and consequent application of the ARGUS method. For a detailed description of ARGUS and an elaboration on its position within the overall set of MCDA methods, please refer to Pruyt (2009).

Simply stated, ARGUS can be explained as to award medals to methods for their performance on different criteria. These medals are awarded on the basis of known information and data on method performance regarding a particular criterion, taking into account the degree of importance that is attached to that criterion. By performing this analysis in a pairwise manner, a similar table as shown in Figure 9 can be obtained which indicates how the congestion management methods score relative to each other. Using this insight one can determine which methods outperforms others, and whether there is a method that can be concluded to be more appropriate than any other method.

8.2.2 Congestion management method scores

Table 13 presents an overview of the qualitative and quantitative scores of the congestion management methods on the aforementioned criteria. The scores and their determination will be discussed below. Note that most criteria are scored on an ordinal scale, i.e. their score in Table 13 should be interpreted as only providing information on the *order* of method performance, rather than on their actual performance.

Furthermore, it is important to point out that the methods **cannot** be compared on the basis of a comparison of total scores, which one could calculate by assigning a numeric value to each of the signs. For the actual comparison of methods, please refer to section 8.2.4 which presents the results that were obtained by applying the ARGUS outranking method.

Criteria	BSR	MS	MC	APX
Short-term efficiency	++	++	++	++
Attractiveness of renewables	++	=	-	++
Proportionality	+	-	-	+
Facilitate existing production	+	--	--	-
Discourage new excess capacity	--	++	++	=
Vulnerability strategic bidding	--	+	+	=
Efficient transmission signals	++	-	-	=
Compliance institutional f.'work	++	=	=	+
Non-discrimination	+	+	+	+
Simplicity and transparency	+	+	+	+
Influence without congestion	=	=	=	=

(++ very good) (+ good) (= neutral) (- bad) (-- very bad)

Table 13: Qualitative scores of congestion management methods

For more information on the underlying reasons that resulted in these ordinal scores, please refer to Appendix J, section J.1.

8.2.3 Importance of criteria

Not all criteria are equally important to the Ministry, and this should be taken into account when performing MCDA. For the purpose of applying the ARGUS method the criteria are each assigned an importance level, which is indicated by Table 14. Please refer to Appendix J.2 for an explanation of the degrees of importance that were assigned to the different criteria.

Degrees of importance
Not important
Little important
Moderately important
Very important
Extremely important

Criteria	Importance
Short-term efficiency	Extremely important
Attractiveness of renewables	Extremely important
Proportionality	Very important
Facilitate existing production	Little important
Discourage new excess capacity	Very important
Vulnerability strategic bidding	Very important
Efficient transmission signals	Little important
Compliance institutional framework	Moderately important
Non-discrimination	Very important
Simplicity and transparency	Little important
Influence when no congestion	Very important

Table 14: Degrees of criteria importance

8.2.4 MCDA results

In order to determine the desirability of each of the four congestion management methods, on the basis of their individual performances as were shown in Table 13, the ARGUS method compared all methods using pairwise comparisons. The nature of the decision-making problem required these comparisons to be performed in a pairwise manner, because the scale of the data (scores and weights) was ordinal. As a result it was not possible to create a single ranking table that calculates a fully aggregated total score for each method, on the basis of which the methods are ranked and the 'best' method is identified. This would have required the data to be quantitative (or at least quantifiable), which was not the case.

Figure 10 presents the results of the ARGUS analysis in a schematic form. The circles represent the four congestion management methods that were evaluated and the arrows indicate which method is better than the other (e.g. APX was found to be better than MS). Most importantly, this pairwise comparison using ARGUS has shown that it is not possible to conclude whether basic system redispatch is better or worse than market splitting, market coupling, or the APX-based method. The objectives of the Ministry, taking into account its priorities with respect to these criteria, are met by the evaluated congestion management methods to a different degrees, but there is not a single method that is better able to achieve these objectives than all others.

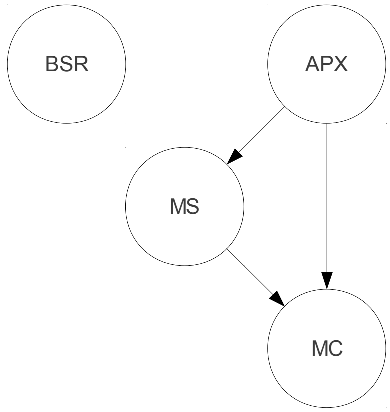


Figure 10: Outranking relations

Indifference between basic system redispatch and the other methods

Although one can conclude that – given the priorities of the Ministry (i.e. criterion importances) – the APX-based method is a more appropriate method to manage congestion in the Netherlands than market splitting or market coupling, as indicated by Figure 10, no statements can be made as to whether basic system redispatch performs better, worse, or equal to any of the other congestion management methods evaluated. Perhaps the most interesting conclusion one can draw from this finding is that the hypothesis that market-based methods outperform non-market based methods, which was implied in section 2.1 and based upon existing literature, cannot be held valid on the basis of the available data and (current) objectives of the Ministry. The reason why basic system redispatch was not found to be better, worse, or equal to the other methods is caused by its worse performance with respect to the long-term incentives it creates and its vulnerability to strategic bidding (see *Combined Preferences with Weights* tables under sub-sections 1, 2, and 3 – which compare basic system redispatch to market splitting, market coupling, and the APX-based method, respectively, in Appendix J.5). These criteria are held to be very important by the Ministry, but insufficiently adhered to by basic system redispatch when compared to the performances of the other methods.

Given these results, it is impossible to recommend the implementation of one particular congestion management method for the Netherlands. In order to obtain more conclusive results from multi-criteria decision analysis, two issues must be addressed. First of all, the conclusive value of the simulation results, which were used to score the methods for several criteria included in MCDA, is limited as a result of the model limitations (see section 4.6) and scenario assumptions (section 5.3) these rely on. Further research that applies a broader scope and uses a more extensive simulation model that corresponds therewith, could enhance the value of these model results and thereby improve the decisiveness of MCDA outcomes. The second issue that needs to be addressed is related to the objectives of the Ministry, which were found to conflict within the methods that were evaluated. In order to improve the MCDA process at this point, the Ministry is advised to reassess its objectives and reconsider the degrees of importance it attaches to the set of criteria.

Section 8.3 will provide a deeper analysis of these information limitations and conflicting policy objectives, by discussing the specific elements that contributed to the inconclusiveness of the MCDA process and by specifying the steps that could be taken in order to obtain more decisive results.

As an alternative to the above, the Ministry could design a completely new congestion management method, that is more capable of achieving its policy objectives than the existing methods considered in this study. This approach is considered unfruitful, however, given that Hakvoort et al. (2009) have already come up with several alternative congestion management method designs, none of which was eventually implemented.

8.3 Remaining knowledge gaps and policy choices

Multi-criteria decision analysis has taught that given the current policy objectives of the Ministry, it is not possible to clearly distinguish a method that outperforms the other methods evaluated in this study. As has already been discussed, this is (to some extent) caused by conflicting criteria, i.e. the situation where the Ministry assigns a high degree of importance to multiple criteria, whereas none of the methods scores sufficiently well on all of these characteristics. In order to provide a clear recommendation as to which congestion management method is most appropriate for the Netherlands, additional analysis is required in order to make a better distinction between the methods. This section will discuss what this additional analysis entails, and will do so by distinguishing two categories of additional analysis. On the one hand there are knowledge gaps, which represent issues that are not yet fully clear and where the outcome of further research could provide for a better distinction of the methods or criteria priorities. On the other hand there are policy choices, which require the Ministry to review the desirability of its objectives, or the prioritization thereof, before a better distinction can be made with respect to the appropriateness of the methods.

8.3.1 Knowledge gaps

Financial compensation schemes for renewable energy under market-based methods

The most important conflict that was found while performing MCDA was that none of the methods were able to combine a good performance with respect to fulfilling the objectives of maintaining a sufficient level of attractiveness of renewables on the one hand, and discouraging new capacity from being constructed in areas with excess capacity (creating the right long-term incentives) on the other (see Table 13). Although the market-based methods evaluated preclude prioritizing renewables, section 8.1.4 discussed that a financial compensation scheme may compensate for the negative effects when applying such a method. It is currently still unclear, however, what such schemes would entail and which effect they have when applied in combination with a market-based congestion management method.

Vulnerability to strategic bidding

The ordinal comparison of methods with respect to their vulnerability to strategic bidding was done on the basis of the results from a rather narrow analysis, which was unable to produce conclusive, quantitative results with respect to the precise strategic bidding effects that could be expected (see section 6.3). To increase the validity of the results that can be obtained from multi-criteria decision analysis, the assessment of strategic bidding consequences needs to be performed on the basis of an agent-based model, which simulates an extended period of time and addresses the elements that were found to pose a deficiency during the modeling element of the current study (see Reflection).

Proportionality

Determining the proportionality of congestion costs and their allocation should be based upon two factors: the differences in congestion costs (allocation) that are created by the different methods, and the time such conditions are actually present eventually determine the congestion costs that arise for e.g. a year. Although this study provided a fairly adequate estimate of congestion costs for a number of scenario-conditions, on the basis of which some insight in the proportionality of methods was created, it is important to realize that the simulation model used by this study was unable to take into account the development of such costs over time. In order to compare the methods on a more accurate basis, additional research should be conducted in which the proportionality of methods is determined on the outcomes of a model that allows for simulation over an extended period of time.

Influence when there is no congestion

The relevance of the influence of congestion management methods when there is no congestion is related to the sensitivity of congestion to arise. In the extreme case that congestion would occurs 100% of the time, it would be irrelevant whether the method has an influence in a not-congested situation as this would never occur. Therefore, the less congestion actually arises, the more important this criterion becomes. In order to better assess its importance, a more extensive simulation model is required that is capable of determining the extent of congestion that exists in the system over an extended period of time. Using this information the degree of importance can be revalued to allow for a more decisive MCDA to be performed.

8.3.2 Policy choices

Need for provision of efficient transmission investment signals

Furthermore, a conflicting difference was found to be in the provision of efficient transmission investment signals. Although this criterion was assumed to have only little importance, the Ministry should consider whether it could drop this criterion altogether. De Vries & Hakvoort (2002) have convincingly argued that providing the right incentives for alleviating congestion in the long term to a TSO, inherently conflicts with providing such incentives to generators. The actions of these independent generators cannot be influenced by the government in a liberalized market, whereas the Ministry can, on the other hand, influence the behavior of TenneT because it operates in a regulated monopoly. It is therefore desirable to focus on generator incentives when implementing a congestion management scheme, and use other policy measures to ensure efficient behavior by the TSO (de Vries & Hakvoort, 2002).

Facilitate existing production

Decisions of independent generators to located new production units in areas that are further away from load centers (e.g. Maasvlakte and Eemshaven) and which may experience congestion in the near future, have been based on the existence of a 'copper plate' approach in the Netherlands. Basic system redispatch was implemented in line with this approach and is aimed at not negatively affecting generators in areas with excess production in case of congestion. Because it is not possible to discourage new investments in such areas without either discriminating between generators or affecting existing generators as well, the Ministry should reassess its priorities and decide which it holds more important. Unfortunately, the limited time available that was available during this study precluded this from being further analyzed.

8.3.3 Overview

A summarized overview of the issues that caused MCDA not to return a clear recommendation as to which congestion management method should be implemented in the Netherlands is provided below.

Knowledge gaps

- Possibilities to incorporate a (financial) scheme to compensate renewable energy sources for the negative effects of congestion when applying a market-based method.
- Assess vulnerability to strategic bidding more accurately using an agent-based model.
- Compare the proportionality of methods on the basis of better congestion cost estimates, taking into account their development over time.
- Reassess the importance of the criterion 'Influence when there is no congestion' on the basis of extended data on the actual occurrence of congestion.

Policy choices

- Apply alternative measures for guaranteeing an efficient level of transmission investments.
- Reassess the importance of facilitating existing production in areas with excess capacity.

8.4 MCDA conclusions

Although this study did not result in the recommendation for a specific congestion management method for the Netherlands, it has provided an important insight into the main complicating factors with respect to this decision. Multi-criteria decision analysis using the ARGUS method revealed that some objectives of the Ministry are impossible to combine using a single method. Also, this study shed some light on the criteria most sensitive to this decision and on the issues that require further analysis before a clear-cut recommendation can eventually be provided.

The inability to recommend a single most appropriate congestion management method for the Netherlands did, however, reveal that although no *better* alternative could be determined, basic system redispatch was also found not to be *worse* than the other methods evaluated. Given the European tendency towards market-based methods and the preference for such methods expressed in literature, one may carefully conclude that the policy objectives of the Dutch Ministry of Economic Affairs, Agriculture, and Innovation are different, and the valuation of congestion management alternatives is also different as a result.

9 Conclusion and recommendations

This chapter will provide the main conclusions and recommendations of this research project. Section 9.1 presents the conclusions to this report by discussing the knowledge and new insights that were found by answering the research questions that were central to this study. Subsequently, section 9.2 provides a number of policy recommendations and discusses the knowledge gaps that still remain and could provide a basis for further research.

9.1 Conclusion

With the introduction of a new connection policy, which allows generators to be connected to the electricity grid directly rather than having to wait for the required grid capacity expansions to be completed, TenneT expects congestion to arise in the Netherlands in the near future. For two main reasons, the Ministry of Economic Affairs decided that basic system redispatch should be applied to cope with congestion. First, the Ministry held the opinion that congestion should not affect market players, in order to guarantee efficient and effective functioning of the liberalized electricity market. Second, basic system redispatch was chosen because it could be implemented rather easily, which was required to make a quick implementation of the new connection policy possible.

The Dutch approach towards congestion management deviates from the current European trend towards market-based mechanisms, which are considered more efficient by various authors in scientific literature. Furthermore, it was argued that basic system redispatch could potentially lead to excessive congestion costs and is vulnerable to strategic bidding by generators. The objective of this study was to analyze congestion in, and congestion management options for, the Netherlands. This was done by evaluating the consequences of the application of basic system redispatch in the specific Dutch power sector and by comparing its functioning to three other congestion management methods – market splitting, market coupling, and the APX-based method that was developed by TenneT. The aim of this approach was to contribute to existing (scientific) knowledge by doing so on the basis of a quantitative model, that represented the specific conditions present in the Dutch power sector and relevant to congestion management.

The goal of this research project was to provide an answer to the following research question:

> *"What congestion management method is most appropriate for effectively managing transmission grid congestion in the Netherlands, while optimizing overall (economic) system efficiency within the constraints that follow from the objectives set for the Dutch power sector by the Ministry of Economic Affairs, Agriculture, and Innovation?"*

This research question was answered on the basis of the five sub-questions it is composed of. These are discussed in the remainder of this section.

1. ***What are the drawbacks of the basic system redispatch method that is currently applied to manage congestion?***

The main drawbacks of basic system redispatch (sub-question 1) were analyzed on the basis of existing literature and were already briefly discussed above. The method can potentially lead to large congestion costs and is theoretically vulnerable to strategic bidding. This is particularly problematic when congestion becomes structural, as is expected by TenneT, and congestion management must be applied on a structural rather than a temporary basis, which was an assumption that formed a part of the Ministry's decision-making considerations. These drawbacks of basic system redispatch, in addition to the desire of TenneT to get an insight in the congestion costs that it can expect when the method must actually be applied, formed an important driver for this study.

2. ***What market-based congestion management methods are available and what is their position in within the overall set of methods?***

Throughout existing literature a rich terminology is applied to refer to congestion management methods. This terminology, however, is often used in an inconsistent manner. Different authors refer to similar methods using different terms, or –although less common– the same phrase is used to refer to different methods. As an answer to sub-question 2, this study created a structured overview of congestion management methods, which classifies the available congestion management in six main categories:

1. Transmission capacity adjustments
2. Direct capacity allocation
3. Redispatch using market-based criteria
4. Auctioning of transmission rights
5. Price differentiation (to geographic area)
6. Demand-side measures

The methods considered in this study fall under categories 3 (basic system redispatch and the APX-based method) and 5 (market splitting and market coupling). The scope of the quantitative modeling study, the results of which are discussed below, was limited to these four methods. Basic system redispatch was included within the scope of this study because it will be actually implemented and will actually be used to manage congestion in, at least, the near future, and the APX-based method was included because it was developed by TenneT as an alternative that takes into account several important criteria of the Ministry. Because a current trend towards market-based methods was identified with respect to congestion management in Europe (category 5), particularly on the basis of the methods market splitting and market coupling, these were included to allow for a comparison between non-market-based and market-based methods.

3. What effects are these methods expected to have in the Netherlands?

A quantitative modeling study, in which the Dutch electricity system was simulated under peak load in the year 2016, has shown that congestion in the Netherlands will primarily arise because of excess production capacity in the Maasvlakte area. As a result of the completion of several new production units, electricity in this area will be produced at a relatively low variable cost level. This results in the creation of transmission flows to other parts of the country and abroad, which particularly in the case of imports from the United Kingdom may cause congestion in the Dutch transmission grid. However, even under the rather extreme scenarios the model was made subject to, this congestion could be alleviated while creating only a small loss of social welfare. Table 15 shows the allocation of congestion costs for each of the methods under the *Low wind availability in Germany* scenario:

	Congestion costs	**BSR**	**MS**	**MC**	**APX**
Low wind availability in Germany	Consumers - NC zone - C zone	 € 0 € 0	 € 1,258 € 0	€ 1,258	 € 0 € 0
	Producers - NC zone - C zone	 € 0 € 0	 € 5,305- € 0	€ 5,305-	 € 231- € 0
	TenneT - National - International	 € 231- € 0	 € 4,792 € 975-	 € 4,792 € 487-	 € 0 € 0
	National SW	**€ 231-**	**€ 231-**	**€ 256**	**€ 231-**
	Foreign TSOs	€ 0	€ 0	€ 487-	€ 0
	Total SW	**€ 231-**	**€ 231-**	**€ 231-**	**€ 231-**

Table 15: Congestion cost distribution (scenario 1) (in € / hr)

Basic system redispatch and the APX-based method directly transfer the cost of sub-optimal redispatch to one (type of) market player (TenneT and the not *constrained off* upstream generators, respectively). Market splitting and market coupling – which lead to the exact same dispatch and congestion cost distribution[46] – create large cost components, with some market players experiencing a benefit from congestion, whereas others are allocated a large cost. These cost components are an order of magnitude larger than the actual, net societal cost of congestion, and as a result these methods provide a much larger incentive discouraging generators from constructing production capacity in areas which already have excess capacity available. From a transmission system efficiency perspective, these market-based methods thus create a higher long-term system efficiency. This is consistent with findings from existing literature. However, because there are other societal objectives with respect to production unit siting decisions, excessive congestion costs which provide transmission-efficient incentives may have other, possibly socially undesired, effects. The scope of this study, and as a result the type of simulation model used, did not allow for these to be fully analyzed. Further research is therefore recommended with respect to the consequences, and the social desirability thereof, that would result from providing these geographical incentives for generators in the Netherlands.

4. ***What specific characteristics should a method possess for application in the Netherlands?***

In order to determine which congestion management method is most appropriate for the Netherlands, multi-criteria decision analysis was performed on the basis of eleven criteria, which were identified as important when considering congestion management methods. From a societal perspective, which the Ministry is assumed to represent, an appropriate congestion management method must take the following objectives into account:

- Achieve short-term efficiency (least-cost dispatch under congestion constraints)
- Maintain (or improve) the level of attractiveness for renewable energy investments
- Be proportional to the seriousness of congestion
- Facilitate existing production in areas with excess capacity
- Discourage new units from being constructed in areas with excess capacity
- Have a limited vulnerability to strategic bidding
- Signal an efficient level of transmission investments
- Comply with institutional and legal framework
- Be non-discriminatory regarding existing and new network users
- Be simple and transparent procedures and effects
- Have no influence when there is no congestion

Note that these criteria were not all held to be equally important during multi-criteria decision analysis, which is discussed below.

5. ***What method is most appropriate for implementation in the Netherlands?***

Because both the valuation of method performance on the criteria mentioned above, as well as the importance of these criteria could only be assessed on an ordinal scale, it was not possible to indicate and compare the performances of the methods in a quantitative manner. Instead, each possible pair of methods was compared using the ARGUS method, in order to define a full set of pairwise outranking relations.

The most important insight from determining these outranking relations is that, given 1) the available knowledge on the effects of the different congestion management methods, 2) the current objectives of the Ministry, and 3) the importance attached to achieving each of these objectives

46 Under Directive 2009/72/EC congestion must be dealt with as a national issue. TenneT must compensate the interconnected TSOs in case their congestion rents deviate from a uniform pricing situation when market splitting is applied. Because market coupling would be incorporated in the European market coupling mechanism, the notion of a uniform MCP in the Netherlands would cease to exist. See section 4.4.3.

(priorities), there is not a single method that outperforms all other methods. Although, on the basis of the aforementioned knowledge, objectives, and priorities, the APX-based method was found to be more appropriate for the Netherlands than market splitting or market coupling, it did not provide a conclusive answer with respect to the performance of basic system redispatch compared to the other methods. Given the European tendency towards market-based congestion management methods and the explicit preference of existing literature for such methods, one can conclude that the objectives of the Ministry in the Netherlands deviate from those elsewhere and assumed by literature.

Section 9.2 presents several recommendations that would allow for the multi-criteria decision analysis process to be improved in order to, possibly, obtain a more conclusive result through conducting additional research and by reassessing policy objectives.

9.2 Recommendations

This research project has provided a quantitative insight in the application of four different congestion management methods, but it also found that it is not possible to recommend one of these methods as the single most appropriate method for implementation in the Netherlands. Several knowledge gaps still remain, or were newly identified throughout the process of conducting this project and providing an answer to the research question. This section will present an overview of the most important recommendations with respect to congestion management in the Netherlands, as well as recommend further research in fields that were identified relevant for the topic of congestion management, and specifically its implementation in the Netherlands.

Generator and TSO incentives for efficient long-term behavior

The criteria of creating incentives for both generators and TenneT to behave long-term efficiently were found to inherently conflict, as the congestion management methods only create this incentive for one of these. On the basis of De Vries & Hakvoort (2002), who argued that efficient TSO behavior can also be achieved by means other than the distributive cost effects of applying congestion management, the Ministry and TenneT are advised to devise an alternative scheme to guarantee a sufficient level of transmission investments, and subsequently removing the criterion that the congestion management method provides these incentives itself.

In this light it is also advisable to reassess the objective of facilitating existing production capacity in areas with excess capacity. This objective conflicts with the objective of providing an incentive for long-term efficient investments. Also, if a scheme was devised which facilitates existing production but provides efficient investment incentives for new units, this would create problems as it would also discourage the decommissioning of inefficient units, as well as conflict with non-discrimination principles.

Further research

On the basis of additional research a better, possibly quantitative, assessment of the performance of congestion management methods can be made, and differences in criteria importance can be better distinguished. This will improve the results that can potentially be obtained from conducting MCDA. The following topics were found relevant to be addressed:

- Possibilities to incorporate a (financial) scheme to compensate renewable energy sources for the negative effects of congestion when applying a market-based method.
- Assess vulnerability to strategic bidding more accurately using an agent-based model.
- Compare the proportionality of methods on the basis of better congestion cost estimates, taking into account their development over time.
- Reassess the importance of the criterion 'Influence when there is no congestion' on the basis of extended data on the actual occurrence of congestion.

The data obtained from this research will allow for a better distinction to be made between the available methods, and thus contribute to deciding which method should be applied to manage congestion while meeting the societal objectives for the electricity sector in the Netherlands.

Reflection

This report presented the results of a five-month research project on the topic of congestion management and its application in the Netherlands. Although this research has been fruitful in terms of the new insights, knowledge, and policy recommendations it created, a number of obstacles were encountered during the process as well. These obstacles were primarily related to the modeling element that formed a major part of the project, with data being sometimes difficult to obtain or because inherent limits of the modeling approach became apparent.

This chapter will reflect on the research process that eventually led to the results presented throughout this report. It will discuss the value these results provide for TenneT, elaborate on the model and the modeling process, evaluate its decision making effectiveness, and, to conclude, discuss how a different approach would have affected the results.

Usability for TenneT

When the project was initiated in December 2010, the decision to implement basic system redispatch to manage congestion in the Netherlands had already been made. It was still unclear, however, what financial consequences its application would have for TenneT. A key requirement from the study was therefore to provide a cost estimate on the congestion costs TenneT could expect to arise once the mechanism would enter into force. The quantitative model that was created for this purpose (among others) was fairly successful with respect to addressing this issue. It has determined the congestion costs to be small under all scenarios that were found to cause congestion in the Netherlands.

It is important to point out, however, that this model could only determine the costs that would arise under specific scenario conditions. It was not able to provide TenneT with a complete indication of congestion costs for a period of e.g. a year, nor was it able to determine how these are expected to develop. This was caused by the static nature of the model, which has already been discussed to be its main deficiency in section 4.6, and will be discussed more extensively in the remainder of this chapter. However, considering that each of the four scenarios that were simulated included extreme conditions, the mere finding that none of these scenarios resulted in high congestion costs nevertheless provides interesting information on the situation of the Dutch electricity market. In addition, the model that was constructed during the project is a useful deliverable by itself. This will *inter alia* be further discussed in the next section.

Reflection on modeling

One of the core elements of this research project was the construction of a model that would be capable of simulating the application of different congestion management methods in the Dutch power sector. At the basis of constructing this model lay the notion that the characteristics of physical production capacity are a highly influential factor for dispatch patterns and, as a result, transmission flows. Because slight differences in cost structures of production units located in different locations can greatly influence transmission flows, all generation units were included in this model separately. This approach turned out to be valuable, because it allowed for conclusions to be drawn on specific aspects of the Dutch electricity sector that would otherwise have been impossible to properly analyze. Also, this approach allowed for strategic bidding analysis to be performed using realistic data.

The main shortcoming of the model, however, lies in its inability to simulate developments over a period of time. Due to its static nature it is only able to calculate market outcomes, dispatch decisions, and transmission flows for a single round of market clearing, i.e. for one hour. As a consequence, the model is unable to calculate the expected congestion costs that would arise in the Netherlands during the period of e.g. one or several years, which limits the deterministic value of its outcomes. Although congestion costs can be determined for particular situations, the value of this is limited without knowing how often every such conditions will occur over a period of time.

At the start of this research project, the modeling intention was to construct a model that could determine how congestion and congestion costs would develop over time in the Dutch electricity system. Although the notions of 'static' and 'dynamic' models had not been explicitly considered, the implicit intention of this approach was to create a dynamic model that fully captured all aspects relevant to congestion management, ranging from realistically capturing all market processes to including detailed transmission system characteristics, which would allow to draw conclusions on the consequences that different congestion management methods would have when applied in the Netherlands. This vision soon turned out to be impossible to achieve within the time constraints that the project was subject to, and required that focus was placed on specific element.

Instead of creating an extensive model that would capture the entire Dutch electricity sector, the focal point of the project was narrowed down to the development of models to simulate the market mechanisms that are applied by the congestion management methods. This choice was made on the basis of the idea that once the market models were completed, they could (later) be incorporated in a network model. By adding a component that is capable of providing environmental conditions to this combined model, one would be able to obtain a model similar to the one that was originally envisioned.

At this point of the modeling process, it had become clear that these market models alone would constitute 'static' models, which would in a later stage later become part of a dynamic model when combined with a load flow model and scenario component. What I did not realize in time, and expected to solve by applying different scenarios, was that this would lead to limited applicability of the model outcomes. Although the use of scenarios provides a means to test these static models under extreme conditions, that were suggested by TenneT, it is impossible to test so many scenarios that their combined results have the same validity as continuous simulation. Furthermore, the difficulty of evaluating the effects of strategic bidding became apparent. The scenarios allow for an insight to be created in the *possibilities* for generators to bid strategically, but capturing learning effects (and possibly other effects, such as competition authority influence, network relations, etc.) is utterly impossible.

The realization that the model would be unable to produce the conclusive, and perhaps even some “shocking” results, was in a sense a disappointment. Nonetheless, I believe that the modeling process was valuable, both in terms of learning as well as the results it produced. The alternative approach to congestion management modeling, which included all independent generators and their units separately, and thus allowed for analysis at the level which really determines market outcomes, has proven its value and could in addition serve as a basis for further research.

Modeling assumptions

In addition to the inherent model limitations discussed above, it is important to point out some of the assumptions that were made during the model construction process, either because insufficient data was available, or in order to allow for certain model aspects to be simplified. An understanding of the assumptions a model relies upon provides knowledge on its area of applicability and the degree of uncertainty that should be considered when interpreting its results.

The single-round simulation of market clearing processes inherently assumes that such rounds can be simulated independently in the first place. In reality, however, the market and system conditions of the hours before and after the simulated round, have an influence on the round itself. The marginal cost of production is assumed to be determined solely on the basis of fuel and emission costs, which are provided as input factors and used to calculate marginal production costs using data on plant efficiency. In reality, however, the marginal cost of production also depends on whether a plant was already running during the hour preceding the hour that is simulated, and also whether the generator desires it to be running the next. Ramp rates, which cause start-up delays and costs, are essential factors to consider when submitting offers to the market. Both history and future thus influence at what cost a generator is willing to dispatch one of its units, but as the model reduces these considerations to the factors that can be determined for the single round of market clearance.

A second important set of assumptions is related to the simplification of the technical characteristics of the transmission grid. Most importantly, the grid is assumed to only transport "real Megawatts" between nodes (depending on their internal differences in production and consumption), its power flow calculations are rough, and the nodal approach considers only four locations throughout the Netherlands where electricity is produced and consumed. Its results should therefore not be relied upon when dealing with, for instance, operational grid planning, as this requires fully accurate grid data in order to ensure grid safety and reliability.

These assumptions could be made, because the purpose of the model was to obtain an order-of-magnitude insight in the different financial effects of applying different congestion management methods. It mainly dealt with the functioning of electricity (congestion) markets and primarily required the transmission system simulations to provide input data for these market clearing processes.

Decision making effectiveness

The objective of this research project was to recommend a suitable congestion management method for application in the Netherlands, given the constraints following from (societal) objectives set by the Ministry of Economic Affairs, Agriculture, and Innovation. This was done using multi-criteria decision analysis, applying the ARGUS method which was deemed suitable for the nature of the data that were available.

The outcomes from quantitatively evaluating the methods using a simulation model were expected to play a crucial role during this analysis. The static nature of the model, however, affected the area of applicability of the model results, which are only valid under a limited range of conditions and are therefore not conclusive. Also with respect to the other aspects of the multi-criteria decision analysis that was performed, improvements could be made to obtain more conclusive results. If more time would have been available for this aspect of the project, it would have been possible to challenge the objectives that are considered important through extensive discussions with stakeholders, with content being provided by existing literature and model results. Also, this could have improved the assessment of criteria importance, which has a large influence on MCDA outcomes.

Given these limitations, it is important to interpret the results from MCDA as being indicative only. Although they provide interesting insights, which could serve as a basis for further research but also as input for decision making discussions, they should not be considered as providing the single right answer. (Actually, the analysis did not result in a single right answer: its main conclusion was that it remained inconclusive; see section 8.2.4.)

Alternative approach

Above I have already discussed that the limitations of the modeling approach had an influence on the conclusiveness of the the project results. The narrow area of applicability of the quantitative results produced by the model caused that it was not always possible to make firm statements with respect to the research questions that were key to the project. Rather, conclusions sometimes needed to be accompanied by an explicit delineation of their applicability.

An alternative approach could have focused on the main cause of these inconclusive results, which were related to the model's inability to simulate over time. However, only incorporating this would not be sufficient by itself, as such type of model would have required extensive data in order to produce valid results (mostly on environmental factors, which influence the system over several years). This would have taken time away from other model elements, potentially resulting in a case of *one step forward, one step back*.

In order to produce more conclusive results, while avoiding the pitfall of only *shifting* the focus rather than *broadening* it, I could have narrowed down the geographical scope of the study. As the model results have shown, congestion is primarily expected to arise on the grid infrastructure connecting the Maasvlakte to the rest of the Netherlands. As a result of the geographical scope that included all of the Netherlands, plus additionally four interconnections, a lot of time was spent on modeling the Dutch transmission system. This required defining nodes, nodal borders, obtaining the right transmission system data, processing this data and using it to calculate PTDFs, incorporating expected grid developments, all in all consuming quite a lot of time. A mere focus on the Maasvlakte – Ring infrastructure would have simplified the required grid data and calculations, and would have allowed for more detail and depth to be added to other aspects of the project.

Conclusion

The five months I spent researching the topic of congestion management have not only taught me a lot about the topic itself, but also about the process of researching it. Time is crucial, because although at first a period of five months may appear to be sufficiently lengthy to solve all of mankind's problems, I'm probably not the first one to have experienced that it is not. The current chapter has discussed how choices were made and how these affected the project. Although some of the (type of) results produced by the project were expected to be different at the beginning, it has nevertheless led to interesting new insights, created a basis for further research, and provided an important component for a future model that does not yet exist, but could prove to be valuable for a variety of uses, in addition to evaluating congestion and the methods to manage it.

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Glossary

Term	Definition
BritNed	International 1000 MW submarine HVDC transmission link connecting the Netherlands (at Maasvlakte) and the United Kingdom (at Isle of Grain) (operational: 2011).
Congestion	The situation in which a power line has reached its limits of safe operation, as a result of which requests for deliveries by market players (transactions) cannot be physically implemented as requested (also see section 1.2.1).
Constrained off capacity	Production capacity located in an upstream congestion region (with excess capacity) that was intended to produce electricity on the basis of the market outcome, but which cannot do so as a result of transmission constraints. Also see **constrained on capacity**.
Constrained on capacity	This is the capacity that was originally not dispatched on the basis of the market outcome, but now needs to be dispatched after all to compensate for the **constrained off capacity**.
Congestion region	For the purpose of applying congestion management methods this study distinguishes four regions in the Netherlands which are considered to have sufficient transmission capacity in place to accommodate internal flows. Congestion can still occur between them, as capacities are limited. These areas are called “congestion regions” during this study.
Congestion zone	A congestion zone is a combination of one or more nodes that, for the purpose of applying a congestion management method, are considered to have sufficient transmission capacity available to accommodate internal flows, but where congestion can occur with another congestion zone (also a combination of one or more congestion regions). Please note the difference between a congestion zone and a **congestion region** (see above).
Distribution grid	Distribution grids transport electric power from the **transmission grid** to smaller end-users such as households. Because distances are usually smaller, these are operated at lower voltages (below 50 kV) than the transmission grid.
Downstream area	The congestion zone with a net electricity import (generated in the upstream area).
Emission right	Electricity producers (among others) may only emit particular pollutants if they acquire sufficient right to do so. These rights can be traded on the market, which is meant to reduce emissions in an economically optimal way. The requirement to possess such rights applies to various pollutants, such as CO_2 and NO_X.
Generator	Entity that owns, or otherwise solely operates, physical production capacity, and (can) sell its electricity on the market, either by itself or through a supplying intermediary. (Also see **Supplier**.)
High voltage grid	See **Transmission grid**.
Lignite	Brown coal
Merit order	Economically optimal order of unit dispatch, generally depending on marginal production costs (taking into account all cost factors, incl. e.g. start-up costs).
N-1 safe capacity	Capacity of a transmission segment that is still available when a single contingency failure occurs. TenneT is required to operate the 380 kV grid under N-1 safe conditions at all time, which means that if any circuit were to fail, power supply is not interrupted anywhere.
NorNed	International 700 MW submarine HVDC transmission link connecting the Netherlands (Eemshaven) and Norway (Feda) (operational since 2008).
Peak load	Highest simultaneous consumption of electricity by a consumer or a group of

	consumers (e.g. per congestion region).
Program responsible	An entity with **program responsibility**.
Program responsibility	Electricity generation must be equal to consumption at all times in order for the electricity system to function. Entities with program responsibility must ensure that their production and consumption, or the production and consumption of the actors they represent, is balanced at all time, or take measures to ensure this is the case. They are financially liable for the imbalance costs that arise when this balance is not maintained.
PTDF	Factor representing the proportion of electricity following a particular path when multiple power lines are available for the power flow. Determined by the **reactance** of grid elements.
Reactance	Opposition of a grid segment for a change of its current or voltage. Simply stated the reactance characteristics of the elements present in the electricity grid determine how power flows through a meshed network. It is expressed by X [ohm] or x [ohm/km]. Also see **PTDF**.
Retailer	Electricity market customer acting on the market on behalf of a number of (usually small) electricity consumers, such as households.
Social surplus	See **Total social welfare**.
Supplier	Entity supplying electricity to the market, either bilaterally or through spot market auction. A supplier needs not have physical production capacity in place. (Also see **Generator**.)
Surplus	For consumers: the difference between the economic value of electricity and its actual cost (MCP), multiplied by the volume purchased. For producers: the difference between MCP and the generation cost of electricity, multiplied by the volume produced. For TSOs: the revenues from congestion rents and/or costs related to redispatch
Total social welfare	The sum of all consumer, producer, and TSO surpluses.
Transmission grid	This is the electricity network infrastructure that is used to transport electricity over larger distances, using high voltages (above 50 kV) to reduce network losses. **Distribution grids** are connected to the transmission grid to deliver power to (smaller) end-users, such as households, whereas large producers and customers are often directly connected to the transmission grid.
Upstream area	The congestion zone with a net electricity export (consumed downstream).
Wind factor	Wind turbines have a rated capacity, but whether they actually produce at this capacity is dependent on multiple factors, primarily the wind speed. The wind factor, which is a value between 0 and 1, determines the actual production level of a turbine as a share of its rated production capacity.

Appendix A: Congestion management methods found in literature

This appendix elaborates on the various categories of congestion management methods and other measures to deal with transmission constraints that were presented in section 3.1.

A.1 Approach

Overviews of congestion management methods are provided by various literature sources (Brunekreeft et al., 2005; Copenhagen Economics, 2006; Hakvoort et al., 2009; Kristiansen, 2007b). However, for various reasons (scope, antiquity, author background, quality) these overviews are generally found to be incomplete. On the basis of such overviews and literature regarding specific methods I have tried to come up with an overview that is as complete as possible.

A.2 Overview of literature

The table below provides an overview of the literature that was reviewed for the purpose of constructing a categorized overview of congestion management methods. For each literature source I will briefly describe the information that was provided with respect to congestion management methods and categories thereof. Congestion management methods discussed are underlined (terminology as used by the source). Some instances include additional comments on interesting information, including, but not limited to, deficiencies or limitations of these sources (e.g. wrong or incomplete information) that were found and required further research. Note that the "Information Provided" column does not serve as a summary of any kind, but merely contains the relevant information that was extracted from the article for the purpose of constructing the overview of congestion management methods.

As a final note before presenting the table itself: what is illustrative for the need of constructing this overview becomes visible when one looks at the wide variety of terms that are underlined in Table 16. The scientific contribution of a structured overview of these methods, such as provided below in section A.3, becomes almost self-explanatory when one realizes that all these terms are used throughout literature to refer to the available congestion management methods and other measures to deal with transmission constraints.

Author	**Information provided**	**Additional comments**
(Bartholomew et al., 2003)	Discusses the efficiency of the New York <u>transmission congestion contract</u> (TCC) market, where a <u>financial point-to-point transmission rights auction</u> is used to manage congestion. <u>Nodal pricing</u>, <u>flowgate rights</u>, <u>firm transmission rights</u> (FTRs).	Congestion management methods discussed are purely financial.
(Bjørndal & Jörnsten, 2007)	Quantitative analysis on the effects of partitioning the Nordic electricity market differently and applying a combination of <u>zonal pricing</u>, <u>market splitting</u>, and <u>counter-trade</u>.	<u>Zonal pricing</u> may lead to a reduction in social surplus in comparison with <u>nodal pricing</u>, but its simplicity may offset this reduction. Article did not consider strategic bidding.
(Brunekreeft et al., 2005)	European interconnection appears to be hampered by either their management or insufficient capacity. Locational signals need to be provided to trigger investments efficient from a transmission perspective. <u>Decentralised auction</u>, <u>coordinated auction</u>, <u>market coupling</u>, <u>nodal pricing</u>, discussed.	US regulators require generators "to submit cost-based bids if their market bids distort dispatch" (p. 78) as a means to deal with market power. Transmission capacity underutilized due to conservative estimates by TSOs

	Locational marginal pricing and deep connection charges, preferably on a European level could improve efficiency but are politically difficult to achieve. Nodal spot pricing is the most efficient CM-system, but zonal (country-wide) approaches are used in Europe.	dealing with flows originating from and flowing to third countries. Less conservative estimates could jeopardize system security.
(Camfield & Schuster, 2000)	Transmission should be efficiently priced. The article argues what efficient pricing entails and discusses issues related to its implementation. Congestion is to be managed by dispatching least-cost generators on the basis of complete ISO information. Locational marginal pricing is also put forward to price transmission capacity efficiently.	
(Copenhagen Economics, 2006)	Methods for TSOs to "manage bottlenecks". Capacity expansion, market splitting, counter trade, capacity adjustments.	Incomplete overview. Mixed application of terminology on different levels.
(Cowart, 2001)	Discussion of the role of demand-side management (DSM) to allow electricity systems to cope with peak demand and transmission constraints. The article also discusses transmission system congestion relief by means of location specific pricing, transmission loading relief, and socialization through uplift charges.	Socialization through uplift charges is similar to system redispatch introduced in section 1.3 of this report.
(Creti et al., 2010)	Analysis of increasing degree of European market integration and the position of Italy in this. Transmission pricing between markets appears to be zonal pricing everywhere.	
(Ehrenmann & Smeers, 2005)	Comparison of various CM-methods with illustrative quantitative examples: • Nodal [pricing] system, • Flowgate model/system (which "(...) implements the principle of locational marginal pricing [LMP].", p. 136), • Market splitting, • Decentralised market coupling, and • Coordinated auction.	
(Furio & Lucia, 2009)	Method to deal with transmission constraints in the Spanish wholesale electricity market. Article also discusses incentives for market players and possibilities for exercising market power.	
(Førsund et al., 2008)	It is important that possible electricity flows that are the result of wind power availability are taken into account in network planning. Yet, coordination between generation and network capacity investments has been limited in Norway. This could lead to the crowding-out of hydro power, which would not lead to a total increase in renewable	

	energy use. Transmission costs should be incorporated in the location decisions of producers. (Geographical differentiation in) transmission use-of-system charges and locational electricity prices could achieve this.	
(Glachant & Pignon, 2002)	TSOs in Europe might distort cross-border congestion data if they can benefit from such a distortion at the benefit of other TSOs and/or society. The authors focus on the Nordic market as an example, and find that the institutional arrangements used do not “solve the incentives problem in coordinating TSOs” (p. 23). Systems where nodal pricing is used potentially enable system operators to profit by manipulating network constraints.	
(Glachant & Pignon, 2005)	Article on TSOs signalling congestion to market participants. Methods discussed: market splitting and counter-trade.	
(Graves & Clapp, 2001)	Tariff regulation of transmission systems. Performance-based regulation of for-profit transmission.	Article provides an argumentation for market-based transmission system investments and does not particularly discuss different congestion management alternatives.
(Hakvoort et al., 2009)	Analysis of various methods (market agent, basic system redispatch, system redispatch with cost pass-through to generators, hybrid redispatch, market redispatch, market splitting in two zones).	Scope of methods was limited due to scope limitations of the study (only focused on those quickly implementable; see p. 10 for all assumptions underlying project scope)
(Hers et al., 2009b)	Quantitative analysis of similar methods as in Hakvoort et al. (2009).	
(Hiroux & Saguan, 2010)	Analysis of wind power support schemes in the light of liberalized markets and locational incentives with respect to transmission system operation.	
(Johnsen et al., 1999)	Comparison of prices in the Norwegian market under constrained and non-constrained conditions to analyze whether market power in the day-ahead market can better be exercised during constrained periods. The report focuses on two aspects, zonal pricing and demand-side bidding. Enhanced opportunity for market power appears to exist as markets are smaller and more concentrated when constrained.	
(Kawann & Sakulin, 2000)	The article introduces the line flow splitting method to manage congestion which should allow for simple transmission service valuation, differentiated to location. It allows for compensating generators that relieve congestion by imposing counter-flows in a congested network.	At the end of the article the authors recommend to increase transmission capacity whenever possible, in order to increase competition in electricity generation. They do not discuss the cost-benefit trade-off which sometimes applies, though.
(Kristiansen, 2004)	Current practice of congestion management	'Market splitting' referred to as 'area

	and transmission pricing in the Nordic electricity market. Overview of transmission tariff structures in the Nordic region.	price model'.
(Kristiansen, 2007b)	Rather good categorization of methods in market-based and non-market-based categories, the former being further specified in implicit auctions and explicit auctions, and the latter in access limitation, priority list, pro-rata rationing, reserve price auction, and retention.	Some methods mentioned but not included in the author's overview (e.g. "redispatch", which is similar to "system redispatch" as in Hakvoort et al., 2009) because considered as measures to manage real-time imbalances only.
(Kristiansen, 2007a)	The allocation of cross-border capacity is generally allocated in Europe using cross-border auction trading. This explicit auction mechanism separates transmission and electricity trade. Market splitting is used in the Nordic market. The article analyzes the German-Danish connections (explicit auctions) and finds that the auctions do in reality not reflect the underlying value of the asset and substantial variations occurred in CM fees.	
(Lesieutre & Eto, 2004)	Interesting article on congestion costs and inconsistencies in their calculation when comparing various studies.	"Congestion costs may rise as a result of reducing congestion" (p. 69).
(Leuthold et al., 2008)	Increased transmission problems are expected as a result of increased wind power capacity in Germany. The authors argue that scarce capacity should be allocated using a nodal price approach, which according to them is superior to a uniform pricing approach. Zonal pricing is also discussed and found to create more administrative rules, poorer incentives for investments, demands to pay generators not to produce, and more complicated to define zones than nodes.	Nodal pricing does not necessarily provide incentives for the TSO to expand capacity. This needs to be taken into account by combining its implementation with appropriate incentive regulation.
(Neuhoff, 2004)	Integrated transmission auctions and energy spot markets (implicit auction, eds.) reduce possibilities for exercising market power compared to when these are separate markets (explicit auction, eds.).	If transaction costs and liquidity are ignored, the outcome for both approaches is equal.
(Pérez-Arriaga & Olmos, 2005)	Article proposes a coordinated explicit auction of transmission capacity. Market participants that wish to carry out transactions that cross borders should participate in a point-to-point rights auction. The method is compared with a "conceptually ideal" (p. 132) coordinated implicit auction, which is used as a reference model. Flowgate-rights auctions are also discussed but found inferior to point-to-point rights auctions.	The article ignores issues related to the exercise of market power.
(Pignon, 2002)	Article compares market splitting and counter-trading with the Nordic electricity market (Norway and Sweden in particular) as	

	an example.	
(Rious et al., 2008)	TSOs are designed very differently around the world. Three CM-methods are identified: nodal pricing, redispatching, and zonal pricing. Various grid cost allocation tariff schemes/methods are also discussed: deep cost allocation, shallow cost allocation, and zonal allocation.	
(Rosenberg, 2000)	Argument against locational marginal pricing, which is argued to create excessive costs for users because prices are divorced from the actual value of transmission services, prices can exceed redispatch costs necessary to relieve congestion, not sensitive to variations in the magnitude of congestion, and can create perverse incentives to increase congestion.	The article considers a situation where generation and transmission capacity is owned by the same party to be valid; this is not the case in the Netherlands.
(Rotger & Felder, 2001)	Article arguing that electricity transmission should no longer be considered a natural monopoly. Competitive solicitation process for private transmission investment. Locational-based marginal pricing (LMP).	
(Ruff, 2000)	Flowgate markets lead to very high transaction costs and market inefficiency according to the author. This is the result of market participants being forced to use flowgate rights (FGRs) to “assemble … hedges against so many things they cannot predict, understand or control” (p. 37).	
(TenneT, 2009d)	APX-based method developed internally by TenneT.	
(Turvey, 2006)	Article discussing the difficulties that arise from the interconnection of two or more areas that are served by different TSOs. Various CM-methods are analyzed: proportional allocation, first-come-first-serve allocation, counter-purchasing, market splitting, financial transmission rights auctioning, physical rights, superpositioning, auctions of multi-lateral transmission rights, Co-ordinated Re-dispatching Cost +.	Counter-trading referred to as counter-purchasing.
(Veit et al., 2009)	Quantitative agent-based analysis of market power in the German electricity system under conditions of congestion and different availability of wind power, using a zonal pricing mechanism.	
(Weigt et al., 2010)	Implications of large-scale wind power from North Sea parks for the electricity grid and prices, using zonal, nodal and uniform pricing approaches in modeling exercise.	Model assumes a competitive market and neglects strategic behavior.

Table 16: Literature used for constructing an overview of congestion management methods

A.3 Categorized terminology

On the basis of the literature overview in section A.2 I have categorized the various terms used for referring to methods to deal with transmission constraints in 5 groups: 1) physical capacity adjustments, 2) direct capacity allocation, 3) market-based redispatch, 4) explicit auctioning of transmission capacity, and 5) capacity allocation through market price differentiation.

The first iteration of this categorization effort brought some oversight to a field of research that lacks consistent terminology, but still contained a lot of different terms that were used to indicate a similar – or the very same – concept. Table 17 therefore uses the terminology that is used throughout this study but includes synonyms found in literature in *italics*.

1. Transmission capacity adjustments artificial capacity adjustments capacity expansion	**2. Direct capacity allocation** dispatching least-cost generators[47] *(redispatching, socialization through uplift charges)* first-come-first-serve allocation geographic differentiation in transmission use-of-system charges line flow splitting market agent approach priority list physical rights proportional allocation *(pro-rata rationing)* reserve price auction retention
3. Market-based redispatch basic system redispatch co-ordinated re-dispatching cost+ counter trade *(counter purchasing, counter trading)* hybrid redispatch market redispatch system redispatch with cost pass-through to generators	**4. Explicit auctioning of transmission rights** auctions of multi-lateral transmission rights coordinated auction *(coordinated explicit auction of transmission capacity)* cross-border auction trading decentralised auction explicit auction mechanism *(separate [transmission and energy] markets)* flowgate system *(flowgate market)* point-to-point rights auction
5. Capacity allocation through market price diff. APX-based method coordinated implicit auction *(integrated transmission auctions and energy spot markets)* market coupling *(decentralised market coupling)* market splitting *(area price model)* nodal pricing zonal pricing *(locational marginal pricing, locational-based marginal pricing, locational electricity prices, locational pricing, location specific pricing)*	**6. Demand-side measures** demand-side bidding transmission loading relief

Table 17: Congestion management terminology used in literature, categorized

Several congestion management methods found in Table 16 were not included found in this overview. Although included as a congestion management method by the respective author, they are neither considered to be separate methods to alleviate congestion, nor are they variants thereof, within the scope of the definition of *congestion management* used in this study. To a large extent this category consists of measures that deal with the implications of congestion on a financial level,

47 By a system operator on the basis of full information on (marginal) costs etc. (applied in US)

i.e. provide hedging against congestion costs for market players. These measures fall outside the scope of this study as they provide no solution to cope with physical network constraints. They are briefly discussed below.

Receipt-point-to-delivery-point obligations *(firm transmission rights, financial point-to-point transmission rights auction, financial transmission rights auctioning, transmission congestion contract)*	This method, referred to by a variety of names, allows market participants to hedge against congestion costs, usually the result of the application of nodal pricing or redispatching. These phrases were solely found in American literature.
Uniform pricing approach	Although it is an antonym of the phrase *nodal pricing*, which can be considered a congestion management method because it translates congestion costs into geographical price differences, uniform pricing is no congestion management method itself, but merely an approach to structuring electricity markets.
Superpositioning	Superpositioning indicates the act of imposing opposite flows to a single power line, thereby providing relief to congestion. Although relieving congestion, it is not included as a congestion management method because the manner in which such flows are created (i.e. redispatch of production units) has to be determined by another procedure (which can fall within any category). Although originally included as a congestion management method by Turvey (2006), superpositioning is thus merely a descriptive phrase within the scope of this study's definition of congestion management.

Table 18: Congestion management terminology not included as separate methods

A.4 Overview of methods to deal with transmission constraints

Because Table 17 still contains a mix of terms indicating single methods or "families" of methods, a structured overview is provided below to complete the literature structuring effort that answers the first part of sub-question 2 of this study. The methods are grouped and variants and/or examples of congestion management methods are indicated in bullets. This overview was presented in its entirety in section 3.1 and an explanation for some of its characteristics can be found below.

Active TSO intervention	
Transmission capacity adjustments	Artificial capacity adjustments Capacity expansion
Direct capacity allocation	Traders solve congestion • Market agent approach TSO solves congestion • Allocation of physical rights: priority list • Allocation of physical rights: proportional • Dispatching least-cost generators on the basis of complete information • Geographic differentiation in transmission use-of-system charges • Line flow splitting[48] • Reserve price auction • Retention

48 Using the line flow splitting method electricity transmission tariffs are related to the efficiency of grid use by consumers. However, physical congestion is solved by the system operator by redispatching generators (Kawann & Sakulin, 2000).

Redispatch using market-based criteria	Full TSO coordination • Basic system redispatch • Co-ordinated Re-dispatching Cost + • Counter trade • Hybrid redispatch • System redispatch with cost pass-through to generators Trader involvement/responsibility • Market redispatch
Market coordination	
Auctioning of transmission rights	Coordinated explicit auction (e.g. flowgate or point-to-point rights system)
	Decentralized explicit auction (e.g. auctions of multi-lateral transmission rights; cross-border auction trading)
Price differentiation (to geographic area)	Coordinated implicit auction • APX-based method • Market splitting • Nodal pricing • Zonal pricing Decentralized implicit auction • Market coupling
Demand-side measures	
Congestion solved by consumer reaction to situation	Demand-side bidding Transmission loading relief

Table 19: Structured overview of congestion management methods

The information in the table is structured in a grouping similar to the methods categorized in Table 17, which are shown in the left-hand-side column. The right-hand-side column contains the various methods, which are grouped whenever applicable. Synonyms, which were indicated in italics in Table 17, are not included here. Hence, the terminology used throughout this report is consistent with the terminology as used in Table 19. For a description of these methods, please refer to Appendix B.

One may notice that the market agent approach is grouped under *Direct capacity allocation* under 'Active TSO intervention'. Under this method market agents trade transmission rights in order to achieve an economically efficient outcome. Physical congestion is managed by means of proportional allocation of by the TSO, though, and therefore the method falls within this category, despite the fact that the concept – or even just its name – may suggest otherwise. Congestion management methods in this category either allow the TSO to directly intervene if required, or consist of a finite amount of transmission rights which sum up to maximum grid capacity. The latter could also be seen as a direct intervention method: the TSO sets the maximum in transmission rights single-handedly.

Furthermore, the methods included in the category *Redispatch using market-based criteria* are further grouped to 'Full TSO coordination' and 'Trader involvement/responsibility'. The latter group contains the market redispatch model developed by Hakvoort et al. (2009) and is grouped under 'Active TSO intervention' because although a part of the redispatch decisions are to be made by market players themselves, active intervention from the TSO is central to this mechanism.

Zonal pricing

The definition of zonal pricing deserves special attention, because it may be interpreted in two distinct ways: descriptive or prescriptive. Zonal pricing can, in its descriptive definition, refer to a situation where different price zones exist within a single market. In this definition it does not prescribe the manner in which transmission capacity and congestion cost are allocated, i.e. it is in itself not a congestion management method and only used to describe an outcome in which these zones are somehow distinguished. In its prescriptive definition on the other hand, it refers to a variant of nodal pricing in which two or more nodes are (permanently or occasionally) grouped and act as a single node (with equal prices). The coupled North-Western European electricity markets are an example of the former definition. They form a single market consisting of different price zones (the zonal borders of which are national borders) using both explicit capacity auctions and market coupling to manage congestion[49]. All scientific literature that was reviewed, however, assumes an implicit auctioning mechanism to exist whenever zonal pricing is applied, thus referring to the latter (prescriptive) definition.

This report will refer to zonal pricing in its prescriptive definition, i.e. as a variant of nodal pricing. Zonal pricing is similar to nodal pricing with the exception that zones can be defined as such that other congestion management methods are required to cope with congestion within these zones. Nodal pricing, by definition, refers to a situation where nodes are defined as such that the implicit pricing mechanism alone can solve congestion and other measures are only required in case of very exceptional circumstances and emergencies).

More information on this method is provided in Appendix B.2.2.

49 Since November 9, 2010 market coupling is the sole cross-border trade mechanism (and thus cross-border congestion management mechanism) for the North-West European region consisting of Belgium, Denmark, Estonia, Finland, France, Germany, Luxembourg, the Netherlands, Norway, and Sweden.

Appendix B: Description of congestion management methods

As discussed in section 3 and Appendix A, a rich vocabulary is used in existing literature, both scientific and non-scientific. Appendix A clarified the terminology that is used throughout this report, and the current appendix will, both for the sake of completeness and for those readers not familiar with these methods, briefly describe the methods introduced there. As was discussed in the research proposal (van Blijswijk, 2010) this description is brief, but includes references to existing literature sources where more information can be found (if necessary).

B.1 Active TSO involvement

The methods in this category all share the involvement of the TSO in mitigating the consequences of transmission constraints. Although some form of market mechanism might be used (this is the case for some of the methods discussed in B.1.3 and some in B.1.2) the key characteristic is that the TSO eventually needs to take action to solve congestion, as opposed to the methods described in appendices B.2 and B.3 where a market mechanism and customer measures, respectively, solve congestion themselves without the need for a TSO to actively intervene by running a market on which generators can offer constrained on and constrained off power. The spot markets that exist under these "true" market-based methods may be facilitated by the TSO, though, but it is important to recognize that this is not necessary – as opposed to the non-market-based methods discussed in the current sub-section.

B.1.1 Transmission capacity adjustments

Capacity expansion	
Perhaps the most basic measure to mitigate congestion is to increase grid capacity. By reinforcing the transmission network, the application of other measures can be made redundant.	
Advantages: Other 'complicated' methods become redundant	**Disadvantages:** Costly Long-term solution only Requires sufficient insight in future transport demand

Artificial capacity adjustments	
Physical electricity flow patterns are different from the flows contracted by market parties. In a large integrated network, congestion can arise in parts of the network other than those where electricity flows 'contractually'. TSOs can in some circumstances solve such congestion by declaring a smaller capacity on a particular line, which alters these contractual (and physical) flows of electricity as a result of which relief is provided to the congested network element. This solution is usually applied in an international context where two systems are interconnected. See e.g. Copenhagen Economics (2006).	
Advantages: Easy to apply	**Disadvantages:** Applied at the expense of trade capacity, resulting in less-than-optimal dispatch for the overall system

B.1.2 Direct capacity allocation

Allocation of physical rights: priority list	
Given the capacity of the grid, rights for its use can be awarded to grid users. When capacity is insufficient to meet transportation demand, capacity will be allocated to market players in priority order (for instance: a first-come-first-serve approach or on the basis of historical usage). Transmission rights can be awarded using a variety of procedures, criteria, and periods of time, and can be in the form of permanent rights or the use-it-or-lose-it principle. See e.g. Kristiansen (2007b), section 4.2.2, and Turvey (2006), section 3.3.	
Advantages: Easy to apply	**Disadvantages:** Congestion rents captured by market players

Responsibilities to meet demand are shifted to market agents	Discrimination of market players Favors traders with large portfolios of suppliers Limited transparency Probably leads to less-than-optimal dispatch

Allocation of physical rights: proportional	
Similar to first-come-first-serve allocation, except that *all* market players are awarded grid capacity in case of congestion, proportional to the demand requested. (Turvey, 2006, section 3.3)	
Advantages: Easy to apply Responsibilities to meet demand are shifted to market agents	**Disadvantages:** Anticipating congestion and allocation proportional to the capacity requested, market players can deliberately overstate their demand to be awarded more capacity than their competitors. Probably leads to less-than-optimal dispatch

Dispatching least-cost generators on the basis of complete information	
System operators can be given the authority to directly adjust production rates of (some) power plants in case congestion arises. This approach is common in the United States, but runs against “regulation culture” in the Netherlands (de Vries, 2010).	
Advantages: Market power cannot be exercised when congestion arises	**Disadvantages:** Creates principal-agent problem: SO needs to estimate actual costs, but only the producers really know these

Geographic differentiation in transmission use-of-system charges	
This method, applied in for instance Norway, entails the differentiation of transmission tariffs in order to better reflect true costs. Producers located far away from loads (or vice versa) can be made subject to higher tariffs in order to provide an incentive for new entrants to locate themselves more efficiently from a transmission perspective.	
Advantages: 'Fair' distribution[50] of transmission costs	**Disadvantages:** Longer-term solution only: locational incentive is provided, but the method cannot solve “acute congestion” Precludes application of 'copper plate' approach[51]

Line flow splitting
Line flow splitting is a financial measure that allows for an individual calculation of grid usage for each consumer and/or producer in order to pass-through congestion costs to those that create them. More information on the method is provided by Kawann & Sakulin (2000), although in their work the actual physical congestion is managed by means of another method in the category 'Active TSO involvement' (the article seems to imply 'Dispatching least-cost generators on the basis of complete information', although this is not the only option in my opinion).

50 Of course, perceptions on whether a location-based tariff is 'fair' depend on the value framework applied to the situation. One could argue that the cost of a locational decision that requires a TSO to reinforce its network should be borne by the producer creating this need, but on the other hand one could also argue that a producer is restricted in its ability to freely choose the location of a production facility and can therefore not be held responsible for a less efficient location.

51 Opponents of this approach would categorize this characteristic under 'Advantages'. It is included under 'Disadvantages' nevertheless, in line with the Ministry's (and producers') preferences.

Advantages:	Disadvantages:
'Fair' distribution[52] of transmission costs	

Market agent approach	
The TSO reduces transport rights of generators if congestion occurs (in the most neutral way this is done proportionally) in order to solve congestion. Market players can then trade these rights and it is expected that cheap generators will be willing to pay more for these rights than expensive generators. Thus, the market agents themselves create an economically efficient dispatch of plants. More information can be found in Hakvoort et al. (2009), section 4.2.	
Advantages: Avoids market power problems Market determines efficient way to solve congestion	**Disadvantages:** Inefficiencies in trading these transmission rights may arise, shortly after introduction in particular

Reserve price auction	
Traders bid for capacity in an auction, but an initial price level is set to start bidding from. Although seemingly an explicit auction, the method (which is very briefly explained by Kristiansen, 2007b) is categorized as a non-market-based method nonetheless because it is not only the market that determines prices and volumes, but the auctioneer who can use its initial pricing mechanism to allocate capacity.	
Advantages: Artificial pricing to achieve other goals can be applied	**Disadvantages:** Auctioneer can profit from creating an economically inefficient situation

Retention	
This scheme reserves the transmission capacity for vertically integrated utilities. (Kristiansen, 2007b)	
Advantages: Decreases investment risk for vertically integrated utilities Efficient investments in grid capacity (production plans are known internally)	**Disadvantages:** Discrimination of new entrants May lead to economically sub-optimal allocation

B.1.3 Redispatch using market-based criteria

The methods described in this section make use of some form of market-mechanism, but are categorized under 'Active TSO involvement' nevertheless because the TSO actively needs to trade power in order to solve these constraints. It is thus actively involved in monetary flows other than regular transmission tariffs. This is different from the methods described in section B.2, where the market solves congestion on its own and the TSO plays a facilitating role only.

Basic system redispatch	
Under this method generators in a constrained area are 'constrained off' on the basis of bids for this purpose and compensatory power ('constrained on' power) is acquired elsewhere (in a non-constrained zone) by the TSO. Despite being constrained off, constrained off producers are credited for their intended production. They can thus sell the same volume as originally contracted by their customers, but since their plants do not run they save their variable costs. They are thus willing to pay the TSO an amount up to these variable costs to be constrained off, as this makes them better off than producing. Congestion costs arise because the acquisition of constrained on power (by the TSO) is more expensive than the constrained off payment benefits. These costs, which are borne by the TSO under this scheme, can be (partly) transferred to customers and generators, thereby socializing them. See Hakvoort et al. (2009), sections 2.2.2 and 4.3.	
Advantages:	**Disadvantages:**

52 See footnote 50.

Cost allocation flexibility Low transaction costs	No incentives to locate outside congestion area Vulnerable to market power and gaming

Co-ordinated Re-dispatching Cost +

Charges for the use of a particular (cross-border) transmission line are set on the basis of the costs involved with redispatching plants in order to limit excessive imports/exports. See (Turvey, 2006), section 3.12.

Advantages:	**Disadvantages:**
Transmission charges reflect the cost of redispatching Costs are not targeted at consumers Incentive to create reverse flows (providing relief to congested lines)	

Counter trade

If transport demands for electricity traded between market payers are physically unfeasible, the TSO, acting as a single buyer, trades electricity in a way necessary to solve grid constraints. System redispatch, as described above, is actually a form of counter trading. The concept of counter trading, however, is more broad and the redispatch criteria and financial reimbursement schemes can vary. Also, the method is not limited to generation, but can also include the involvement of demand in order to solve congestion (involving demand is applied in the Nordic area, although participation is low (Glachant & Pignon, 2005)). The costs can be (partly) socialized among society through network tariffs. In brief, counter trading allows a market to be cleared as a whole despite transmission constraints. More information can be found in Bjørndal & Jörnsten (2007) section 2, or Glachant & Pignon (2005) section 3.

Advantages:	**Disadvantages:**
Low transaction costs	No incentives to locate outside congestion area

Hybrid redispatch

This method is a combination of market redispatch (with respect to constrained off power) and system redispatch (with respect to constrained on power). Generators in the congestion area place bids reflecting their lost profits if they would be constrained off, so if congestion arises the most expensive generators (i.e. those with the lowest lost profits) can be constrained off. Generators that are not constrained off pay the congestion price, which is set equal to the height of the highest accepted constrained off bid. Constrained off generators are still credited with the constrained off electricity, but are charged the current market price for compensating this power. Under the hybrid redispatch scheme this compensatory power is acquired by the TSO, which incurs a cost equal to the difference between above-marginal cost (of the compensatory power) and the market price (charged to constrained off generators as described above). This cost is compensated by the congestion costs charged to generators in the congestion area that are not constrained off. See Hakvoort et al. (2009), section 4.6, for more information on the hybrid redispatch scheme.

Advantages:	**Disadvantages:**
Cost of compensatory power will be (mostly) covered by congestion charges Incentive to locate outside congestion area No market power problems in constrained off market Short-term economic efficiency	No incentive for demand to locate inside congestion area Resistance from producers: those in congestion areas effectively receive a lower electricity price ('losers') than outside such areas ('winners') Vulnerable to market power in constrained on market

Market redispatch

Under this scheme generators need to contract compensatory power themselves if they are constrained off. In order to decide which generators are constrained off, all generators place bids that should reflect the cost of redispatching a plant themselves. If congestion occurs, the system operator calls off the lowest bids and these generators need to take care of redispatching compensatory power themselves (outside the constrained

area). The congestion price, which is set by height of the highest constrained off bid, needs to be paid by all generators that are **not** constrained off. More information on this method can be found in Hakvoort et al. (2009) section 4.5.

Advantages:	**Disadvantages:**
Generators are not compensated for congestion Incentive to locate outside congestion area Net revenues for system operator	High transaction costs Resistance from producers: those in congestion areas effectively receive a lower electricity price ('losers') than outside such areas ('winners')

System redispatch with cost pass-through to generators	
This method is similar to basic system redispatch, as described above, but differs in the way costs are allocated. Under this scheme congestion costs are borne by generators **within the constrained zone**, but **not constrained off**. This motivates generators to bid competitively and close to their true variable costs. For more information see Hakvoort et al. (2009), section 4.4.	
Advantages: Congestion costs for consumers cannot get out of control Incentive to participate in constraint market Low transaction costs	**Disadvantages:** No flexibility in cost allocation No incentives to locate outside congestion area Vulnerable to market power and gaming (though reduced in comparison with basic system redispatch)

B.2 Market coordination

This section discusses the congestion management methods that make use of differentiated transmission pricing (explicitly, B.2.1, or implicitly, B.2.2) to solve congestion.

B.2.1 Auctioning of transmission rights

Coordinated explicit auction	
Market players who want to import or export electricity need to acquire transmission rights corresponding to the volume of power that they want to transport. Rights for a specific volume to be transported over a specific period are auctioned by a single auctioneer and market players can bid into this market. For more information, please refer to (Brunekreeft et al., 2005) section 3 (p. 84).	
Advantages: Increased utilization compared to the decentralized version	**Disadvantages:** Higher transaction costs than implicit auctions

Flowgate rights system	
In theory, market participants need to acquire transmission rights on every single power line they need to use in order to carry out their desired market transactions. In practice, however, there is only a (much smaller) number of commercially significant lines (flowgates) (CSFs) for which rights need to be aquired. See e.g. Brunekreeft et al. (2005) and Pérez-Arriaga & Olmos (2005) (section 3).	
Advantages: CSF rights are easily tradable Transmission system usage is priced	**Disadvantages:** Higher transaction costs than implicit auctions Separate trading of rights for every CSF

Point-to-point rights system
Suppliers that wish to carry out market transactions that cross congestion region borders need to acquire point-to-point rights that cover their desired transaction pattern. See (Pérez-Arriaga & Olmos, 2005) (section 3).

Advantages:	**Disadvantages:**
No need to acquire separate rights for every individual line Transmission system usage is priced	Higher transaction costs than implicit auctions Not as easy to trade between market players as CSFs

B.2.2 Price differentiation (to geographic area)

APX-based method	
The key characteristic of this method is that geographical cost differentiation is applied, but uniform pricing is maintained. All producers are required to offer their production into a central spot market, regardless of other supply obligations. Effectively they place a bid for transmission capacity. Depending on the feasibility of the market transaction pattern, some initially accepted offers may be rejected (does not apply to renewable sources, insofar these are below MCP) and rejected offers (above market clearing price) are accepted to cover the loss in production. The latter are paid a price equal to their offer, whereas the former receive no compensation whatsoever. Accepted offers which lie within a constrained zone (that is, one or more offers from their zone were rejected due to transmission constraints) receive a price below market clearing price according to a predefined procedure (renewable sources always receive MCP). The difference should cover the expense of compensating the above-MCP offers that were accepted due to transmission constraints. More information can be found in TenneT (2009d).	
Advantages: Uniform pricing is maintained Incentives for capacity expansion are maintained	**Disadvantages:** Provides no locational incentives for demand

Market splitting	
Under market splitting a market is divided in two or more nodes, but it is in principle cleared as one single market with a uniform price. If the transaction pattern as desired by market players cannot be physically implemented, the market is split into two or more nodes with price differences corresponding to the shortage in transmission capacity. See e.g. Ehrenmann & Smeers (2005), Kristiansen (2007a), and Pignon (2002).	
Advantages: Economically efficient Increased liquidity (compared to nodal pricing) Locational incentives are provided	**Disadvantages:** No incentive for TSO to expand capacity

Nodal pricing	
By dividing an electricity market in a number of nodes of which the borders are chosen as such that no congestion occurs internally within these nodes but only between them, price differences among the nodes that reflect transmission constraints ensure that market transaction patterns are technically feasible. In theory it is often considered to be the economically most efficient congestion management method that provides the right incentives to make efficient use of the transmission system, but since it does not provide incentives for the TSO to expand capacity this may not always be valid. See Brunekreeft et al. (2005) (section 3).	
Advantages: Economically efficient Locational incentives are provided	**Disadvantages:** May result in illiquid markets No incentive for TSO to expand capacity

Zonal pricing
Similar to nodal pricing, in the sense that different nodes that are identified are grouped into zones (which are then considered as single nodes). The exception is that there are no price differences between nodes that are grouped into the same zone, which implies that arising transmission constraints need to be dealt with in a different manner. Zonal pricing can be applied using permanent or variable zones. In the latter situation

the grouping of nodes into zones is subject to (semi-)continuous change, which is for instance applied in Norway (Johnsen et al., 1999). Defining zones is done on the basis of priorly determined factors or at discretion of the responsible authorities. More information can be found in Bjørndal & Jörnsten (2007), Johnsen et al. (1999) and Leuthold et al. (2008).	
Advantages: Allows for partial application of uniform pricing Improve market liquidity in case of a small number of market players	**Disadvantages:** Need to apply other CM-methods within zones Transaction costs for defining zones

B.3 Demand-side measures

The methods described in section B.1 were aimed at producers, whereas the methods in section B.2 make use of both producer and consumer reactions[53] to solve congestion. This section discusses two methods that can help alleviate congestion by creating a consumer response, rather than solving congestion from a production perspective.

B.3.1 Congestion solved by consumer reaction to situation

Demand-side bidding	
This scheme is discussed by Johnsen et al. (1999) which defines demand-side bidding as a mechanism where certain consumers commit to reducing their demand when prices rise. This scheme could, of course, also be applied on the basis of other criteria (such as the congested volume) with participants in the scheme being reimbursed according to a pre-determined scheme.	
Advantages: Economic efficiency, with customers placing a low value on electricity being cut off temporarily	**Disadvantages:** Requires sufficient participation Provides no solution if congestion exceeds participating volume

Transmission loading relief	
If transactions carried out by market players cause congestion, all demand that contributes for more than 5% to this congestion is cut.	
Advantages: Simple procedure	**Disadvantages:** Economically inefficient

53 Except for the APX-based method, under which uniform pricing is maintained.

Appendix C: Simulation model construction

For answering the research question (in particular sub-questions 3 and 4) a simulation model is needed that allows to calculate outcomes on factors of interest – region congestion sensitivity, opportunities to exert market power, congestion costs and their distribution – under different scenarios. This appendix will describe how this model was created. It elaborates on the simulation objectives and resulting choice of modeling technique (C.1) and discusses the model specification process (C.2). Note that data requirements (and the processing thereof) and verification and validation (model testing) are discussed in Appendices D.1 and D.2 respectively. The simulation results obtained by running the model for different congestion management methods under various scenarios are presented in Appendix H.

C.1 Modeling technique

To obtain meaningful simulation results it is important that the choice of modeling technique and simulation tools is consistent with the modeling objectives. The objectives of the simulation exercise are to find out whether (and, if so, how much and where) congestion occurs under particular circumstances, in order to calculate the resulting costs, incentives, and potential for abuse if such a situation were to happen in reality. The model will thus not calculate these outcomes on a continuous scale for a particular period (e.g. 2011–2020) but aims to determine the outcomes of a particular scenario if it were to occur.

What the model basically needs to do is calculate the network flows that result if market players desire to carry out a particular transaction pattern. This transaction pattern is thus used as input for the model and forms a part of the scenarios that were constructed (for the construction of these scenarios, see Appendix G). The model essentially needs to perform three distinct functions:

1. Calculate market outcomes (i.e. determine demand and supply obligations)
2. Determine dispatch (using supply obligations)
3. Calculate resulting network flows (using demand and dispatch information)

If necessary, an iteration is made from step 3 to step 1. This could, for instance, be required when simulating market splitting when the transmission flows under a uniform price situation cannot be physically implemented and the market needs to be cleared with two or more sub-markets. The functions mentioned above are modeled as three separate sub-systems, which is graphically represented in Figure 11 and will be elaborated in section C.2.

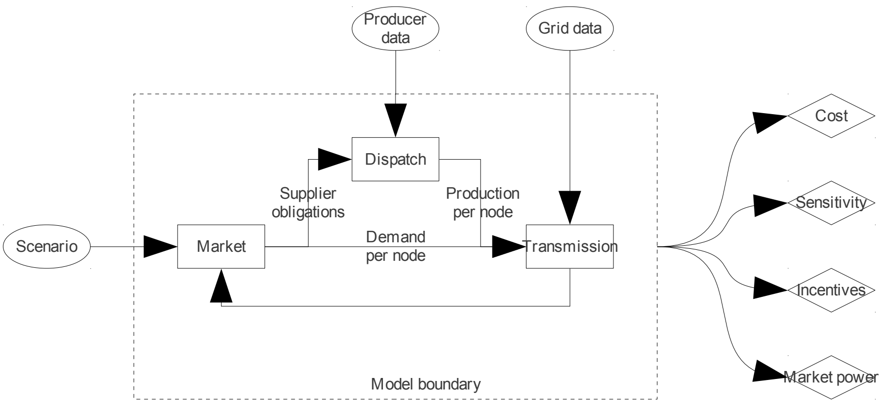


Figure 11: Conceptual representation of system

The static nature of the model allows for its implementation in a spreadsheet application. More specifically, this model was implemented using the office suite applications *OpenOffice Spreadsheet* and *Microsoft Excel*. Interoperability between both applications was achieved by using a file format that could be used under both applications. Using their 'solver' functions it is possible to optimize values within the model under constraints, a function which is used in the *Dispatch* and *Transmission* sub-models. How this was done for these sub-models is further discussed in sections C.2.2 and C.2.3.

C.2 Specification

This section describes how the model was created based upon the conceptual representation of the system as introduced in Figure 11. It will first provide an "overall description" and then discuss the three sub-models (Market, Dispatch, and Transmission) separately.

Figure 11 already indicated how sub-model outcomes are used as input in other sub-models. Although the details of this will become clear in sections C.2.1 to C.2.3, it is important to note that one key function of the model is its ability to link producers, production units, capacities, and congestion regions to each other in various ways. On various occasions the model needs to group this data in different manners (e.g. production units under either producers or congestion regions) in order to perform calculations. To this extent the simulation model contains a spreadsheet overview of all production units with the respective information, the values of which can be looked up by model elements whenever necessary. A complete overview of the data in this overview is provided in section D.1.1.

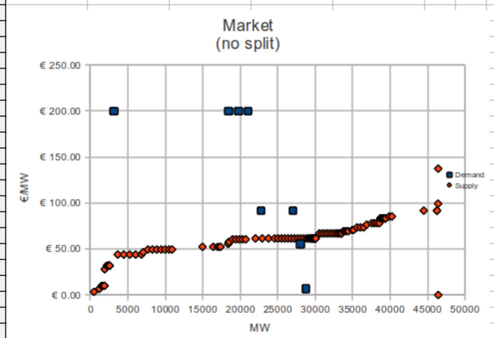
For instance, the *Dispatch* sub-model determines the dispatched production units by looking up their respective owner – which holds the supply obligation – in this overview, and dispatches plants accordingly. Similarly, the *Transmission* sub-system aggregates the production of all generating units to a single production figure for one node by calculating the sum of all dispatched capacity whose congestion region value matches with the region that is aggregated for.

C.2.1 Market sub-system

The process that takes place in electricity markets determines the production and consumption obligations. Because every bid is connected to a location, it is possible to calculate (aggregated) demand per node. This information is required for the *Transmission* sub-model, because together with dispatch (per node) it determines the resulting network flows. The *Market* data on supplier obligations is used in the *Dispatch* sub-model to determine the dispatch of production units.

	A	B	C	D	E	F	G
1	SCENARIO	1		Basic System Redispatch			
2							
3		Demand					
4	Node	Volume (cum	Bid	Accepted?	Surplus		
5		MW	€/MW				
6		0					
7	1	3097.695949	€ 200.00	3097.695949	€ 428,964.18	C	NL
8	2	18460.98633	€ 200.00	15363.29038	€ 2,127,484.89	C	NL
9	3	19750.99374	€ 200.00	1290.00741	€ 178,638.25	NC	NL
10	4	21037.94538	€ 200.00	1286.951635	€ 178,215.09	C	NL
11	6	22787.94538	€ 91.80	1750	€ 52,980.36	0	FOR
12	5	27037.94538	€ 91.80	4250	€ 128,666.59	0	FOR
13	8	28037.94538	€ 55.48	0	€ 0.00	0	FOR
14	7	28737.94538	€ 6.60	0	€ 0.00	0	FOR
38	Intersection		27037.94538	€ 61.52			

	I	J	K	L	M	N	O	P
3			Supply					
4	Supplier	Node	Volume (cum	Offer	Accepted?	Revenue	Surplus	
5			MW	€/MW				
6			0.0					
7	Producer A	4	480.0	€ 3.43	480.0	€ 29,530.34	€ 27,881.99	C
8	Producer D	7	1180.0	€ 6.60	700.0	€ 43,065.07	€ 38,445.07	0
9	Producer B	2	1499.9	€ 10.00	319.9	€ 19,680.44	€ 16,481.49	C
10	Producer A	4	1646.3	€ 10.00	146.4	€ 9,005.15	€ 7,541.41	C
11	Producer B	1	1766.3	€ 10.00	120.0	€ 7,382.19	€ 6,182.26	C
12	Producer A	3	1828.1	€ 10.00	61.8	€ 3,802.03	€ 3,184.03	NC
13	Producer A	2	1852.1	€ 10.00	24.0	€ 1,476.52	€ 1,236.52	C
14	Producer B	2	1873.7	€ 10.00	21.6	€ 1,328.87	€ 1,112.87	C
15	Producer A	4	1908.1	€ 27.97	34.4	€ 2,116.34	€ 1,154.23	C
16	Producer C	2	2185.2	€ 31.90	277.1	€ 17,047.62	€ 8,206.84	C
17	Producer A	1	2346.2	€ 31.90	161.0	€ 9,904.97	€ 4,768.32	C
18	Producer A	3	2411.2	€ 31.90	65.0	€ 3,998.90	€ 1,925.10	NC
19	Producer C	3	2471.2	€ 31.90	60.0	€ 3,691.29	€ 1,777.01	NC
20	Producer D	3	2516.2	€ 31.90	45.0	€ 2,768.47	€ 1,332.76	NC
21	Producer D	4	2548.2	€ 31.90	32.0	€ 1,968.69	€ 947.74	C
22	Producer C	2	2578.2	€ 31.90	30.0	€ 1,845.65	€ 888.51	C
23	Producer A	2	2603.2	€ 31.90	25.0	€ 1,538.04	€ 740.42	C
24	Producer D	3	3653.2	€ 44.00	1050.0	€ 64,597.61	€ 18,393.41	NC
25	Producer A	3	4453.2	€ 44.00	800.0	€ 49,217.23	€ 14,014.02	NC
26	Producer A	4	5253.2	€ 44.00	800.0	€ 49,217.23	€ 14,014.02	C
27	Producer A	1	6033.2	€ 44.00	780.0	€ 47,986.80	€ 13,663.67	C
28	Producer B	1	6813.2	€ 44.00	780.0	€ 47,986.80	€ 13,663.67	C
29	Producer D	2	7048.2	€ 46.55	235.0	€ 14,457.56	€ 3,518.12	C
30	Producer A	2	7678.2	€ 49.48	630.0	€ 38,758.57	€ 7,586.42	C
31	Producer C	2	8278.2	€ 49.48	600.0	€ 36,912.92	€ 7,225.16	C
32	Producer A	2	8871.2	€ 49.48	593.0	€ 36,482.27	€ 7,140.86	C
33	Producer A	2	9451.2	€ 49.48	580.0	€ 35,682.49	€ 6,984.32	C
34	Producer D	3	9976.2	€ 49.48	525.0	€ 32,298.81	€ 6,322.01	NC
35	Producer A	3	10501.2	€ 49.48	525.0	€ 32,298.81	€ 6,322.01	NC
36	Producer A	4	10907.2	€ 49.48	406.0	€ 24,977.74	€ 4,889.02	C
37	Producer A	2	14964.2	€ 52.44	4057.0	€ 249,592.86	€ 36,848.38	C
38	Producer B	3	16399.2	€ 52.44	1435.0	€ 88,283.40	€ 13,033.63	NC
39	Producer C	1	17002.2	€ 52.44	603.0	€ 37,097.48	€ 5,476.85	C
40	Producer C	4	17268.2	€ 52.44	266.0	€ 16,364.73	€ 2,415.99	C
41	Producer C	2	17360.3	€ 52.44	92.1	€ 5,666.13	€ 836.51	C
42	Producer D	3	17385.3	€ 52.44	25.0	€ 1,538.04	€ 227.07	NC
43	Producer A	8	18385.3	€ 55.48	1000.0	€ 61,521.53	€ 6,044.84	0
44	Producer D	1	18469.3	€ 57.73	84.0	€ 5,167.81	€ 318.11	C
45	Producer A	2	18529.3	€ 57.73	60.0	€ 3,691.29	€ 227.22	C
46	Producer A	2	18979.3	€ 60.55	450.0	€ 27,684.69	€ 438.72	C
47	Producer A	2	19429.3	€ 60.55	450.0	€ 27,684.69	€ 438.72	C
48	Producer C	2	19879.3	€ 60.55	450.0	€ 27,684.69	€ 438.72	C
49	Producer A	3	20304.3	€ 60.55	425.0	€ 26,146.65	€ 414.35	NC
50	Producer B	3	20729.3	€ 60.55	425.0	€ 26,146.65	€ 414.35	NC
51	Producer D	2	22029.3	€ 61.52	1300.0	€ 79,977.99	€ 0.00	C



1 Mkt / 2 Dptch / 3 Flw / Cong / 4 Cstr pw / 5 Dptch / C Calc / KPIs / (Load) / (MCst) / (DG) / (Prod) / (NodC) / (UtH)

Figure 12: Screenshot of Market sub-model (anonymous offers)

Although the implementation of this sub-model is slightly different for each of the congestion management methods that were simulated, the outcome is conceptually similar for each: an overview of the demand (which can be aggregated as total demand per node, as the location of each bid is known) and supply obligations.

Determining market price and volume

The model makes use of a simulated spot market to auction power and/or transmission capacity. Ideally, it would contain a table with all bids (demand) and offers (supply). This table would then show all volume/price-pairs for demand and supply, including information on the respective customer/supplier, their location, asked/offered volume, and bid/offer price for each entry.

Unfortunately, insufficient data was available to construct sufficiently realistic volume-price bid pairs, so demand was included as a linear function. Thus, only the supply-side is modeled in the manner described above, including individual volume/price-pairs for supply offers based upon production capacity and their marginal costs. Please refer to appendices D.1.1 and D.1.2 for more information on the quantitative model implementation of supply and demand respectively.

Because neither OpenOffice.org Spreadsheet nor Microsoft Excel are able to calculate the resulting intersection – which is the marginally accepted volume/price-pair that sets the market price and volume – a graph of this information is created in order to to manually determine the intersection point. The corresponding values for volume and price are subsequently manually entered (Figure 12) in order for the model to calculate which bids and offers are accepted.

Marginal cost curve

Market transaction patterns can be (and generally are) completely different from physical electricity flows. Within the constraints set by the laws governing the physical behavior of electricity, electrical power simply flows from generation facilities where it is produced to load centers where it is consumed. In the market, however, everyone is free to trade electricity – including parties that neither own any generation facilities nor have any functional use for the power they trade – and traders may have a variety of reasons to place offers and bids. Electricity can be offered by a producer having no other supply obligations based on its true variable costs, but customers can also decide to sell their already contracted power if the market price is sufficiently high.

In an efficient market the cheapest plants available will thus be dispatched first. For instance, if a producer owns production capacity and is engaged in long-term bilateral contract, they may decide to buy the power they are obliged to supply on the spot market rather than produce itself if this price is below its own marginal cost level. If it is not, the party on the purchasing side could sell the power they contracted at a lower price to the market at a profit, if this profit exceeds the economic value the electricity itself has for them.

The marginal costs that were assumed in the model can be found in Appendix D.1.2. Note that this refers to the base case scenario; some scenarios may assume different costs which is discussed in the section dealing with the respective scenario (see Appendix G).

C.2.2 Dispatch sub-system

This sub-model calculates the dispatch of production units, in order to determine the aggregated production per node. This information is required in the *Transmission* sub-model in order to calculate the network flows. Although this is a very straightforward aspect for small producers with units in only one congestion region, many producers have generating units in different congestion areas, and it is thus not possible to determine network flows solely on the basis of supply obligations.

The *Market* sub-model provides an overview of the supply obligations for each producer. Linear programming is used to calculate the most efficient dispatch possible, given the supply obligations of each supplier (used as constraints when solving the optimization problem). The model assumes that producers will dispatch their cheapest plants first and an optimization algorithm that calculates the least-cost dispatch. This is shown in Figure 13. The optimization algorithm seeks to minimize these dispatch costs for every producer by dispatching generating units with a low merit order value first. This results in an overview that shows which production units are (partly) dispatched. The *Transmission* sub-model uses this information to calculate total production in a particular node, which is possible because the congestion region is defined for each generating unit.

Supply obligations

Supplier	Offered	Supplied
Producer A	2000	=SUMIF($F$3:$F$14,A3,$J$3:$J$14)
Producer B	1000	1000
Producer C	3000	3000
Producer D	2000	2000

Unit	Owner	Location	Available capacity	Variable cost	Dispatched	"Cost"
A1	Producer A	1	1000	€ 5.00	1000	=I3*J3
A2	Producer A	2	500	€ 1.00	500	€ 500.00
A3	Producer A	1	500	€ 8.00	500	€ 4,000.00
B1	Producer B	3	400	€ 2.00	400	€ 800.00
B2	Producer B	2	500	€ 4.00	500	€ 2,000.00
B3	Producer B	4	300	€ 9.00	100	€ 900.00
C1	Producer C	2	1500	€ 2.00	1500	€ 3,000.00
C2	Producer C	4	1000	€ 6.00	500	€ 3,000.00
C3	Producer C	1	1000	€ 1.00	1000	€ 1,000.00
D1	Producer D	2	800	€ 4.00	800	€ 3,200.00
D2	Producer D	2	600	€ 6.00	200	€ 1,200.00
D3	Producer D	3	1000	€ 4.00	1000	€ 4,000.00

Total cost (MINIMIZE) € 28,600.00

Figure 13: Sub-model Dispatch (optimization sheet) (note: this figure shows a simplified example)

C.2.3 Transmission sub-system

Because a congestion region value is attached to every generating unit, the total production per node can be obtained on the basis of the dispatch overview mentioned above. Distracting the production within a particular node from its consumption (which was already obtained in the *Market* sub-model, see above) results in the net demand that must be met by imports[54] from another node. A negative net demand is considered as export. As the *Market* sub-model always results in equal consumption and production obligations, the sum of all net demands in the *Transmission* sub-model should be exactly 0 (reflecting reality). The model contains a verifying mechanism that notifies the user if this is not the case, which indicates an error.

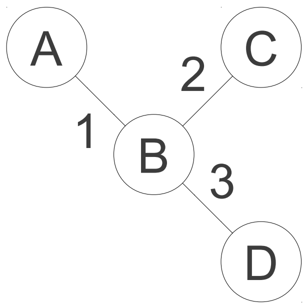


Figure 14: Example: assume minimum flow problem

The first step in calculating the flows resulting from a given set of net demands is to determine the total power that needs to be transported between the nodes. With the exception for the interconnections with Germany and Belgium (which are connected to two Dutch nodes each) the network is assumed not to be meshed, which effectively allows the problem to be solved as if it were a minimum flow optimization exercise. The net demand of each node must be met, thereby obeying Kirchhoff's current law, while physical power flows will be such that the resistance that is encountered is as small as possible. This can be illustrated by a four-node example as shown in Figure 14. If node A has a net supply of 100 MW and node D has a net demand of 100 MW, while production and consumption in nodes B and C being equal and their net demand thus 0 MW, one can easily comprehend that the flow in lines A-B and B-D will be 100 MW, whereas the flow in line B-C should be 0 MW because the voltage drop equals zero.

Although somewhat more extensive than this example, the model (8 nodes and 15 connections) is constructed using the same principle. The only two exceptions to this rule are the interconnections with Germany and Belgium, because these create a meshed network due to their connections with two nodes within the Netherlands (see Figure 3 in section 4.2.1). In order to correctly model the power flows to, from, and across these nodes, a set of power transfer distribution factors (PTDFs) was calculated that allows for the incorporation of different paths that are taken by power flows in reality. These PTDF calculations can be found in Appendix D.3.

54 Note that electricity flows from one node to another is considered import (or export) in the model, irrespective of whether flows cross *national* borders.

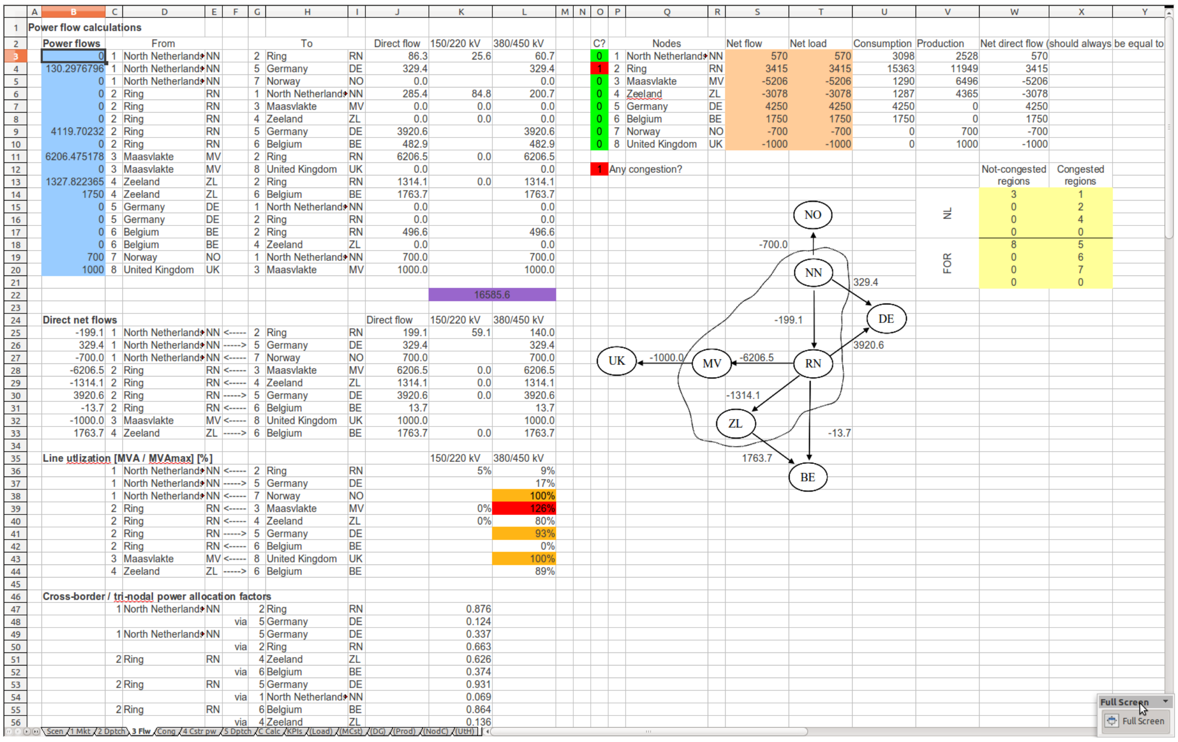


Figure 15: Screenshot of Transmission sub-model

C.2.4 Congestion: an iteration

If congestion arises on the basis of the scheduled flows calculated in the *Transmission* sub-model, an iteration is made in which market offers are adjusted according to the rules that apply under the congestion management method applied. Note that the spreadsheets used to simulate the initial *Market*, *Dispatch*, and *Transmission* sub-models are not 're-used', because the market process and dispatch rules slightly differ from the initial situation assuming no congestion. In that sense the model is not truly used in an iterative manner as was presented by Figure 11. However, the concept is iterative: in second instance the *Market*, *Dispatch*, and *Transmission* model-components are run again. Also note that this is important in order to allow for a comparison between the quantitative outcomes under the assuming-no-congestion models and the congestion management models.

Basic system redispatch

Generators in the area upstream of congestion (excluding renewable energy) place *constrained off* bids and those in the area downstream of congestion place *constrained on* offers, all reflecting marginal costs. The accepted bids and offers are subtracted from and added to the generators initially accepted capacities in the respective congestion zones. When the Dispatch sub-model is run again for the congested situation, it takes these new or altered production obligations into account, rather than the initial accepted offers.

Market splitting

Under market splitting the generators' bids are divided in two groups and cleared as if there were two separate markets. An additional offer is placed in the high-price area market, which has a volume equal to the maximum ATC between the two zones and is supplied at a price level of 0, so it is always accepted. The low-price area has an additional demand of equal volume, which is also always accepted (price level: ∞).

APX-based method

The APX-based method works in a fashion similar to BSR, with the exception that the *constrained* *off* bids and *constrained on* offers are by definition equal to initial market offers. There is thus no separate bidding process.

Market coupling

Under market coupling the *Transmission* and *Market (under congestion)* sub-models are integrated. On the basis of the supply offers in the four nodes (plus four foreign nodes) and the available transfer capacities between them, the algorithm seeks to maximize social welfare by finding the optimum flow pattern. This is conceptually explained in section 4.4.3.

C.3 Using the model

One of the disadvantages of the simulation model that was constructed is that it requires some manual steps while running it. This section will specify what steps running the model consists of.

C.3.1 Market

The objective of the *Market* sub-model is to determine the MCP and volume traded, on the basis of many generator bids and (fixed) demand. Figure 12 shows all the individual offers, which is the result of this first simulation step. Each producer is assumed to offer the capacities of its units to the market at marginal cost. The model *Market* sub-model thus needs data on the volume and variable cost for each separate unit, as well as information on its owner because this determines the total supplied capacity for each producer. In addition, an indication of the congestion region is attached to each offer. Although this has no influence at this stage, because the market is cleared assuming no congestion, it is required to be able to determine congestion costs for different congestion zones when the simulation is run.

> ***Exception:***
> *Under the market coupling method the offers are inserted in four different tables, each of which containing the offers for one specific node.*

All required information is available in the '(Prod)'-tab of the spreadsheet, and the contents of the relevant columns (Producer, Congestion region, Capacity, Marginal cost) are copied to the 'Scenario'-tab, which is the tab where all input variables are located. One must manually sort the offers by their price level, in ascending order, so the cheapest generators can be found at the top. The *Market* sub-model, or the '1 Mkt'-tab, contains references to the offer tables in the 'Scenario'-tab and automatically includes all changes made there. Using these offers it shows a supply curve in a graph, which also shows the load in the Netherlands (at a price level such that is always accepted) and foreign demand (at price levels that reflect the MCP assumed in that country; see Appendix D.1.1). This graph is inserted mainly for the purpose of convenience, because the model user must manually enter the intersection of the demand and supply curves. When this is done, the model will automatically calculate the offers that are accepted, as well as those that are rejected.

C.3.2 Dispatch

The *Dispatch* sub-model, shown in Figure 13, consists of an overview of all producers and the sum of their offers (in terms of volume) accepted in the *Market* sub-model, and an overview of all production units with data on their owner, congestion region, maximum capacity, variable cost, capacity currently dispatched, and cost of dispatch (capacity currently dispatched multiplied by the variable cost). The user of the model must run the OpenOffice.org or Excel *Solver* functionality, where they specify that the algorithm must seek to minimize total actual cost of dispatch by altering the *capacity currently dispatched*, under the

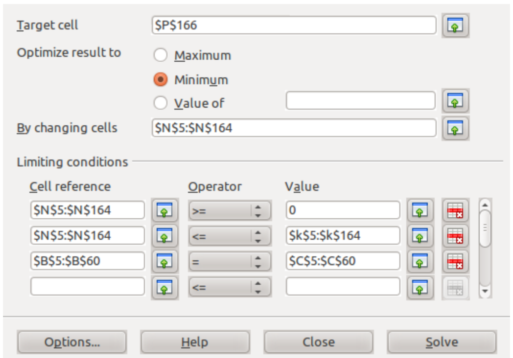


Figure 16: Solver settings for Dispatch sub-model

constraints that:

- "Capacity currently dispatched" is larger than or equal to 0,
- "Capacity currently dispatched" is smaller than or equal to "maximum capacity",
- "Sum of accepted offers" is equal to "Capacity currently dispatched"

This is also shown in Figure 13. Solver will return the volumes that generators must dispatch in order to fulfill their supply obligations in the cheapest manner possible.

C.3.3 Transmission

Given the accepted demand in the different nodes (which equals the load) and the capacities that generators dispatch in the different locations (determined in the '2 Dptch'-tab), the *Transmission* sub-model ('3 Flw'-tab) will determine the transmission flows that are created by the dispatch and load patterns. Because the network is assumed to be only slightly meshed this step can also be performed by an optimization algorithm, as was discussed in Appendix C.2.3. The user must specify its settings such that the objective of Solver is to find the minimum flows required, under the constraints that:

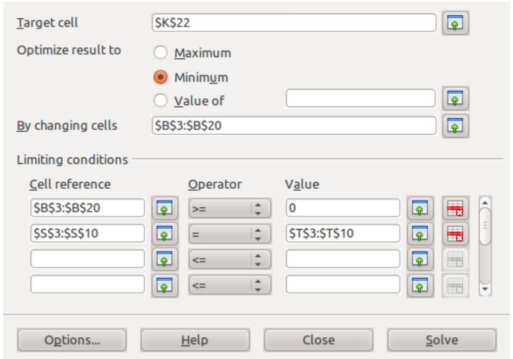


Figure 17: Solver settings for Transmission sub-model

- All flows are equal to or large than 0 MVA,
- Net flow (calculated on the basis of flows) equals Net load (calculated on the basis of consumption minus production), in each node.

This will lead Solver to converge to the flow pattern that is necessary to transport power from nodes with a net surplus to nodes with a net deficit, with the sum of production, consumption, imports, and exports to be zero in each node.

As a last step, the model user must specify which nodes are in the not-congested (upstream) zone, and which are in the congested (downstream) zone. This can be done in the yellow area shown in Figure 15.

C.3.4 Congestion

Under congestion another *Market* algorithm must be performed, which is different for all congestion management methods and these will therefore be discussed below. The *Dispatch* and *Transmission* sub-models function similar to those described above, with the exception that under the *Dispatch* sub-model a distinction is made between the production in the area upstream of congestion and the area downstream of congestion. As a result, the producer offer totals must now be met by dispatching capacity in one of the areas specifically, which leads to a slightly different Solver constraint:

- "Sum of accepted offers" is equal to "Capacity currently dispatched"

must now become:

- "Sum of accepted offers in C-area" is equal to "Capacity currently dispatched in C-area"
- "Sum of accepted offers in NC-area" is equal to "Capacity currently dispatched in NC-area"

Both the other constraints can remain unchanged.

Basic system redispatch

The basic system redispatch mechanism requires that the capacity is calculated which needs to be redispatched from one area to the other. This is done in the tab 'Cong', which is actually a variant of the *Transmission* sub-model but slightly adapted for its purpose to calculate the congested volume.

Using Solver the user can calculate the minimum required volume of redispatch to solve congestion (the objective is to find the minimum required volume, because any deviation will result in a less than optimal dispatch pattern and therefore one aims to keep the deviation as small as possible – for more information on this, please refer to section 4.4.3). For this purpose solver needs to be run with the following constraints:

- All flows are equal to or larger than 0 MVA,
- Actual flows do not exceed grid capacities,
- Net flow (calculated on the basis of flows) equals Net load (calculated on the basis of consumption minus production), in each node.

This returns the minimum volume that needs to be *constrained off* in the not-congested area and needs to be *constrained on* in the congested area.

Market splitting

Applying market splitting results in the creation of two (or more) separate spot markets, between which a volume is traded that maximizes the use of the available transmission capacity. After determining the total flows in the *Transmission* sub-model, the market splitting algorithm will determine which congestion zones need to be identified in order to calculate the maximum available transmission capacities (ATC) between these zones. The model is unable to calculate this ATC automatically, so this must be done by the user as follows:

1. Identify the bottleneck (which can be obtained from the *Transmission* sub-model, as the connection that, proportionally to its capacity, experiences the most heavy load)
2. Divide this figure by its two-nodal PTDF (this determines the total ATC using both the 220 kV and the 380 kV networks)
3. In case of a meshed network, divide this figure by its tri-nodal PTDF (in order to obtain the total ATC over a zonal border which divides multiple nodes in two groups)

The value that is obtained is expressed in MW[55] and can subsequently be provided to the congestion market sub-model. Using this value as a price-independent offer (see section 4.4.3), a new set of accepted offers for all regions, taking into account the power that can be transported among them.

Note that the manual ATC calculations are practical only because the model is not heavily meshed. Meshing occurs simultaneously for no more than three nodes (and connections). In case of a more heavily meshed network, however, it is strongly advised to invest in a model that is able to perform the required ATC calculations automatically.

Market coupling

The simulation of market coupling is different from the other methods in the sense that there is no such thing as scheduled flows exceeding available transmission capacity, because the transmission flows between nodes are determined taking into account the constraints. The market coupling congestion management can be simulated by the user by running the Solver and letting it seek to maximize social welfare (see Appendix C.2.4) by changing the flows between the nodes. The following constraints must be manually added to Solver:

- Flows are equal to or greater than 0,
- “Actual flows” are equal to or smaller than “Maximum line capacities”,
- “Allowed?” = 1,
- “Actual flow [to/from DE and BE]” is equal to or smaller than “Commercially available capacity [to/from DE and BE]”

Solver will now try to calculate a social optimum (which is discussed in section 4.4.3) and

55 Note that this study only considers real power and neglects network losses. Therefore, the required transport of 1 MW is assumed to create a flow of 1 MVA.

determine the flows that accompany such an optimum. It is important to point out that neither OpenOffice Calc, nor Microsoft Excel were able to find this optimum in all instances in practice. This appears to be because the solution space contains multiple optima and Solver is unable to find the single, most optimal point in the solution space. The user may therefore need to run Solver multiple times, while adjusting the flows manually on the basis of expected improvements in between runs.

This situation can be visualized by Figure 18. If the Solver algorithm finds, for instance, the blue peak, it will not be able to also find the green peak without being manually positioned somewhere on the slope of the green "hill". (Note: this illustration is only supplied for explanatory purposes and does not visualize this specific problem).

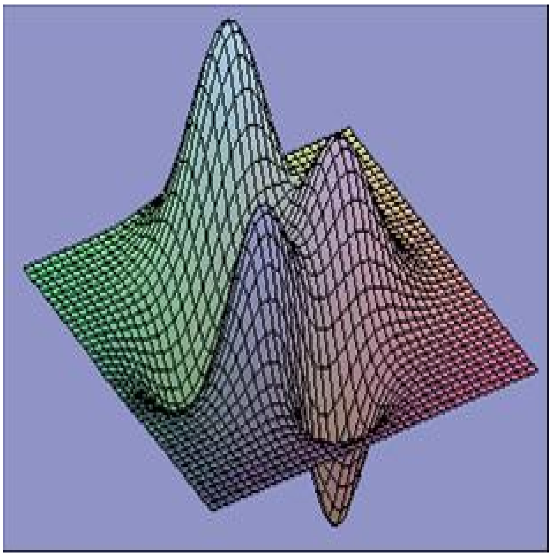


Figure 18: Visualization of a multiple optima problem (source: Rustem, 2011)

The problem is caused by the constraint that states that no power flows may exist from high-price areas to low-price areas. This limits the solver in its optimum-finding ability, because it cannot iterate to a different solution that meets this constraint but violates it during some of the iterations. To illustrate: for instance, if the previous iteration leaves the solution somewhere on the red hill in Figure 18, and the solver finds another solution that is on the slope of the green hill but violates the constraint, it will refuse to move to this point and see if it can go up the green hill where there is a solution that does not violate the constraint. Instead, Solver will always stay within the limits posed by this constraint (i.e. the red hill) and will therefore only be able to find the local optimum, rather than the overall optimum. This problem was not resolved because the time available was too limited.

APX-based method

Under the APX-based method the required redispatch volume is obtained using the same algorithm as basic system redispatch (see above).

C.3.5 Additional non-model spreadsheet tabs

Apart from three tabs for the sub-models described before (plus three additional tabs for each congestion iteration that is required), the spreadsheet document in which the model is constructed includes the following elements:

- Input factors (the "Scenario"-tab, in which the conditions for a specific scenario can be entered),
- KPI calculations,
- Data on loads,
- Marginal cost calculations,
- Data on distributed generation,
- Overview of centralized generation units,
- Nodal connections (PTDF calculations),
- "Under the Hood" (UtH) tab (which indicates possible errors in the model. The UtH tab is particularly useful because the model requires some manual steps to be performed.)

Appendix D: Data

This appendix provides an overview of the data that was required to use the model to simulate reality. Also, it will elaborate on its transformation whenever required. Most of this data was supplied by TenneT, either as raw data or by personal communication with experts in the field. All (other) data sources are explicitly mentioned when discussing a particular topic.

D.1 Market data

Two types of data are used as input in the *Market* sub-model, as was discussed in Appendix C.2.1: an overview of customer bids (forming a demand curve) and an overview of supplier offers (forming a supply curve).

D.1.1 Marginal cost of supply

Appendix C.2.1 discussed how the cheapest plants available would eventually run under a well-functioning market, regardless of the long-term bilateral supply contracts held by producers owning relatively expensive plants, which are out-of-merit under optimal dispatch at a given moment. This assumption of a well-functioning spot market that eventually allows for dispatch of the cheapest plants is interpreted by the model by simulating that every producer submits bids that reflect their variable cost of production, as they would under perfect competition. This perfect competition assumption may appear to be inconsistent with one of the main reasons for doing this study in the first place, which is evaluating situations where this is not the case. Note, however, that the objective of this study regarding market power is to identify the possibilities for strategic behavior to be exercised, i.e. from a societal perspective: the risk. It does not analyze the behavior of individual producers and the drivers for such behavior in detail, and thus allows the assumption of perfect competition to be kept in this element of the model.

The variable costs of power plants are assumed to be made up from two components:

- Fuel costs
- Emission rights costs
- Operational costs[56]

These costs are only created if the plant actually runs and they are assumed to be linear with the rate of production. In reality this linearity assumption is not entirely valid, for instance due to the existence of start up costs. Electricity production of coal fired and nuclear power plants cannot be increased as easily as, for instance, a gas turbine. It may take several hours to adjust the rate of production, which may cause producers to temporarily produce at a marginal loss rather than shutting the entire plant down. Marginal costs, and thus market offers, can then be lower than the cost of the above-mentioned components, at least for a particular share of production capacity.

Because it is practically impossible to take into account this effect, which depends on a variety of factors such as technical plant characteristics, expected shut down time (i.e. if a producer expects it will not be able to sell electricity against a price above marginal costs for a week it would shut down the plant, but if it expects this situation to last for only an hour, it may continue producing), and type of fuel contract, the model will assume that marginal costs are determined solely by the three cost components listed above. Note that the existence of this non-linear marginal cost effect may not even influence the outcomes of a static model as used in this study that much, as the market clearing price is set by the highest accepted marginal offer anyway. In a situation where all offered capacity was accepted it would thus not matter if a part of production capacity was offered at a lower price as a result of its must-run characteristics.

Please refer to Appendix D.2 for the data on the individual production units, which was necessary to calculate the costs in this section.

56 Note that operational costs have – at least in the short term – both a fixed (e.g. labor) and a variable (e.g. maintenance) component. Here, operational costs refer only to the truly variable elements of operational costs.

Fuel cost

In order to calculate the fuel cost of a particular plant, one needs to know its type of fuel and efficiency. For some plants thermal efficiency figures were provided by TenneT, but for others these were estimated on the basis of the type of plant (see Table 20).

Type of plant	**Assumed thermal efficiency (if not provided)**	**Source**
Brown coal (lignite)	40 %	(Sharma, 2007)
Hard coal (new)	45 %	(TenneT, 2009e)
Hard coal (old)	35 %	(TenneT, 2009e)
Hydro	100 %	(Sharma, 2007)
Natural gas (CHP)	45 %	(Sharma, 2007)
Natural gas (combined cycle)	58 %	(Sharma, 2007)
Natural gas (gas or steam turbine)	38 %	(Sharma, 2007)
Nuclear	37 %	(Sharma, 2007)
Process gas	50 %	[57]
Waste	26 %	(Koppejan & de Boer-Meulman, 2005)

Table 20: Assumed standard thermal efficiencies

Table 21 presents an overview of the marginal cost calculations for the different types of plants. Note that the blast furnace gas units in Velsen are considered as 'regular' gas units. Due to its low calorific value – around 10% of natural gas – these units are co-fired with natural gas. For the sake of simplicity their marginal costs are assumed to be composed in a manner similar to natural gas fired units.

Unit		Standard efficiency	Type	Unit	Cost / unit	Energy content	Cost / MWh	kg / GJ	Ton / MWh	Cost / ton	Cost / MWh	Cost / MWh	Cost / MWh	Cost / MWh
Brown coal	LC	40%	Lignite	ton	50.000	20000	€ 22.50	101.2	0.911	20	€ 18.21	€ 7.50		€ 48.21
Hard coal (new)	HC-N	42%	Hard coal	ton	79.923	28700	€ 23.87	94	0.806	20	€ 16.11	€ 7.50		€ 47.48
Hard coal (old)	HC-O	35%	Hard coal	ton	79.923	28700	€ 28.64	94	0.967	20	€ 19.34	€ 7.50		€ 55.48
Hydro	HY	100%	Hydro	MJ	0.000	1	€ 0.00	0	0.000	20	€ 0.00	€ 6.60		€ 6.60
Natural gas (CHP)	NG-CHP	45%	Natural gas	m3	0.257	31.65	€ 65.05	56.8	0.454	20	€ 9.09	€ 8.15	€ 29.85-	€ 52.44
Natural gas (CC)	NG-CC	58%	Natural gas	m3	0.257	31.65	€ 50.47	56.8	0.353	20	€ 7.05	€ 4.00		€ 61.52
Natural gas (GT/ST)	NG-T	38%	Natural gas	m3	0.257	31.65	€ 77.03	56.8	0.538	20	€ 10.76	€ 4.00		€ 91.80
Nuclear	NUC	37%	Enriched urani	kg			€ 2.97	0	0.000	20	€ 0.00	€ 0.00		€ 2.97
Process gas	PG	40%	Natural gas	m3	0.257	45.2	€ 51.24	66.7	0.600	20	€ 12.01	€ 4.00		€ 67.25
Waste	WASTE	26%	Waste	ton	10.000	34400	€ 4.02	73.6	1.019	20	€ 20.38	€ 7.50		€ 31.90
Wind	WIND	100%	Wind	MJ	0.000	1	€ 0.00	0	0.000	20	€ 0.00	€ 10.00		€ 10.00
Foreign	GERMANY	100%	HC-O				€ 28.64				€ 19.34	€ 7.50		€ 55.48
Foreign	BELGIUM	100%	NG-T				€ 77.03				€ 10.76	€ 4.00		€ 91.80
Foreign	NORWAY	100%	HY				€ 0.00				€ 0.00	€ 6.60		€ 6.60
Foreign	UNITED KIN	100%	NG-T				€ 77.03				€ 10.76	€ 4.00		€ 91.80

Fuel costs	**Unit**	**Cost**	
Hard coal	ton	79.923	
Hydro	MJ	0	(this value should actually represent the opportunity cost of using the fuel, which itself is free)
Natural gas	m3	0.257381	
Waste	ton	10	
Wind	MJ	0	

Emission rights cost		
CO2 emission rights	€ / ton	20

Table 21: Marginal cost per generation unit type

57 This efficiency is a rough assumption. Given that all process gas fired plants are CHP and co-fired with natural gas, they are considered natural gas CHP plants with an efficiency slightly higher (eff. 50%) than 'normal' natural gas CHP units (eff. 45%). Note that the share of process gas units is very low (28 MW or around 0.1%). This assumption would not have been made if their share was of any significance.

Although Table 21 indicates the marginal cost of each specific type of generation unit, the model adapts this value to reflect different thermal efficiencies. Multiple units of the same type can thus have different marginal costs, which is one of the main contributions of the model as discussed in section 4.3.

Further note that although the water which is used as a 'fuel' in hydro power (imported from Norway) is free, opportunity costs influence the marginal cost of this resource in reality. A hydro power producer may decide not to produce when prices are lower than a particular value in order to allow them to use their resource at a later stage. This study assumes that electricity prices in the Netherlands are sufficiently high for Norwegian hydro power to be imported under all simulation runs and that these costs are sufficiently low to never set the market price (i.e. they are never the marginal accepted offer). Under this assumption it is irrelevant what the precise height of these opportunity costs actually is.

Emission rights cost

Emission rights costs are directly related to production levels and depend on a plant's type fuel, its thermal efficiency, and the cost per ton. Efficient plants produce less CO_2 per MWh produced, which is taken into account in this model. Note that thermal efficiencies are assumed to be fixed for all production levels, although in reality there is usually an efficiency drop if production levels drop below a certain threshold. An emission rights cost of €20 / ton (Sharma, 2007) is used in the base case scenario.

Variable operational cost

Variable operational costs of different types of power plants were found in Sharma (2007), although a remark must be made along with the author's estimate for marginal operational costs of wind (€ 10 / MWh) and nuclear (€ 8 / MWh) power. It is unlikely that these values are true marginal costs, as both types of plants will run whenever possible due to the intermittent nature of the source or very long ramping times. As the marginal costs of these sources is unlikely to ever be the marginally accepted offer, it is very unlikely that this will have an influence, however. Nonetheless, the marginal operational cost of nuclear power is assumed to be zero.

Foreign (DE, BE, NO, UK) supply

The electricity markets of the North-Western European countries are coupled and transmission capacity between these markets is auctioned implicitly. Foreign production capacity is assumed to be offered to the Dutch market at the MCP of that country, which corresponds to the marginally accepted offer. The height of this offer is implemented in the model by assuming the type of marginally accepted unit in the respective country (found in TenneT (2009a)) and subsequently calculating its marginal cost in a fashion similar as above. Table 22 indicates the type of marginal unit per country, its marginal cost (in the base case scenario), and the volume offered (it is assumed that the commercially available transfer capacity is fully utilized).

Note that electricity will be exported to Belgium and United Kingdom in the base case scenario.

Country	Marginal unit	Price / offer (base case)	Volume[58]
Germany (DE – 5)	Hard coal (old)[59]	€ 55.48 / MWh	3080 MW
Belgium (BE – 6)	Natural gas (old GT)	€ 92.58 / MWh	1310 MW
Norway (NO – 7)	Hydro-power	€ 6.60 / MWh	700 MW
United Kingdom (UK – 8)	Natural gas (old GT)	€ 92.58 / MWh	1000 MW

Table 22: Supply from Germany, Belgium, Norway, and the United Kingdom

58 Offered volume is equal to commercially available transfer capacity, see Hers et al. (2009a).

59 High wind availability is assumed for Germany in the base case scenario. If no wind is available, existing or future gas-fired units would be marginal (TenneT, 2009a).

D.1.2 Demand curve

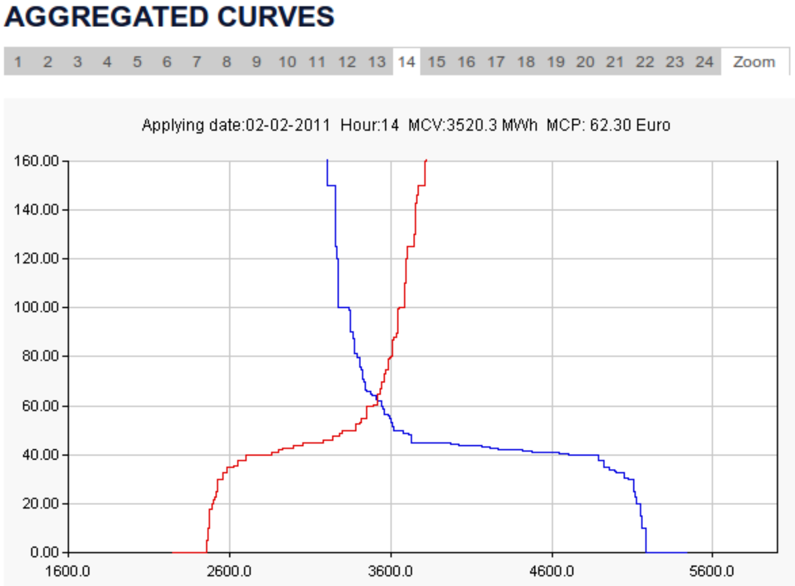


Figure 19: Illustrative supply and demand curves (source: APX)

Different types of electricity consumers respond differently to changes in the electricity price. Households and small businesses generally have fixed price per kWh contracts with retailers and therefore hardly respond to supply (and thus price) variations. Large industrial consumers, about 500 in number, can purchase and sell electricity themselves and can thus respond to these changes. However, given that the economic value of electricity is an order of magnitude of 100 larger than its cost (Ten Donkelaar & Scheepers, 2003), demand, particularly short-term demand, will only respond to price fluctuations slowly. This finding is supported by APX demand curves, which prove to be rather steep around the intersection area, especially during peak hours. This is illustrated by Figure 19 [60].

There are roughly three ways to include demand in the model. First and ideally, the demand elasticities are determined separately for each consumer (or type of consumer) and are included in the model as such. This would require full information on the prices against which (aggregated groups of) consumers would consume a particular volume of electricity. A second, more simplified approach assumes a demand elasticity factor which is applied to all demand and then used to construct a linear demand function. The demand function can be 'scaled' correctly using the MCP-point, which is obtained by finding the intersection of the supply curve (discussed in the previous section) and the actual load. I.e., the sum of all cleared (accepted) demand bids is considered equal to actual historical and projected loads. A third method assumes short-term demand to be entirely inelastic: consumers are not able or willing to respond to price fluctuations that might arise as a result of congestion.

Given the scale and scope of this study, the first option is infeasible as this data is not available and time is too limited to construct even the aggregated version discussed above. The second option would be feasible, but Ackermann (2007) argues that short-term price elasticity is very low[61] and also the precise representation of demand elasticity is not key to the research objective. Considering these facts, the third option is applied and the load is considered entirely inelastic when congestion influences market prices.

Actual load

The demand curve (note that this curve is actually a straight vertical line in this study; see the previous paragraph) is calibrated using data on actual loads. Peak load data on the level of individual substations was provided by TenneT for the period 2010 – 2016. By grouping the data for the individual substations under one out of ten sub-grids and applying a simultaneity factor, and subsequently aggregating the loads of these sub-grids to correspond with the four-node configuration as used in the model, the information in Table 23 was obtained (only showing 2010 and 2016).

60 APX-ENDEX publishes the aggregated curves of market results on a daily basis, after closing day-ahead trading for the next day – http://www.apxendex.com/index.php?id=147

61 This finding in Ackermann (2007) is based upon the Swedish and Norwegian electricity markets.

Node	Peak load (2010)	Share	Peak load (2016)	Share
North Netherlands (1)	2 717 MW	15%	3 098 MW	15%
Ring (2)	13 477 MW	75%	15 363 MW	73%
Maasvlakte (3)	839 MW	5%	1290 MW	6%
Zeeland (4)	1 011 MW	6%	1287 MW	6%
Total	18 043 MW	100%	21038 MW	100%

Table 23: Nodal peak loads 2010 / 2016 (expected) (provided by TenneT)

The original data could not be published in this report due to confidentiality.

Base case demand

For the base case scenario, demand is assumed to be equal to the peak loads as shown in Table 23. Please refer to Appendix G for the electricity demands assumed in the scenarios (if different from the base case).

D.2 Dispatch data

The data used to determine the dispatch of generating facilities given the outcomes of the *Market* sub-model was retrieved from two sources. The larger units were modeled using an overview provided by TenneT which contains the information listed below for all thermal production units > 10 MW_e in the Netherlands. Smaller units were not individually modeled, but were grouped as a particular type of production capacity (i.e. CHP) for every node separately. Modeling these units individually would not contribute to the research objectives, especially when their marginal costs are equal and the units would 'behave' like one large group anyway (this would be the case as efficiencies for these small plants are not known, which is the case).

The remainder of this section will deal with the modeling of large units (>= 60 MW, D.2.1) and small units (< 60 MW, D.2.2). Following the reasoning in Lise et al. (2006), small producers are assumed to be price takers which are not able to artificially influence the market price by themselves. This allows for their inclusion as a competitive fringe that consists of aggregations of small producers by type and location. The capacity limit of 60 MW that is used to distinguish between “larger” and “smaller” units was chosen because this is currently the threshold for production units to either or not be required to participate in the congestion management scheme of the Netherlands.

D.2.1 Units larger than or equal to 60 MW

All units with generation capacities larger than (or exactly) 60 MW were modeled individually on the basis of data provided by TenneT. This information consisted of data in the following categories:

- ✔ * Producer
- ✔ * Congestion region
- ✔ Province
- ✔ Municipality
- ✔ Unit name
- ✔ * Capacity
- ✔ Penta Class
- ✔ Power cycle technology
- ✔ Turbine technology
- ✔ Fuel type
- ✔ Merit category

- ✔ * Merit order
- ✔ Must run (percentage)
- ✔ Efficiency
- ✔ Station name of grid connection
- ✔ Grid connection voltage
- ✔ Grid operator
- ✔ * Commissioning year
- ✔ * Mothballed year
- ✔ * Decommissioning year

(* Data relevant for the model is marked with an asterisk.)

(The sheet itself could not be included in this report due to confidentiality.)

Some data needed to be transformed for the model to work, which is briefly discussed below.

Producer

When determining dispatch, the model needs to look up producer commitments from the Market sub-model and dispatch capacity accordingly. Each producer was assigned a number (in alphabetical order), which has no further meaning but merely serves a technical purpose for the model to work.

Congestion region

Plants listed in the overview are all located in one out of six defined congestion regions. The model, however, only distinguishes between four congestion regions, in line with Hers et al. (2009b). Plants in the regions Flevoland and Noord-Holland are therefore included as being part of the Ring in the model. The only exception to this is the production capacity in Luttelgeest (Noord-Oostpolder; North Flevoland) which is grouped under North Netherlands (congestion region 1). Please refer to Appendix D.3 for an elaboration on the geographical areas that are covered by the different nodes.

Capacity

In principle the capacities for production units follow from this overview directly, but because simulations may be performed for years when a unit is not available (which is the case for planned, under construction, mothballed, and decommissioned units) may occur. Unit capacity is thus represented with an IF statement, which makes a unit's capacity equal 0 if the year assumed in the scenario run is such that the unit is unavailable.

Mothball / decommissioning year

For some power plants a mothball or decommissioning year was provided. I have merged these into a new category called 'out of use'. Plants for which no information was provided, are assumed to be available under all scenarios.

D.2.2 Units smaller than 60 MW

All units with generation capacities smaller than 60 MW were grouped by type, while distinguishing between their nodal locations. This study distinguishes between CHP, onshore wind, and waste, and the values used can be found below. TenneT also provided aggregate figures for a distributed generation category 'other', but because it is unclear what type of units (e.g. solar panels on household roofs) make up what share and its contribution to total generation capacity was small (400 MW), it was not included.

Node	CHP	Onshore wind	Waste
1	603	600	161
2	4057	1599	277.1
3	1435	309	65[62]
4	266	732	0[63]
Source:	(TenneT, 2009a)	Datasheet with all load and DG capacities per station, provided by TenneT (confidential).	Aggregated values on the basis of the overview discussed in section D.2.1.

Table 24: Aggregated units, per node (in MW)

Note that these values rely on the assumption that all greenhouses in the Zuid-Holland province are located in the Westland-area. According to TenneT (2009a) the total small (< 60 MW) CHP capacity in the province Zuid-Holland is 2602 MW, of which 1435 MW is used within the greenhouse industry. It does not make a distinction between greenhouses within and outside the Westland area. The exclusion of the Westland area is, however, highly relevant for this study, because the nodal borders of the congestion regions RN and MV are determined such that they “split” the Zuid-Holland province in two parts. Given that the greenhouse industry is mostly concentrated in the Westland-area, this study assumes all 1435 MW to be located in this area (node MV (3)). The remainder of the decentralized CHP capacity in Zuid-Holland, 1167 MW[64], is thus assumed to be located in the node Ring (RN – 2).

D.3 Transmission data

The following data was identified to be required for the *Transmission* sub-model:

- Nodal border definitions
- N-1 safe grid capacities, for all grids (110 kV to 450 kV) connecting nodes
- Power transfer distribution factors (or approximations thereof) for these grids

Nodal border definitions

Defining nodes is useful only if grid capacities within these nodes internally can realistically be assumed to be at least equal to the capacities connecting these nodes to one another. If this is not the case, the simulation results may not add much value as any result presented would be based upon a false assumption. It is thus important to specify nodal borders in a realistically useful manner. Table 25 below discusses these border definitions for the 'neighboring nodes' within the Netherlands. International nodal borders between the Netherlands and Germany, Belgium, Norway, and the United Kingdom are defined at their respective cross-border connection points. For those unfamiliar with the layout of the Dutch electricity grid, a grid map of the Netherlands is provided in Appendix F.

Neighboring nodes		**Border definition**
North Neth.	Ring	Congestion between the nodes North Netherlands and Ring is expected to occur mainly because large amounts of additional (base load) production capacity are planned for the Eemshaven industrial area. TenneT (2009b, p. 17) shows that

62 Excluding two new units (operational in 2013) of AVR in Rotterdam and HVC Energy in Dordrecht.

63 The two electricity producing waste incineration facilities (BMC in Moerdijk and SITA ReEnergy in Roosendaal) in Zeeland are included in the model separately, so the value for this aggregated category is 0.

64 This is the remaining CHP capacity that is located in the province of Zuid-Holland, which is not located in the Westland-area and therefore included in node Ring (RN – 2): 2602 MW (total CHP capacity in Zuid-Holland) – 1435 MW (CHP capacity assumed to be located in the Westland area / node MV) = 1167 MW.

		2910 MW of new production capacity is expected to become available in 2013 in the Eemshaven area alone. Because significant demand increases are only expected for the Eemshaven area itself, it is more or less irrelevant where the border of these nodes is defined, as long as it is between the Eemshaven area and its connection to the physical infrastructure of the Ring. In consultation with experts from TenneT the border of the nodes North Netherlands and Ring is geographically defined just north of the physical ring infrastructure. Production capacity in Luttelgeest is considered part of the node North Netherlands. This was done because of the expectation that congestion between North Netherlands and the Ring will most likely occur in the North-South direction, so in reality these capacities will contribute to congestion rather than relieve it. Therefore, it is modeled in a way that reflects this expectation.
Ring	Maasvlakte	In 2016 the Maasvlakte area will be connected to the Ring along basically two routes: 1) a 380 kV and a 150 kV connection eastbound in the direction of Rotterdam, and 2) a 380 kV connection in the direction of Westerlee-Wateringen-Bleiswijk. The layout of the various grids between the Maasvlakte area and the 380 kV ring infrastructure will be changed completely in the next few years. This study assumes these changes to be fully implemented when running the model. Given the two 'routes', there are basically also two options for defining nodal borders in a manner such as that areas with only little meshing can be separated: 1) the Maasvlakte region is 'cut off' at Westerlee-Wateringen and Simonshaven-Crayestein, or 2) the region is considered to include a larger part of the Zuid-Holland province, with borders defined at Krimpen, where both routes mentioned above 'meet'. On the basis of discussions with experts within TenneT (Derksen & van Houtert, 2011) the former option was chosen, mainly because this nodal border definition separates 'production areas' (Rotterdam industrial area and greenhouses in the Westland area, mostly generation) and 'consumption areas' (urban areas of Rotterdam, The Hague, and Dordrecht, mostly load). The border between the nodes Ring (RN) and Maasvlakte (MV) is thus located along the 380 kV infrastructures Westerlee-Wateringen and Simonshaven-Crayestein. As all lower-voltage infrastructures will be connected as load pockets[65], these are the only points of exchange between these nodes.
Ring	Zeeland	According to TenneT (2009c) the 150 kV connection between Geertruidenberg and Moerdijk will become a bottleneck in the area between Zeeland and the Ring. The grid element between Moerdijk and Zevenbergschenhoek therefore serves as a suitable border between the nodes Rind and Zeeland. The 380 kV connection between Borssele and Geertruidenberg is cut off near Zevenbergschenhoek (there are no transformer stations, so the exact cut off location between Geertruidenberg and the connection to Zandvliet (B) is irrelevant) and the other parallel 150 kV connection is cut off between Etten and Princenhage. With respect to production capacities > 10 MW this decision is in line with the regional classification used by TenneT in the overview sheet discussed in Appendix D.1.1.

Table 25: Definition of nodal borders

65 A load pocket is created by disconnecting the (usually 150 kV) grids that connect two or multiple areas, which results in a situation where all transports from and to these areas are fed along the 380 kV infrastructure. Such a construction is useful when transports over a lower voltage grid limits the overall transfer capacity between two stations.

N-1 safe grid capacities

The capacities of the power lines that cross the borders of internal nodes can be found in (TenneT, 2009b) and (TenneT, 2009c), and the capacities for international connections are found in (Hers et al., 2009a). Table 26 shows the capacities assumed in the model.

Connection		Capacities	Comments
North Neth.	Ring	1645 MVA (380 kV) 1235 MVA (220 kV)	
North Neth.	Germany	1370 MVA (380 kV)	Note that commercially available capacities are lower (Hers et al., 2009a)
North Neth.	Norway	700 MW (450 kV DC)	(TenneT, 2009b)
Ring	Maasvlakte	4915 MVA (380 kV) -- MVA (150 kV)	2635 MVA (380 kV) / 820 MVA (150 kV) in 2010
Ring	Zeeland	1645 MVA (380 kV) 760 MVA (150 kV)	Rather than a single line there are two parallel 150 kV grids that connect Zeeland and the Ring. On the basis of their PTDFs (power distribution is proportional to their capacities) one can assume these to be one power line with capacity equal to the sum of the individual capacities.
Ring	Germany	3641 MVA (380 kV)	2116 MVA in 2010 (without Doetinchem – Wesel 380 kV connection) Note that commercially available capacities are lower (Hers et al., 2009a)
Ring	Belgium	2995 MVA (380 kV)	Note that commercially available capacities are lower (Hers et al., 2009a)
Maasvlakte	UK	1000 MW (450 kV DC)	(TenneT, 2009b)
Zeeland	Belgium	1645 MVA (380 kV)	Note that commercially available capacities are lower (Hers et al., 2009a)

Table 26: Nodal border capacities assumed in simulation model

Note that losses are neglected in this study. Also, it is assumed that reactive power places no additional loads on the transmission grid, i.e. the ratio between real and apparent power is assumed to be 1 between the nodes. Stated differently: if 1000 MW needs to be transported from A to B, a (n-1 safe) transmission capacity of 1000 MVA suffices. This approach was advised by experts within TenneT in the light of the project scope and required level of model complexity.

Commercially available cross-border capacities

Not all cross-border capacity that is available from a technical and safety point of view is made available to market parties. Because a large part of continental Europe has an integrated electricity system electricity flows imposed by, for instance, transactions, load and dispatch in Poland and Italy have an influence on the flow of electricity on the Netherlands–Belgium and Netherlands–Germany interconnections. If all (physically) available transmission capacity were to be made available to the market, these third-party flows could cause overloading even if the transactions between the Netherlands and its neighbors are perfectly within capacity limits. TSOs therefore set the commercially available transmission capacity lower than what is technically feasible. Due to the fragmented decisions and actions that take place throughout Europe and which all have an influence on the Netherlands, they used to need make rather conservative estimates to ensure reliability of the grid under all circumstances. With the implementation of market coupling in the CWE region more efficient use could be made of the cross-border connections, albeit commercially available capacities are still below the maximum technically feasible capacities.

The values for the commercially available transfer capacities that are used throughout this study are shown in Table 27. The values for the HVDC cables to Norway and the United Kingdom are fixed, but the ATCs between the Netherlands and Belgium and the Netherlands and Germany may fluctuate in reality. The ATC is not equal to the sum of all interconnection capacities, because actual power flows are not divided equally over the various power lines. The ATC thus depends on the current flow patterns and PTDFs and may change over time. For the sake of simplicity this study considers somewhat conservative values of 1750 MW and 4250 MW for transports from/to Belgium and Germany respectively. Note that this study further assumes all electricity to be traded through spot markets, including cross-border trade. Foreign demand and supply volumes are thus based upon these values in the simulation model, as international trade is considered to take place under the market coupling method in all circumstances as was described in section 4.2.4.

Interconnection	**Commercially available transfer capacity**
NL → Germany	4250 MW
NL → Belgium	1750 MW
NL → Norway	700 MW
NL → United Kingdom	1000 MW

Table 27: Commercially available cross-border transfer capacities (TenneT, 2009a)

PTDFs

If two nodes are connected by multiple grids, or if a node is connected to two other nodes, the power distribution over the different available routes is determined by the reactances of the infrastructures. The allocation rate that is obtained after calculating the reactances and resulting power flows is called the power transfer distribution factor (PTDF). Table 30 (below) shows the spreadsheet that was used to calculate the PTDFs, which are used by the model to calculate the loads on separate line segments when a given amount is transported from one node to another.

The tables below provide a summarized overview of the PTDFs calculated in Table 30. Table 28 indicates the allocation factors for nodes that are connected by both 380 kV and 220/150 kV grids, whereas Table 29 shows the outcomes of these calculations with respect to nodes that are connected to more than one other node (NN, RN, ZL, DE, BE). The latter is relevant because not all power flows directly from source to sink, but some of it will take a “detour”. This is the result of electric power flows not being determined by the distance of a route, but rather by the reactance of the path[66]. For instance, power transported from the node North Netherlands to Germany will partly flow over the node Ring if the total electricity flow encounters less resistance when some of the electrons take this other route.

Connection		**Factors**	**Comments**
North Neth.	Ring	380 kV: 0.703 220 kV: 0.297	On the basis of the reactances calculated in Hers et al. (2009a) for the 380 kV (13.7) and 220 kV (32.4) routes connecting North Netherlands and the Ring these factors were obtained.
Ring	Maasvlakte	380 kV: 1.0	In 2010: 380 kV: 0.8 150 kV: 0.2 (Spaan & Rasing, 2010).
Ring	Zeeland	380 kV: 1.0 150 kV: 0.0	According to experts within TenneT it is safe to assume that all power flows via the 380 kV network. Additional reactance is in place to allow TenneT to direct sufficient power away from the 150 kV grid in order to fully use the capacity available on the 380 kV grid.

Table 28: Power Transfer Distribution Factors

66 Note that (total) reactance of a path (upper case X) is a function of both physical line characteristics (indicated by lower case x, in [ohm/km]) as well as distance.

Connection		**Factors**
North Neth.	Ring	0.876 (direct) 0.124 (via Germany)
North Neth.	Germany	0.337 (direct) 0.663 (via Ring)
Germany	Ring	0.931 (direct) 0.069 (via North Netherlands)
Connection		**Factors**
Ring	Zeeland	0.626 (direct) 0.374 (via Belgium)
Ring	Belgium	0.864 (direct) 0.136 (via Zeeland)
Belgium	Zeeland	0.724 (direct) 0.276 (via Ring)

Table 29: Tri-nodal PTDFs (2016)

Germany-Ring is physically connected by three interconnectors: Hengelo-Gronau, Doetinchem-Wesel, and Maasbracht-Siersdorf/Rommerskirchen[67]. The reactance of the Doetinchem-Wesel interconnection was approximated to be 15.282 Ω, which is based on the average reactance of all existing 380 kV lines in the Netherlands. This was calculated by Hers et al. (2009a) and is approximately 0.27 Ω/km.

Power flows between the nodes NN and RN as well as RN and ZL partly flow through Germany and Belgium. The interconnector reactances that are taken into account in the PTDF calculations are only calculated up until the location where the interconnector is connected to the German and Belgian grids. Power that physically flows from NN to RN via Germany also needs to flow from the location where the NN-DE interconnector feeds into the German grid, to the location where it is fed into the Dutch grid at node RN again. In order to calculate the PTDFs one therefore needs to take into account the fact that the internal German and Belgian grids have an influence on the amount of power that flows between Dutch nodes that are connected to foreign nodes in addition to the interconnecting power lines themselves. Because modeling the Germany and Belgian grids in detail falls outside the scope of this study, an additional reactance is assumed which depends on the approximate distance that is traveled by the electricity along these grids.

For Germany –which facilitates a part of the power flows between NN and RN– the average distance between Diele (connected to NN) and Gronau, Wesel, Siersdorf, and Rommerskirchen (all connected to RN) is used to calculate a reactance of 54 Ω (assuming x to be equal to x_{avg} for the Dutch grid, which is 0.27 Ω/km).

For Belgium –which facilitates power flows between RN and ZL– the additional reactance is calculated on the basis of the distance between Zandvliet (connected to ZL) and Meerhout and Lixhe/Gramme (connected to RN), which is approximately 100 km, resulting in a reactance of 27 Ω using x_{avg} for the Netherlands.

67 The transmission lines Maasbracht-Siersdorf and Maasbracht-Rommerskirchen consist of one 380 kV circuit each, but are considered as one N-1 safe connection together.

(The contents of this page could not be shown because they contain confidential data)

Table 30: Grid capacities and PTDFs

Appendix E: Model testing

This appendix elaborates on the verification and validation tests that were performed during this study. For every test the objective (what should it tell us?), relevance (why do we need to know this?), execution (how was it done?), and results (so, what new insights were gained?) will be discussed.

E.1 Verification

During the verification phase the model is reviewed in order to ensure that it is conceptually consistent with its intended structure. Two tests were conducted.

E.1.1 Simulation model coding

What?

Chapter 4 introduced the simulation model by showing a conceptual model that indicated the elements of the electricity system that are relevant for this study. The *simulation model coding* test aims to verify whether the model that was constructed is conceptually matches its design.

Why?

At the time of writing the research proposal for this study, a simulation model was envisioned that would allow research to be conducted that provides an answer to the research questions and fulfills the objectives of this study. Throughout the model specification process it became clear, however, that it would not be possible to create a model that was completely in line with the model envisioned at start. This was mainly the result of a lack of data, but there were also some practical shortcomings in the modeling software (i.e. Excel couldn't deal with some simulation elements as "neatly" as desired).

How?

This test was performed by assessing to what extent the functions the model was intended to perform have actually been included in the model.

The aim of the model was to enable its user to calculate the social surpluses for consumers, producers, and the TSO under different congestion management systems. By comparing the outcomes under these systems one would gain an insight in the differences that exist between them with respect to (the distribution of) congestion costs and resulting incentives. To allow for this, the model would need to be able to determine the plants that would be dispatched given a producer's supply obligations and then calculate the resulting flows that are being imposed on the transmission grid when the pattern of transactions is carried out. When congestion occurs and the transaction pattern can thus not be implemented physically, an iteration would be made to alter the transaction pattern (and, as a consequence, the resulting transmission flows) using the congestion management mechanism currently under evaluation.

Consumer and producer surpluses are calculated by the surface that exists between the height of their bids and offers and the MCP. In short, surplus equals the value that electricity represents to a customer for which they do not have to pay, or the additional revenue a producer gains from selling electricity (i.e. revenue made minus revenue made if being the marginal supplier). For such a calculation one thus needs to know the exact shape of both demand and supply curves, but insufficient knowledge and data was available to model these curves realistically. The supply curve was eventually estimated sufficiently realistic (see Appendix D.1.1), but demand was included as merely a total load value for each node. It is thus impossible to accurately determine consumer surplus using the model.

So?

Because the actual consumer surplus cannot be accurately determined and the producer surplus is based on a somewhat rough assumption, the values that result from the model have no meaning in itself. However, the model does provide useful outcomes with respect to shifts in these surpluses under different congestion management methods. It is thus still valuable for learning about differences under these methods and under different scenarios.

E.1.2 Spreadsheet formula consistency check

What?

The model consists of multiple-tab spreadsheet files with formulas that are all linked to each other in one way or another. This test is meant to verify that all formulas include correct cell references. It is conducted by manually reviewing the different formulas that are used throughout the spreadsheets and by expanding all the cells that are checked for consistency over the range they are supposed to apply to, in order to ensure that every cell in a range contains the correct formula.

Why?

Throughout the specification process some errors were encountered as a result of formulas not including data that was added to the model at a later stage. For example: a value is looked up in the range $A$1:$A$200, but in a later stage this range is extended up to $A$300. If the formula in the cell that is looking up a value is not extended accordingly, the model will not function properly. Because of the iterative modeling process it is important to check for such errors manually.

How?

Of course, not every single cell containing a formula needs to be reviewed separately. Once the first cell of a column in which every cell is supposed to contain the same type of formula is checked, the formula is extended to all the cells in the respective column. This reduces the number of cells that need to be checked to a few dozen, which makes the process rather manageable.

So?

Throughout the simulation process supplier offers are manually[68] entered in the respective auctions. The model is only designed for a particular number of volume-price pairs, and during this verification step the model was adapted in order for it to be able to simulate 160 separate supply offers – which is the number of production units that is distinguished between – without additional modifications.

Apart from some consistency adjustments (e.g. as the one above) no errors were found in the calculation functions used in the model.

E.2 Validation

The validation process is meant to test whether the model produces realistically correct outcomes, and to determine under which conditions this is either or not the case. Four validation tests were performed and these are discussed in the following subsections. All tests are run under the base case scenario.

E.2.1 Extreme conditions

What?

This test determines whether the model responds accurately to extreme conditions in the input values that it may encounter. To this end the model is made subject to extreme values of its input conditions, which are realistically not expected to occur but which the model should in principle still deal with correctly.

Why?

Throughout the model construction process the data that was used was realistic or resembled reality as much as possible. The model *should*, however, also be able to deal with extremely large or small values, i.e. the outcomes produced should be in line with what is expected when these extreme

68 In practice these follow directly from automated marginal cost calculations.

conditions are imposed. If they are not, this indicates that the model is coded incorrectly and its outcomes are thus not valid.

How?

Various input values were deliberately set to an extreme value, i.e. several orders of magnitude smaller or larger than they actually are, and the model was run to see whether the outcomes are in line with what one would expect from these extreme input values.

Input variable	**Expected behavior**	**Model behavior**
Electricity demand (set to zero)	No production, no power flows.	In line with expectations.
Electricity demand (set to zero in NL)	Production for exports only; exports to DE, BE and UK (MCP in NO is lower than marginal accepted offer)	In line with expectations.
Electricity demand (set to zero in node RN)	Excess production in node RN; flows to all other nodes. Possibly congestion.	Node RN indeed has a production surplus which is uncommon under normal conditions, but no congestion arises. This is because the newer production units in nodes NN and MV have lower marginal costs and are therefore dispatched first. Interestingly, the expectation that power would flow away from node RN is not the case. Because of the low MCP as a result of demand in RN being 0, Germany is a net importer of Dutch power. Given the lower cost of production in NN and MV compared to RN, units there produce for the German market. As power from MV to DE must flow through RN, the line RN-MV is used in the direction towards RN.
Electricity demand (node RN: 100,000 MW)	Supply shortage occurs	The model was found unable to deal with a situation where cumulative demand of sufficiently high bids (that should be accepted on the basis of their bid price) exceeds available supply. It accepts a volume equal to the cumulative offered supply volume, but does so on a first-entered-first-serve basis (i.e. the order in which the bids are entered into the model determines their priority, even when no priority was intended). This results in all demand in node 1 (NN) to be accepted and demand in node 2 (RN) to be accepted insofar as sufficient capacity is available, whereas all other demand is rejected, despite the bids exceeding MCP. As it is not possible to determine which demand is met, and which is not, on the basis of market outcomes, and the model has no other rationing mechanism than a market, the model cannot cope with this situation properly.

		Model limitation: Cumulative volume of bids above the price level of the most expensive supply offer may not exceed the total volume offered by producers.
Marginal supply offers (Dutch producers) (all set to zero)	Electricity price 0; large negative surpluses for producers; benefits for consumers and TSO.	In line with expectations. Also note that all cross-border flows are in an exporting direction.
Marginal supply offers (Dutch producers) (all set to 5,000 €/MWh)	Except for imports, demand cannot be accepted anywhere. Because total import capacity is insufficient to meet national demand, a shortage will occur.	This creates a similar situation as when demand in node RN was set to 100,000: some demand can be accepted, but not all, and the model cannot deal with this. The same model limitation as formulated by the "Demand in node RN set to 100,000"-test is found here.

Table 31: Extreme conditions: input values and behavior

So?

The extreme conditions tests revealed an important limitation with respect to the model's abilities: when demand that should be accepted on the basis of the bids' height cannot be supplied because the supply volume is insufficient, the model results are not valid because the volume of accepted demand is determined on the basis of a wrong criterion. The model assumes a priority list on the basis of the position of bids (i.e. bids that are entered at the top have priority over the bids that are entered afterwards, at the same price level) but this is not the case. The problem arises because rather than using a "real" demand curve with bids at different price levels, market demand is considered to be fixed and based upon forecasted loads rather than modeled realistically. It would be possible to adjust the model such that it assigns capacity pro-rata to all bids at an equal price level but because a situation where capacity is so limited that demand cannot be met would indicate much larger problems in the first place it would be rather meaningless to force the model to calculate market outcomes and flows under these conditions in the first place.

E.2.2 Sensitivity analysis

What?

This test aims to identify the variables which heavily influence model outcomes when their values are changed modestly.

Why?

The aim of this test is to gain two main insights: 1) to determine whether the model is not overly sensitive, and 2) to identify those variables that are truly influential and either provide an opportunity for policies to be based upon, or otherwise deserve special attention because they have a great influence on outcomes (both for the model and in reality).

How?

By changing the values of input variables by small amounts (+10% / -10%) and observing the changes in outcome variables, the sensitivity of the model to particular factors is determined. If the influence of a factor cannot be justified on the basis of theory, the model calculations are manually checked to ensure the model's correct coding.

Table 32 shows the sensitivity of the model for small fluctuations in a number of input factors. These factors are tested by observing the response of the following output variables:

- Congested areas

- Congestion on individual lines
- MCP
- Congestion costs (producers, consumers, TSOs)

Input variable	Model sensitivity	Insights
Gas price +10%	No large changes are seen: the marginal accepted offer is increased by 10% because the marginal unit is gas-fired.	On the whole, producers benefit from a higher gas price. The marginal unit is gas fired and raises the MCP by 10%. Revenues are increased for the owners of production units of other types as well, but they do not experience increased costs.
Gas price -10%	Idem.	Opposite of 'Gas price +10%': generator revenues decrease by 10%, consumers benefit. If the gas price would decrease a little further, MCP in the Netherlands would fall below MCP in Germany. This would reverse the cross-border flows which would have a rather large influence on the flows.
Load +10%	No significant influence.	
Load -10%	MCP decreases slightly, because a cheaper unit becomes the marginal accepted offer.	
Load NN +10%	No significant influence.	
Load NN -10%	No significant influence.	
Load RN +10%	No significant influence.	
Load RN -10%	MCP decreases slightly, because a cheaper unit becomes the marginal accepted offer.	
Load MV +10%	No significant influence.	
Load MV -10%	No significant influence.	
Load ZL +10%	No significant influence.	
Load ZL -10%	No significant influence.	
Wind availability +10%	No significant influence.	
Wind availability -10%	No significant influence.	

Table 32: Sensitivity analysis: tested variables and model sensitivity

So?

Sensitivity analysis showed that there are no input variables that disproportionately influence the model. However, running the model with a 10% lower gas price led to the observation that the Dutch MCP might fall below (or rise above) that of its neighboring countries and thereby change the direction of cross-border trade and flows. Further analysis (i.e. running the model while setting the Dutch MCP above German MCP) showed that (internal) transmission flows could indeed become very different when cross-border trade patterns change. Please refer to Chapter 6, which discusses the results of running different scenarios, for the consequences of the reversal of such flows.

E.2.3 Qualitative characteristics

What?

The qualitative characteristics test entails the qualitative assessment of model behavior after one of its input values is changed. Although it is actually designed for a simulation model that is run over time and shows outcome pattern fluctuations that can be qualitatively assessed, a simple variant of this test is applied to the outcomes of this static model. Because it is better suited for a model that is run over time and shows behavior over a certain period, it is performed in a rather limited manner.

Why?

After testing the model for extreme conditions and determining its sensitive elements, the model is now evaluated under 'normal' behavior. This test evaluates the outcomes that are produced by the model and checks whether these are in line with what one would expect.

How?

As was briefly mentioned above, the static nature of the model precludes a full qualitative characteristics test from being conducted. This would require one to obtain an insight in fluctuating model behavior over time, which are not produced by the model. By varying a number of factors, e.g. fuel and emission costs or demand in the different nodes (see Table 33), one can determine whether the outcomes are in line with one's expectations under these circumstances.

Situation	**Expectation**	**Model behavior**
Coal price increases threefold	Gas fired units are dispatched first	In line with expectations.
High wind availability (1.0)	Price decreases, exports increase	Although the intersection point shifted, its new point did not lie at a lower price level due to the step-wise nature of the supply curve. Exports and imports were not affected, because the direction of trade was not affected, and were already at their maximum levels.

Table 33: Qualitative characteristics: evaluated factors and model behavior

So?

The qualitative characteristics test showed that the model responds properly to differences in environmental variables.

E.2.4 Historic data

What?

The historic data validation test compares model outcomes with real, historic data. It is performed by comparing the units that are disptached in the model to the units that were dispatched in reality. The test is done for 2010.

Why?

If the model produces outcomes that are in line with real situations, this is an indication that the model is coded correctly and produces appropriate behavior. Testing against historic data has a major advantage over comparisons with (subjective) expectations: the real situation has already occurred and can serve as a comparison for model outcomes.

How?

All input factors (demand, supply, production capacities, transmission capacities, PTDFs) are set to their 2010 values and the model is run for both a peak and base load case. The outcomes that are produced are subsequently compared to real data on the following:

- Load/capacity ratio per node
- Electricity price
- Imports and exports

So?

This test was eventually not performed because the required data could not be obtained.

Appendix F: Grid map

Figure 20: High voltage grid map of the Netherlands (110 kV - 450 kV)

Legend: *(source: TenneT, 2009a)*

==== 110 kV | ==== 150 kV | ==== 220 kV | ==== 380 kV | ==== 450 kV (HVDC)

Appendix G: Scenarios

Due to its static nature, the conditions under which the model is run are determined by setting input values for a particular moment in time. This allows one to see how the system will respond to different situations that may occur in the future. These situations are described using a number of scenarios, all of which were chosen on the basis of a brief analysis (expert interview) of the needs and desires that exist within TenneT. This section introduces the scenarios that serve as the source for input data that is used in the model during the simulation runs. Every scenario includes a storyline, a discussion of its relevance for this study, and an overview of the quantification of scenario information, which is required for its inclusion in the model. The base case conditions can be found in Appendix D. If not explicitly stated otherwise, the conditions used in the scenario are equal to the base case.

G.1 Scenario 1: Low wind availability in Germany

A large increase in production capacity has turned the Netherlands from a net importer into a net exporter of electricity. As a result of the completion of new production capacity, prices in the Netherlands are now structurally lower than in Germany when wind availability is low. Because the markets are coupled, electricity can easily flow from low price to high price areas, thus creating flows in the direction of the latter. Although lower than in Germany, electricity prices in the the Netherlands still fluctuate around the same level as prices in the United Kingdom. This leads to a situation where the power flow in the BritNed interconnector is frequently reversed, which has important implications for the connection between the Maasvlakte and the Ring. The power flows imposed on the lines connecting these nodes easily vary by up to 2000 MW (from 1000 MW in one direction to 1000 MW in the other) due to the direction of the power flow in this line. This scenario assumes high wind availability for British off-shore wind parks, resulting in British prices to drop below those in the Netherlands.

Relevance

Currently, there is a high degree of uncertainty with respect to electricity flows to and from the Maasvlakte. This is mainly due to the BritNed connector, which directly connects the electricity grids of the Netherlands and Great Britain and can feed in or withdraw as much as 1000 MW at a time. Given that the Maasvlakte as an individual node will have excess production capacity in place (i.e. greater than demand within the same node) and will practically always export, the direction of the power flow has large implications for the connection between the Maasvlakte the rest of the country, specifically for the Ring as this is the only internal node the Maasvlakte is connected to. Depending on the direction of the BritNed power flow this connection is differently affected.

If British prices are higher than those in the Netherlands power will flow towards Great Britain and the connection Maasvlakte-Ring is not expected to be excessively loaded. However, the opposite situation, where the BritNed connection feeds in an additional 1000 MW, TenneT foresees potential congestion in the Maasvlakte-Ring connection, particularly in the absence of the Randstad 380kV-ring[69]. Not only will the "normal" amount of power (i.e. the power that would flow if BritNed is fully used in the westbound direction) need to be transported along these lines, but another 2000 MW would be added: 1000 MW that would otherwise be produced at the Maasvlakte and exported to Great Britain, and 1000 MW produced in Britain and transported to the continent.

Quantified model implications

The marginal unit in Germany is assumed to be an old gas-fired plant (TenneT, 2009a) which results in a bid of 91.80 €/MWh. German demand is assumed equal to the commercially available

69 Randstad 380kV-ring is a planned new 380 kV transmission line connecting the Maasvlakte and the Ring. It consists of two main parts: the North Ring, connecting Beverwijk to Bleiswijk (expected completion: 2014) and the South Ring, connecting Maasvlakte and Bleiswijk (expected completion 2012). In addition, the 150 kV line between Bleiswijk and Krimpen will be upgraded to 380 kV. All elements will have a capacity of 2x2635 MVA (TenneT, 2009b).

interconnection capacity between both countries, which is 4250 MW As a result of high wind availability in the United Kingdom, old coal-fired plants are assumed to be the marginal production unit.

G.2 Scenario 2: Cheap natural gas

Several large discoveries of oil and gas fields around the world have significantly driven down the prices of these fuels, which results in gas fired plants having become cheaper than those that run on coal. Producers rather dispatch a gas fired plant now their marginal costs have dropped below those of coal fired plants, and are supported in this decision by the national government which hopes to reduce carbon emissions by the increased usage of gas rather than coal. The depletion of oil and gas fields that was once considered a major problem is no longer an issue now that new sources are commercially viable to be exploited. Despite warnings from the academic community that the current abundant availability of oil and gas by no means implies the existence of sufficient long-term reserves is neglected as people enjoy the short-term economic advantages of the recent discoveries. Because of the environmental advantages that natural gas has over coal, the call for stringent emission reductions is no longer present with a majority of society and politicians. Although the European emission rights trading system is still in place, the cost of a CO_2 emission right is at an almost record low. And hardly anyone cares.

Relevance

In this scenario coal fired plants are more expensive to run than those that use natural gas, which is expected to have an effect on dispatch decisions and network flows. These flows may change when gas fired plants become cheaper than coal fired plants, because different plants are used than was the case before. Of course, the difference is likely to be minor under circumstances when most plants would be dispatched anyhow – for instance during (regular) demand peaks or if electricity prices on decrease on the whole, resulting in increased demand. This scenario is thus run with moderate demand, with a real change in the plant dispatch patterns.

Quantified model implications

This scenario assumes a low cost of natural gas (€ 0.10 / m^3), which reduces the marginal costs of gas fired power plants to a level below those of most coal-fired units (except for some very new and efficient plants). Also, BritNed is assumed to feed into the Dutch grid at full capacity because cheap natural gas has driven British prices down to a level below the Dutch market price.

Natural gas price: € 0.10 / m^3

Price of CO_2 emission rights: € 10 / ton

Import from United Kingdom: 1000 MW

G.3 Scenario 3: Green Revolution

Despite a temporary drop in 2009 due to the worldwide economic crisis, prices of fossil fuels have continued to climb. This has made investment in renewable energy sources more attractive, although the main driver behind the investments originated from increased attention and support from the Dutch national government. An era of Green Revolution has begun and has led to several major wind parks in the North Sea. There is consensus among government, population, and environmental organizations that offshore wind parks are the best option to mitigate climate change and (foreign) fossil dependency in a country as densely populated as the Netherlands. These wind parks do, however, create additional transmission needs which cannot always be met by the current grid. In total 900 MW is fed into the Dutch transmission grid at the Eemshaven (node NN), 1513 MW in the province Noord-Holland (node RN), and 775 MW in the province Zuid-Holland (node MV). Transmission capacities between Eemshaven / Maasvlakte and the Ring have not been increased and thus remain in their 2015 state.

Relevance

Large scale application of wind power in the Netherlands almost inevitably leads to offshore wind parks, due to high population density. If these wind parks are connected to the transmission grid at coastal nodes[70] where production capacity is already expected to increase, there is a realistic possibility that congestion is further increased. With respect to congestion management it is thus relevant to gain an insight into the effects this has for the development of congestion in the grid.

Quantified model implications

Over 3 GW of additional offshore wind power capacity has been constructed, assuming that all projects that had obtained a construction permit by 2010 have been realized (Noordzeeloket, 2009). This capacity is connected to the nodes North Netherlands and Maasvlakte (see Table 34). It is assumed that the wind parks produce at full capacity at the moment simulated by this scenario.

Node	**Offshore wind capacity (rated)**	**Additional information**
NN (North Netherlands)	900 MW	Construction permits for three wind farms north of Groningen are granted to ZeeEnergie C.V. According to Zee Energie (2010) each of these parks will consist of approximately 60 turbines with rated capacities of 5 MW.
RN (Ring)	1513 MW	Breeveertien II (350 MW) – Airtricity (Boyle, 2007) Brown Ridge Oost (282 MW) RWE (Reuters, 2009) Den Helder I (350 MW) – Airtricity (Airtricity, 2009) Q4-WP (78 MW) – Q4-WP BV (Reuters, 2009) Q10 (153 MW) – Eneco (Reuters, 2009) Tromp Binnen (300 MW) – RWE (RWE, 2010)
MV (Maasvlakte)	775 MW	Beaufort (279 MW) – NUON (Reuters, 2009) Scheveningen Buiten (212 MW) – Evelop (Reuters, 2009) West Rijn (284 MW) – Airtricity (Boyle, 2007)

Table 34: Assumed offshore wind capacity under 'Green Revolution' scenario

G.4 Scenario 4: Code Red

An exceptionally hot summer has caused temperatures of inland waters such as rivers and canals to rise above 23°C. In order to prevent exceeding the maximum temperature thresholds set to protect the environment, several power plants are forced to shut down. Thermal power plants heat up the cooling water they use by approximately 7°C and thus exceed the maximum allowed cooling water release temperature of 30°C. Available reserve capacity is down to 200 MW and TenneT proclaims a code red situation, because there is a serious risk of physical power shortages to arise as a result of demand exceeding supply. Consumers of electricity do not appear to respond to the code red situation and continue to use power as they would normally do.

Furthermore, the scenario assumes that similar cooling water problems have arisen in Germany which has resulted in an old gas fired plant being the marginal unit.

Because all units that are shut down are located at non-coastal locations (node RN and ZL) and use rivers and lakes as a heat sink, power flows from coastal areas (nodes NN and MV) increase to serve the load. Wind availability is very low so the wind farms connected to node RN cannot mitigate the drop in supply. Plants located near the coast (particularly Maasvlakte and Eemshaven) are not affected, as they can continue to use the (colder) North Sea water for cooling.

Relevance

This scenario is relevant because the plants that would be affected by cooling water regulations first are nearly all connected to the Ring (node 2, RN) or located in Zeeland (node 4, ZL). If

70 This is likely, because construction of power lines in order to feed in at other, more inland, locations is expected to be very difficult to realize (Hommes et al., 2011).

production drops at these nodes, electricity will need to be imported from other nodes. This includes Maasvlakte and North Netherlands, which are expected to already export to the Ring under normal circumstances due to excess production capacity being available in the Eemshaven and the Maasvlakte. Additional need for power from these sources may place additional loads on the network which may not be feasible.

Quantified model implications

The model assumes the plants at coastal locations (nodes Eemshaven and Maasvlakte) to produce as usual, whereas several plants connected to the Ring and Zeeland are assumed to be regulated down (see Table 35 below). The ring is geographically located inland (with the exception of North Holland) and plants connected to it thus cannot use sea water for cooling. The following units' production is affected:

Producer and unit	**Production [MW] (from / to)**	
Node RN		
Electrabel – FL-40 (Lelystad)	450	250
Electrabel – FL-50 (Lelystad)	450	250
Electrabel – G-13 (Nijmegen)	593	300
Essent – CC-C1 (Maasbracht)	840	450
Essent – CC-C2 (Maasbracht)	464	250
Essent – CC-D (Maasbracht)	1300	700
Essent – GE-1 (Geleen)	150	100
Essent – SW-1 (Geleen)	241.5	150
Nuon – BUG (MC-7) (Buggenum)	235	125
Nuon – LWE6 (Utrecht)	235	125
Nuon – MK12 (Utrecht)	210	150
Node ZL		
Intergen – Intergen 3 (Moerdijk)	900	600
C.GEN – C.GEN 2 (Vlissingen)	800	600
Sloecntr. BV – SLOE10 (Vlissingen)	435	300
Sloecntr. BV – SLOE20 (Vlissingen)	435	300
DELTA – SLOE30 (Vlissingen)	430	300
EPZ – BS12 (Borssele)	406	250
EPZ – BS30 (Borssele)	480	400
TOTALS	9054.5	5600
Total capacity decrease		*– 3454.5*

Table 35: Production units regulated down under 'Code Red' scenario

Note that the Amercentrale in Geertruidenberg, which is also part of node RN, has a cooling tower available and is assumed to be able to continue to operate normally and produce at normal levels.

MCP Germany: € 91.80 / MWh

Wind factor: 0.1

Appendix H: Simulation results

The scenarios introduced in Chapter 5 were all run by the simulation model to find out whether congestion would occur under them. If the scheduled flows would indeed result in congestion, all four congestion management mechanisms were applied in order to find out what the differences in their performance exist in terms of congestion costs[71], their distribution, incentives, and the possibilities to exert market power.

This appendix presents the results of running the model under the scenario conditions specified in Chapter 5. In the following sections it will discuss the utilization of the transmission grid (both qualitatively and quantitatively), analyze the underlying cause of that particular grid utilization pattern (primarily on the basis of dispatched capacities), and present the (quantitative and qualitative) results of applying the four congestion management methods, if applicable. This is done separately for each scenario. At the end of each section a brief summary is provided that contains the most important outcomes from running the simulation model under those scenario conditions.

Scenario 0: Base case

Under base case scenario conditions no congestion will occur. The completion of the Randstad 380 kV grid infrastructure and the creation of a load pocket for the Rotterdam industrial area will be sufficient to cope with the increased production capacity in the Maasvlakte-node.

Grid utlization [MVA / MVAmax] [%]							150/220 kV	380/450 kV
1	North Netherlands	NN	----->	2	Ring	RN	10%	17%
1	North Netherlands	NN	<-----	5	Germany	DE		14%
1	North Netherlands	NN	<-----	7	Norway	NO		100%
2	Ring	RN	<-----	3	Maasvlakte	MV	0%	60%
2	Ring	RN	<-----	4	Zeeland	ZL	0%	8%
2	Ring	RN	<-----	5	Germany	DE		94%
2	Ring	RN	----->	6	Belgium	BE		25%
3	Maasvlakte	MV	----->	8	United Kingdom	UK		100%
4	Zeeland	ZL	----->	6	Belgium	BE		38%

Figure 21: Base case scenario: Uncongested scheduled flows

Reasons for utilization pattern

Under the base case scenario the model is run under rather normal day-to-day operations, which are anticipated by TenneT and which have led to some transmission expansions, most importantly the Randstad 380 kV ring. The HVDC interconnections with Norway and the United Kingdom are used to their full extent in the direction that is economically expected to be generally advantageous (NO → NL and NL → UK). In principle the same applies to the interconnections with Germany and Belgium as well, except that these are "regular" AC connections and are thus subject to fluctuations in flow patterns in the continental interconnected European transmission grids. In order to prevent international congestion on these interconnections TenneT can alter the nominated ATCs before the European market coupling mechanism is used to calculate the trade flows between these countries. Therefore, the high utilization rate of 95% does not indicate that grid capacity is becoming insufficient, but rather shows that efficient use is made of available capacity (note that the values in the model exclude the safety margins that are still available. If the load of a power line is exactly equal to 100%, this means that – even under the N-1 constraint – there is still some capacity left to accommodate unexpected changes in the flow pattern, insofar as these lie within realistic margins).

Market concentration

Under the base case scenario there is no dominant producer without which demand cannot be met.

71 Note that the absolute consumer surplus values do not reflect reality, as was discussed in section 3.3.2.

Without the largest producer (Electrabel) demand can still be met 1.54 times. There are differences among the different Dutch nodes, however. Node RN separately would face the dominance of a supplier if there was no trade possible with other areas. At least two of the three largest producers (Essent, Nuon, and Electrabel) would be required to meet demand in that situation. In node MV, on the contrary, more than four times the demand could be met without the largest producer (E.ON). Given that no congestion arises in the base case scenario, the RSI value for the Netherlands as a whole applies.

Market concentration	**Residual Supply Index (RSI)**
Netherlands	154%

RSI per node		
1	NN	194%
2	RN	76%
3	MV	404%
4	ZL	370%

Table 36: Base case scenario: market concentration per node

H.1 Scenario 1: Low wind availability in Germany

When German prices increase to a level above those in the Netherlands and the United Kingdom, as happens in this scenario, a net flow of electricity will occur between the Netherlands and Germany. This flow is the result of both the dispatch of units in the Maasvlakte node as well as BritNed feeding in to the Dutch grid. It is important to realize that the direction of the BritNed flow has a large impact on the transmission infrastructure between the nodes Maasvlakte and Ring, because the difference between 1000 MW flowing in one direction and the same amount of power flowing in the other (i.e. -1000 MW in the same direction) results in a load difference of 2000 MW on the MV-RN infrastructure, given that the dispatch pattern in the Netherlands is not affected.

Under the *Low wind availability in Germany* scenario congestion occurs in the transmission infrastructure between the nodes MV and RN. The available transmission capacity (4915 MW) would be exceeded by 1292 MW, or 26%, if flows were implemented as scheduled. This is shown by Figure 22 below.

Grid utlization [MVA / MVAmax] [%]							150/220 kV	380/450 kV
1	North Netherlands	NN	<-----	2	Ring	RN	5%	9%
1	North Netherlands	NN	----->	5	Germany	DE		17%
1	North Netherlands	NN	<-----	7	Norway	NO		100%
2	Ring	RN	<-----	3	Maasvlakte	MV	0%	126%
2	Ring	RN	<-----	4	Zeeland	ZL	0%	80%
2	Ring	RN	----->	5	Germany	DE		93%
2	Ring	RN	<-----	6	Belgium	BE		0%
3	Maasvlakte	MV	<-----	8	United Kingdom	UK		100%
4	Zeeland	ZL	----->	6	Belgium	BE		89%

Figure 22: Scenario 1: Uncongested scheduled flows

Extent of congestion

The amount of congestion, indicated using the ECI that was introduced in section 3.3.1, is provided by Table 37. The ECI value indicates that only 10.58% of the available non-dispatched capacity in the area downstream of the congested line needs to be dispatched in order to solve congestion.

Congested zone	Constrained capacity	Initially non-dispatched capacity	ECI
North Netherlands Ring Zeeland	1291.8	6908.0 4002.2 1304.0 0.0	10.58%
TOTALS		12214.2	

Table 37: Scenario 1: Extent of Congestion Index

Reason for grid utilization pattern

It is important to point out that congestion arises despite the fact that not even all available production capacity at the Maasvlakte is dispatched. The level of Dutch electricity prices in such a scenario (€ 61.52 / MWh) results in a dispatch of 6495 MW at the Maasvlakte, which corresponds to 82.1 % of the total available capacity of 7911 MW. However, congestion would not necessarily increase if the remaining units were to be dispatched as well. This highly depends on the circumstances that would lead to such additional dispatch.

Let us consider a steep increase in demand, nation-wide and proportional among all nodes. Assuming all other factors equal, this would lead to a higher electricity price as a result of which additional units are dispatched. Because production capacity at the Maasvlakte is relatively new and efficient compared to the rest of the country, a relatively large share of units is already dispatched because of their lower marginal costs (82.1 % vs 56.1% for nodes NN, RN, and ZL together). If the nation-wide (uncongested) electricity price were to increase this may lead to additional dispatch on the Maasvlakte as well, but would likely result in an even larger increase of capacity in the rest of the country, possibly alleviating congestion.

Market concentration

Neither in the upstream area, nor in the downstream area is the market concentrated to an extent that one producer is absolutely necessary to meet demand. However, Table 38 shows that the surplus of production in the not-congested region (Maasvlakte) is much larger than in the congested region (remaining parts of the Netherlands): if the largest producer, E.ON, does not dispatch any units, the remaining producers together still have more than four times the capacity available to meet demand in this node. In the congested zone the producers other than the largest only have an excess capacity of 30%, which is still sufficient in the sense that there is no dominant market player.

Market concentration	Residual Supply Index (RSI)
Netherlands	154%
Not-congested region	404%
Congested region	130%

Table 38: Scenario 1: Market concentration

H.1.1 Basic system redispatch

Market price	**€ 61.52**	
Coff price (range)	€ 60.55 … € 61.52	(in € / MWh)
Con price (range)	€ 61.52	

Congestion cost – BSR	Surplus uncongested	Surplus congested	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 270,627	€ 0
- Not congested area	*€ 67,360*	*€ 67,360*	*€ 0*
- Congested area	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 0	€ 231-	€ 231-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,929***	***€ 3,183,698***	***€ 231-***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,998***	***€ 3,296,767***	***€ 231-***

Table 39: Scenario 1: Congestion cost under basic system redispatch

Congestion costs arising from the application of basic system redispatch are fully allocated to the TSO, which is responsible for both "selling" constrained off rights (i.e. the right for a generator to not have to produce any electricity, while still being allowed to sell an amount of power to a market or customer) as well as for buying compensatory power from generators in the downstream zone. As this compensatory power will be produced at a higher marginal cost, the difference between the cost of compensatory power and the benefit from selling *constrained off* rights must be borne by the TSO. Under the *Low wind availability in Germany* scenario this cost equals the rather modest sum of € 231. Note that this is the total cost for solving all 1292 MWs of congestion for one full hour, and not a cost per MWh.

Annual congestion cost estimate

An hourly cost of €231 would amount to approximately € 2 mln. annually, if this amount of congestion were to occur during every hour in a 8760-hour year and generator offers would not change. Although it is important to point out that policy should not the be made on the basis of such a rough extrapolation of a single hourly outcome, which is also based upon very specific scenario conditions, it nevertheless raises the question whether other estimates of congestion costs under basic system redispatch are fully accurate. These estimates expect annual congestion costs to be one or two orders of a magnitude larger (Hakvoort et al., 2009; Hers et al., 2009b). For a more conclusive answer one should construct a continuous model which allows for the calculation of congestion costs during 8760 separate hours, which makes the system subject to a variety of scenarios and market conditions. An important aspect of such a model would be realistically modeling all existing and planned production units, using detailed data on their production costs and available capacities. Nonetheless, as the scenario run in the current study is rather extreme in itself already, it is likely that actual congestion costs would be below 8760 [h] · 231 [€ / h] = € 2 mln., as throughout the year that would also be scenario conditions that lie more closely to one of the other scenarios simulated during this study – during which there is no congestion (cost).

Height of congestion cost under the *Low wind availability in Germany* scenario

The reason for congestion costs being lower than expected is that there is a rather wide range of production units, both inside and outside the congested zone, that produce around equal variable cost. As a result of this cost structure the benefits from *constrained off* power are at or near MCP, while the cost of acquiring compensatory *constrained on* power are also at or only slightly above this level, keeping the net cost for the TSO limited.

Incentives

Consumers:	Because the TSO may incorporate the costs of congestion into its transmission tariffs (which are variable only for consumers in the Netherlands) the cost of congestion may eventually be allocated to consumers in a socialized manner. If this situation occurs, there is a risk that no measures are taken to avoid congestion by any party: producers are not affected to begin with, the TSO transfers its costs, and the incentive that might be provided to those consumers that could solve congestion by adapting their demand patterns because they are located inefficiently, only experience a "watered down" congestion cost incentive which is spread out over all consumers – including those that are already located efficiently.
Producers:	Producers are not financially affected when basic system redispatch is applied and can behave as if there are no transmission constraints. No incentives are provided.
TSO:	The application of basic system redispatch allocates the cost of congestion to the TSO, which is provided an incentive to invest in transmission capacity in order to avoid congestion and the resulting costs.

H.1.2 Market splitting

Market price	Optimal dispatch	Congestion	
Not-congested zone	€ 61.52	€ 60.55	(in € / MWh)
Congested zone	€ 61.52	€ 61.52	

Congestion cost – Market splitting	Surplus uncongested	Surplus congested	Surplus difference (congestion cost)
Consumers	€ 2,913,302	€ 2,914,560	€ 1,258
- Not congested zone	*€ 178,638*	€ 179,896	€ 1,258
- Congested zone	*€ 2,734,664*	€ 2,734,664	€ 0
Producers	€ 270,627	€ 265,321	€ 5,305-
- Not congested zone	*€ 67,360*	*€ 62,054*	*€ 5,305-*
- Congested zone	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 0	€ 4,792	€ 4,792
TSO (int'l.)	€ 113,068	€ 112,093	€ 975-
Total national SW	***€ 3,296,998***	***€ 3,296,767***	***€ 231-***
TSOs foreign	€ 113,068	€ 113,068	*€ 0*
Total SW	***€ 3,410,066***	***€ 3,409,835***	***€ 231-***

Table 40: Scenario 1: Congestion cost under market splitting

When market splitting is applied to manage congestion under this scenario producers experience a loss in surplus. Dispatch is sub-optimal, but because the market price in the congested area has not increased (the additionally dispatched capacity was offered at an equal marginal offer) they receive no compensation whatsoever. In the not-congested (excess capacity) area the market price has decreased, resulting in a loss of surplus for generators. Consumers in the not-congested (excess production capacity) area gain from a slightly lower market price (down to € 60.55 from € 61.52).

The TSO profits from congestion under this scheme, because it can buy power from the not-congested zone at € 60.55 / MWh and sell it in the congested zone at the slightly higher price of € 61.52 / MWh. With respect to international trade the TSO experiences a double loss, however. First, its profits from selling British power in the (split) Dutch market are down, because the MCP in the not-congested zone that is connected to the UK has gone down. As was discussed in Appendix C.2.4, this study assumes that TSOs at both ends of the interconnector receive half of the profits that are made from buying power in a cheap area and selling it in an expensive area. The same loss of surplus would apply to the British TSO, which receives the other half of the international profits from UK-Dutch power transports. However, given that European law states that internal congestion must be treated as a national problem rather than artificially using interconnections and international trade to solve constraints, the British TSO should receive the market price that was originally determined when the Dutch market was not yet split. The consequences of applying market splitting in the Netherlands should therefore be borne nationally and should not be imposed on international trade. As a result, Dutch TSO TenneT experiences a double loss: not only is its surplus from international trade down, it must also bear the cost that is necessary to pay the original (non-split) market price to the British TSO for the international trade volume.

Incentives

Consumers:	Consumers are provided with an incentive to increase demand in the upstream area compared to the downstream area, which could have an influence in two ways: 1) it provides an incentive for consumers to locate themselves in the area with excess production (lower MCP) than with a shortage of production (higher MCP) (long-term effect), and 2) the lower electricity price may lead to increased electricity demand by existing users which may decrease the scheduled transfers from the upstream to the downstream area, thereby decreasing the extent of congestion (short-term effect). The latter effect would only be present in the upstream area, as the MCP in the downstream area does not change from the initial non-split level.
Producers:	Market splitting decreases the MCP in the Maasvlakte-area, which has an excess of production capacity. This results in the producer surplus to shrink, thereby making it less attractive to invest in this area.
TSO:	TenneT would benefit from the market splitting mechanism, by buying power in the cheap, upstream area and selling it at a higher price in the area downstream of congestion. With respect to international trade a small cost is allocated to TenneT, however, as it must compensate its British counterpart for the price decrease in the Maasvlakte area. TenneT still has a net benefit of € 4305, which essentially takes away its incentive to solve the congestion. According to EMCC (2011) this potentially perverse incentive is mitigated by laying down that all congestion rents for TSOs must be invested in grid development. In this manner the parties responsible for congestion essentially pay for the expansion of the transmission grid that should eventually solve congestion in the first place.

H.1.3 Market coupling

Market price	Uncoupled	Coupled	
North Netherlands	€ 61.52	€ 61.52	
Ring	€ 85.37	€ 61.52	
Maasvlakte	€ 44.00	€ 60.55	
Zeeland	€ 44.00	€ 61.52	(in € / MWh)
Germany	€ 91.80	€ 91.80	
Belgium	€ 91.80	€ 91.80	
Norway	€ 6.60	€ 6.60	
United Kingdom	€ 55.48	€ 55.48	

Congestion cost – Market coupling	Surplus uncoupled	Surplus coupled	*Coupling benefits*	Surplus with optimal dispatch	*Difference MC / OD*
Consumers	€ 2,485,420	€ 2,914,560	*€ 429,140*	€ 2,913,302	*€ 1,258*
Producers	€ 180,040	€ 265,321	*€ 85,281*	€ 270,627	*€ 5,305-*
TSO (national)	€ 0	€ 4,792	*€ 4,792*	€ 0	*€ 4,792*
TSO (int'l.)	€ 0	€ 112,581	*€ 112,581*	€ 113,068	*€ 487-*
Total national SW	***€ 2,665,461***	***€ 3,297,254***	***€ 631,793***	***€ 3,296,998***	***€ 256***
TSOs foreign	€ 0	€ 112,581	*€ 112,581*	€ 113,068	*€ 487-*
Total SW	***€ 2,665,461***	***€ 3,409,835***	***€ 744,374***	***€ 3,410,066***	***€ 231-***

Table 41: Scenario 1: Congestion cost under market coupling

The outcome of applying market coupling closely resembles the surpluses of market splitting, although the cost allocation is slightly different. In theory and under perfect competition, market splitting and market coupling should yield the same results in terms of congestion costs and their distribution. Both mechanisms divide a system in congestion zones and aim to create single price zones that cover areas as large as possible. The difference between the methods lies in their approach to achieving this (these) price zone (price zones): while market splitting first assumes a market without transmission constraints and only distinguishes between zones when a constraint is found to be binding, market coupling assumes separate zones and seeks to create one single price area, or a number of single price areas that is as small as possible, in second instance. The eventual outcome, however, should under ideal circumstances be the same, as optimal dispatch in terms of social welfare is found under an exactly similar outcome.

A difference is found with respect to the surpluses from international trade, however. This study, in line with European legislation, assumes that congestion is in principle a national problem. When market splitting is applied, foreign TSOs should not 'notice' the fact that the Netherlands experiences congestion internally. Market splitting – as well as the other congestion management mechanisms – are thus applied in the light of congestion being a solely national affair. Because the market coupling mechanism distinguishes between fixed congestion zones, it can be integrated in the European market coupling mechanism, thereby clearing the four Dutch congestion areas simultaneously with the rest of the CWE region. The Netherlands is thus no longer considered as one market to begin with, but as four separate markets. Congestion between them no longer constitutes "national congestion" that is the responsibility of a TSO, in the light of the European market coupling mechanism, but is equal to congestion between e.g. Germany and France or Belgium and the Netherlands (in its current single area form).

The surpluses from international trade should in this case no longer be regarded as trade between the Netherlands and Germany, Belgium, Norway, and the United Kingdom, but as trade between North Netherlands and Norway, North Netherlands and Germany, the Ring and Germany, the Ring and Belgium, Zeeland and Belgium, Maasvlakte and the United Kingdom. The implication with respect to congestion cost distribution is that the surpluses that would be gained by the foreign TSOs is no longer calculated as trade with "the Netherlands", but as trade with the separate zones. In case of congestion these surpluses can change just as international trade surpluses may change, and the Dutch TSO is no longer responsible for "guaranteeing" the payment of a single Dutch electricity price as it would be under the market splitting mechanism.

Note that apart from the international cross-border trade internal Dutch trade also constitutes "cross-border" trade. The only exception is that this "cross-border" trade does not cross international borders and therefore only a single TSO (TenneT) is involved, but it is regarded as cross-border trade nonetheless.

Incentives

The same incentives as under market splitting apply (see H.1.3).

Market concentration

Although the same figures as shown in Table 38 apply when markets are coupled under the market coupling mechanism, Table 42 is added to illustrate the differences in RSI among the nodes. It clearly shows that in node Ring there would be a dominant player that is required to meet demand if there would be no opportunities for trade among the separate different markets. Without Essent only 76% of demand could be met by all other producers together. Nuon and Electrabel also hold important positions – without these, only 79% and 93% of demand could be met, respectively, in a fully uncoupled situation.

Market concentration	Residual Supply Index (RSI)
Netherlands	154%

RSI per node		
1	NN	194%
2	RN	76%
3	MV	404%
4	ZL	370%

Table 42: Scenario 1: Market concentration per node

H.1.4 APX-based method

Market price		
Consumers	€ 61.52	
Generators not-congested zone	€ 61.52	(in € / MWh)
Generators congested zone	€ 61.52	

Congestion cost – APX-based	Surplus uncongested	Surplus congested	Surplus difference (congestion cost)
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 270,396	€ 231-
- Not congested area	*€ 67,360*	*€ 67,129*	*€ 231-*
- Congested area	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,929***	***€ 3,183,698***	***€ 231-***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,998***	***€ 3,296,767***	***€ 231-***

Table 43: Scenario 1: Congestion cost APX-based method

Congestion costs arising under the APX-based method are created by a difference between the height of the compensatory *constrained on* power that must be aquired by the TSO and the (uniform) MCP that is paid by consumers. If these differ, this results in a congestion cost that is borne by the TSO in first instance, but subsequently transferred to producers in the upstream area up to the extent that, after constraining off a volume sufficient to solve congestion, the producer offering at the highest accepted price level, still has a surplus of zero (or positive).

The congestion cost of € 231 arising from generators having to dispatch economically sub-optimal units is fully allocated to generators in the area upstream from congestion under the APX-based method. These generators have to decrease their output which would be partly generated using units that produce at a cost below MCP, but as a result can no longer produce electricity. Instead, more expensive units need to be dispatched in the downstream congested area. As the compensatory power is produced at exactly MCP, the TSO does not need to seek compensation from the upstream area producers, which limits their surplus loss to the decrease in profitable production (i.e. the units that would be able to produce below € 61.52 / MWh but are now regulated down).

Incentives

Consumers: Consumers are exempted from being involved in the congestion management scheme under the APX-based method. This allows a uniform pricing structure to be kept in place, which has as a consequence that consumers are not provided with an incentive to behave efficiently.

Producers: Upstream producers experience a loss in surplus, because those *constrained off*, some of which offered electricity below MCP, no longer gain a surplus at all. The compensatory power is acquired at exactly MCP, resulting in a surplus of exactly zero for the *constrained on* producers and thus a net societal loss from sub-optimal dispatch. This creates an incentive for producers not to invest in production capacity that runs at a cost near MCP in the upstream area, because in case of congestion they run the risk of being constrained off and not being compensated for this. Cheap generators that offer at a sufficiently low cost would not be affected by the application of the APX-based method and therefore do not experience any locational incentive from this method.

Electricity produced from renewable sources is exempted from taking part in the congestion management scheme under the APX-based method, but as no renewable producers would have been constrained off in the first place this has no influence.

TSO: The cost of acquiring compensatory *constrained on* power is equal to the MCP, which means that no cost is involved for TenneT and no financial compensation needs to be sought from the upstream producers.

H.1.5 Conclusions Low wind availability in Germany

Although the transmission grid is expanded with the construction of the Randstad 380 kV infrastructure, congestion may still occur when large amounts of electricity flow eastward between the nodes MV and RN. An important factor here is the direction of the flow using BritNed, which causes a load difference of as much as 2000 MW for the grid elements between the Ring and Maasvlakte if the flow direction changes. However, despite the fact that the capacity that needs to be redispatched is quite large (1292 MW), congestion costs remain small. This is caused by the large availability of production capacity at or around the same marginal cost. If capacity needs to be redispatched in such a situation, the units that are constrained on produce at (almost) equal cost as those that were constrained off, thus resulting in a near-zero net surplus.

Table 44 provides an overview of the congestion cost distribution under the various congestion management methods. In the last column it also includes the welfare difference between coupled markets under the market coupling mechanism and the outcome of the situation in which the nodes would not have been coupled and would each need to fulfill their internal demand with the internally available production capacity.

Congestion cost Scenario 1	BSR	MS	APX	MC	Coupling benefits
Consumers - NC zone - C zone	 € 0 € 0	 € 1,258 € 0	 € 0 € 0	€ 1,258	€ 2,913,302
Producers - NC zone - C zone	 € 0 € 0	 € 5,305- € 0	 € 231- € 0	€ 5,305-	€ 270,627
TenneT - National - International	 € 231- € 0	 € 4,792 € 975-	 € 0 € 0	 € 4,792 € 487-	 € 0 € 113,068
National SW	**€ 231-**	**€ 231-**	**€ 231-**	**€ 256**	**€ 3,296,998**
Foreign TSOs	€ 0	€ 0	€ 0	€ 487-	€ 113,068
Total SW	**€ 231-**	**€ 231-**	**€ 231-**	**€ 231-**	**€ 3,410,066**

Table 44: Congestion cost distribution under scenario 1

Basic system redispatch, market splitting, and the APX-based method all result in equal national congestion costs. Market coupling, however, allows for some of these costs to be transferred to foreign TSOs that are connected to the Dutch electricity system. This is the result of the assumption that under market coupling, internal congestion is not merely a national problem but considered in the light of the European market coupling mechanism. TenneT therefore does not need to ensure that foreign TSOs that make use of the interconnections with the Netherlands benefit as if the Netherlands were one single node, as is the case with the other congestion management methods.

H.2 Scenario 2: Cheap natural gas

Although a scenario in which cheap natural gas results in an inflow from the United Kingdom and net exports to Germany, which resulted in congestion under the *Low wind availability in Germany* scenario, it does not lead to congestion in this situation. The available coal fired plants on the Maasvlakte (with a combined capacity of almost 3,000 MW) are not dispatched. Instead, demand is met by gas-fired plants elsewhere in the country. The inflow from the United Kingdom can be accommodated by the transmission infrastructure between MV and RN, which experiences a higher utilization rate than under the Base case scenario (see Figure 23) but is not exceeded.

Note that this scenario assumes that the marginal costs of gas fired plants are structurally lower than those of coal fired units, so the latter can be shut down for longer periods of time given their slow and costly ramp rates.

Grid utlization [MVA / MVAmax] [%]								150/220 kV	380/450 kV
1	North Netherlands	NN	----->	2	Ring	RN		37%	65%
1	North Netherlands	NN	----->	5	Germany	DE			49%
1	North Netherlands	NN	<-----	7	Norway	NO			100%
2	Ring	RN	<-----	3	Maasvlakte	MV		0%	83%
2	Ring	RN	<-----	4	Zeeland	ZL		0%	83%
2	Ring	RN	----->	5	Germany	DE			78%
2	Ring	RN	<-----	6	Belgium	BE			1%
3	Maasvlakte	MV	<-----	8	United Kingdom	UK			100%
4	Zeeland	ZL	----->	6	Belgium	BE			91%

Figure 23: Scenario 2: Uncongested scheduled flows

Extent of congestion

As under the *Cheap natural gas* scenario no congestion would arise, the ECI-index returns a value of 0% indicating that 0% of the still available production capacity needs to be redispatched.

Congested zone	Constrained capacity	Initially non-dispatched capacity	ECI
North Netherlands	0.0	4559.4	0.00%
Ring		4298.1	
Maasvlakte		3300.0	
Zeeland		1224.0	
TOTALS		13381.5	

Table 45: Scenario 2: Extent of Congesion Index

Incentives

Because there is no congestion, no congestion management method is applied and no incentive is provided for any market player to change its behavior.

Market concentration

Table 46 shows the RSI values for both the Netherlands as a whole as well as for the node separately. Because no congestion arises in this situation, the value for the Netherlands as a whole applies. It shows that production capacities are sufficiently distributed among the different market players in order to prevent any of them from having market power.

Market concentration	Residual Supply Index (RSI)
Netherlands	154%

RSI per node		
1	NN	194%
2	RN	76%
3	MV	404%
4	ZL	370%

Table 46: Scenario 2: Market concentration per node

Table 47 presents an overview of the congestion costs that would arise under the different congestion management methods. As no congestion arose in this scenario and therefore none of these was applied, the only relevant information is provided by the column showing the market coupling benefits that are obtained from inter-node trade, when compared to the (hypothetical) situation where no power would be exchanged among the different congestion areas.

Congestion cost Scenario 2	BSR	MS	APX	MC	MC benefits
Consumers - NC zone - C zone	N/A	N/A	N/A	N/A	€ 186,618
Producers - NC zone - C zone	N/A	N/A	N/A	N/A	€ 90,835
TenneT - National - International	N/A	N/A	N/A	N/A	€ 8,093 € 42,760
National SW	**N/A**	**N/A**	**N/A**	**N/A**	**€ 285,547**
Foreign TSOs	N/A	N/A	N/A	N/A	€ 42,760
Total SW	**N/A**	**N/A**	**N/A**	**N/A**	**€ 328,307**

Table 47: Congestion cost distribution under scenario 2

H.3 Scenario 3: Green Revolution

Constructing several large-scale wind farms in the North Sea will not lead to congestion between the nodes defined in this study, as long as they are connected to node RN rather than MV. On the basis of existing construction permits for such production capacities, an overview of which was provided in (Noordzeeloket, 2009), this can be expected to be the case. The *Green Revolution* scenario that was run assumed all wind farms to feed into the grid at full capacity, which resulted in the grid utilization rates shown in Figure 24. Because wind power is offered to the market at very low marginal prices, this scenario will result in a net shift of production from the Maasvlakte to the Ring, thereby providing relief to the congested grid segment between MV and RN.

Grid utlization [MVA / MVAmax] [%]							150/220 kV	380/450 kV
1	North Netherlands	NN	---->	2	Ring	RN	31%	55%
1	North Netherlands	NN	---->	5	Germany	DE		7%
1	North Netherlands	NN	<-----	7	Norway	NO		100%
2	Ring	RN	<-----	3	Maasvlakte	MV	0%	58%
2	Ring	RN	<-----	4	Zeeland	ZL	0%	22%
2	Ring	RN	<-----	5	Germany	DE		14%
2	Ring	RN	---->	6	Belgium	BE		16%
3	Maasvlakte	MV	---->	8	United Kingdom	UK		100%
4	Zeeland	ZL	---->	6	Belgium	BE		56%

Figure 24: Scenario 3: Uncongested scheduled flows

Extent of congestion

As under the *Green Revolution* scenario no congestion would arise, the ECI-index returns a value of 0% indicating that 0% of the still available production capacity needs to be redispatched.

Congested zone	Constrained capacity	Initially non-dispatched capacity	ECI
North Netherlands	0.0	6992.0	0.00%
Ring		8466.2	
Maasvlakte		3072.0	
Zeeland		3504.0	
TOTALS		22034.2	

Table 48: Scenario 3: Extent of Congestion Index

Incentives

Because there is no congestion, no congestion management method is applied and no incentive is provided for any market player to change its behavior.

Market concentration

Under the *Green Revolution* scenario the market concentration in node RN decreases, because the scenario assumes several wind farms to be connected to this node. This additional production capacity increases the market concentration in node RN to near-competitive levels. Essent is the only producer left that would have market power if no trade were allowed among the nodes. However, as no congestion arises in this scenario, the RSI value for the Netherlands as a whole applies. This value has also increased compared to the base case scenario, to 182%, indicating that without the largest supplier there is sufficient capacity available to meet demand almost twice.

Market concentration	Residual Supply Index (RSI)
Netherlands	182%

RSI per node		
1	NN	238%
2	RN	98%
3	MV	445%
4	ZL	416%

Table 49: Scenario 3: Market concentration per node

Table 50 shows an overview of the congestion cost distribution for the different CM-methods. As no congestion management method was applied, it only shows figures on the benefits that could be obtained from coupling separate markets by comparing the market coupling benefits to the (hypothetical) situation in which no inter-node trade would exist.

Congestion cost Scenario 3	BSR	MS	APX	MC	MC benefits
Consumers - NC zone - C zone	N/A	N/A	N/A	N/A	€ 27,365
Producers - NC zone - C zone	N/A	N/A	N/A	N/A	€ 545,729
TenneT - National - International	N/A	N/A	N/A	N/A	€ 14,910 € 65,177
National SW	**N/A**	**N/A**	**N/A**	**N/A**	**€ 588,004**
Foreign TSOs	N/A	N/A	N/A	N/A	€ 65,177
Total SW	**N/A**	**N/A**	**N/A**	**N/A**	**€ 653,181**

Table 50: Congestion cost distribution under scenario 3

H.4 Scenario 4: Code Red

Cooling water restrictions that affect the available production capacities of power plants using surface water as a heat sink may pose a threat to power supply, but has a surprisingly low influence on transmission grid congestion. Under the *Code Red* scenario more than 3,000 MW of available capacity was removed from the RN and ZL nodes together and it was expected that this loss of capacity would need to be compensated by additional production in the Eemshaven and Maasvlakte. Although this was indeed the case, it turned out that only 59 MW would need to be redispatched from the Maasvlakte to the congested zone for the power flows not to exceed thermal limits – despite the fact that 6000 MW of exports to Belgium and Germany were assumed in this scenario as well.

Grid utlization [MVA / MVAmax] [%]								150/220 kV	380/450 kV
1	North Netherlands	NN	----->	2	Ring	RN		47%	84%
1	North Netherlands	NN	----->	5	Germany	DE			57%
1	North Netherlands	NN	<-----	7	Norway	NO			100%
2	Ring	RN	<-----	3	Maasvlakte	MV		0%	101%
2	Ring	RN	<-----	4	Zeeland	ZL		0%	68%
2	Ring	RN	----->	5	Germany	DE			74%
2	Ring	RN	----->	6	Belgium	BE			3%
3	Maasvlakte	MV	----->	8	United Kingdom	UK			100%
4	Zeeland	ZL	----->	6	Belgium	BE			83%

Figure 25: Scenario 4: Uncongested scheduled flows

Extent of Congestion

Because the congestion volume on the grid segment between MV and RN is only 59 MW, which is less than 1.5% of the available transmission capacity, it is not surprising that the ECI value is small as well. Less than 1% of the available production capacity in the downstream congested zone is required to solve congestion.

Congested zone	Constrained capacity	Initially non-dispatched capacity	ECI
North Netherlands Ring Zeeland	59.1	3963.9 3085.1 478.0	0.79%
TOTALS		7527.0	

Table 51: Scenario 4: Extent of Congestion Index

Reason for grid utilization pattern

The impact of issuing a code red situation seems rather small at first, with only 210 MW being needed to redispatch from the Maasvlakte congestion zone to other parts of the country. This is because relatively much capacity is already dispatched at the Maasvlakte under normal circumstances, as was discussed in H.1, which leads to redispatch capacities to be sought in other nodes.

Market concentration

Although the *Code Red* scenario includes a large decrease in available production capacity in the congested region, all but the largest producer (Nuon) would still be able to meet more than all demand. There is no single dominant player.

Market concentration	Residual Supply Index (RSI)
Netherlands	137%
Not-congested region	404%
Congested region	115%

Table 52: Scenario 4: Market concentration

H.4.1 Basic system redispatch

Market price	**€ 66.95**	
Coff price (range)	€ 66.95	(in € / MWh)
Con price (range)	€ 66.95	

	Surplus uncongested	Surplus congested	Surplus difference
Consumers	€ 2,799,139	€ 2,799,139	€ 0
- Not congested area	*€ 171,638*	*€ 171,638*	*€ 0*
- Congested area	*€ 2,627,501*	*€ 2,627,501*	*€ 0*
Producers	€ 391,776	€ 391,776	€ 0
- Not congested area	*€ 105,019*	*€ 105,019*	*€ 0*
- Congested area	*€ 286,757*	*€ 286,757*	*€ 0*
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l. trade)	€ 108,090	€ 108,090	€ 0
Total national SW	***€ 3,190,915***	***€ 3,190,915***	***€ 0***
TSOs foreign	€ 108,090	€ 108,090	€ 0
Total SW	***€ 3,190,915***	***€ 3,190,915***	***€ 0***

Table 53: Scenario 4: Congestion cost under basic system redispatch

As the congested volume is very small under the *Code Red* scenario (59 MW), the marginal cost of *constrained off* and compensatory *constrained on* production is equal to the MCP. This means that TenneT will be able to acquire *constrained on* power at a cost equal to *constrained off* revenues, which results in a net cost of zero.

Incentives

Consumers:	No incentives.
Producers:	No incentives.
TSO:	No incentives.

H.4.2 Market splitting

Market price	Optimal dispatch	Congestion	
Not-congested zone	€ 66.95	€ 66.95	(in € / MWh)
Congested zone	€ 66.95	€ 66.95	

Congestion cost – Market splitting	Surplus uncongested	Surplus congested	Surplus difference (congestion cost)
Consumers	€ 2,799,139	€ 2,799,139	€ 0
- Not congested zone	€ 171,638	€ 171,638	€ 0
- Congested zone	€ 2,627,501	€ 2,627,501	€ 0
Producers	€ 391,776	€ 391,776	€ 0
- Not congested zone	*€ 105,019*	*€ 105,019*	*€ 0*
- Congested zone	*€ 286,757*	*€ 286,757*	*€ 0*
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l.)	€ 108,090	€ 108,090	€ 0
Total national SW	***€ 3,299,004***	***€ 3,299,004***	***€ 0***
TSOs foreign	*€ 108,090*	*€ 108,090*	*€ 0*
Total SW	***€ 3,407,094***	***€ 3,407,094***	***€ 0***

Table 54: Scenario 4: Congestion cost under market splitting

The application of market splitting results in the creation of two congestion zones with the Maasvlakte being separated from the other nodes because its connection with the Ring has become congested. Interestingly enough, the MCP is not affected in any of the congestion zones. Apparently congestion can be solved by a redispatch of units which were offered to the market at equal marginal prices. The reason why market splitting still has an influence on congestion, despite the fact that is does not provide any price signal – which is the very essence of market splitting theoretically – is because it forces generators to produce electricity in a specific zone. All production capacity must be offered with locational recognition (i.e. one of the four nodes, assuming a system as used in the simulation model), but the market is first cleared without paying attention to the offers' locations. If the transaction pattern would result in congestion, the market operator uses the offer location recognition information to split the market and limit the amounts of power that can be produced in two or more congestion areas, if necessary.

Congestion costs

Because the MCP does not change anywhere after applying market splitting, consumers experience no difference from its application. For similar reasons the producer surplus difference is equal to zero as well, because units can be redispatched at equal marginal cost in the area downstream of the congestion. Note that this outcome provides an indication that producers offered electricity at competitive levels (i.e. at marginal cost). If capacity would have been offered above marginal cost, in an effort to manipulate the MCP and profit additionally, they would have been able to redispatch at lower cost and thereby experience a surplus gain equal to the difference between the height of the marginal offer and their actual cost of redispatch, multiplied by the redispatched volume. It is important to point out that such a finding would be difficult or even impossible to obtain in reality, as the actual cost of production is not precisely known to the TSO or market operator.

As a result of the equal price level, there is no benefit for the TSO from national market splitting. From international trade with Germany, Belgium, Norway, and the UK it still gains a benefit, as well as the TSOs in these countries.

Incentives

Consumers:	No incentives.
Producers:	No incentives.
TSO:	No incentives.

H.4.3 Market coupling

Market price	Uncoupled	Coupled	
North Netherlands	€ 61.52	€ 66.95	
Ring	€ 99.32	€ 66.95	
Maasvlakte	€ 44.00	€ 66.95	
Zeeland	€ 49.48	€ 66.95	
Germany	€ 91.80	€ 91.80	(in € / MWh)
Belgium	€ 91.80	€ 91.80	
Norway	€ 6.60	€ 6.60	
United Kingdom	€ 91.80	€ 91.80	

Congestion cost – Market coupling	Surplus uncoupled	Surplus coupled	*Coupling benefits*	Surplus under optimal dispatch	*Difference MC / OD*
Consumers	€ 2,235,163	€ 2,799,139	*€ 563,975*	€ 2,799,139	*€ 0*
Producers	€ 156,698	€ 391,776	*€ 235,078*	€ 391,776	*€ 0*
TSO (national)	€ 0	€ 0	*€ 0*	€ 0	*€ 0*
TSO (int'l.)	€ 0	€ 108,090	*€ 108,090*	€ 108,090	*€ 0*
Total national SW	***€ 2,391,861***	***€ 3,190,915***	***€ 799,054***	***€ 3,299,004***	***€ 0***
TSOs foreign	€ 0.00	€ 108,090	*€ 108,090*	€ 108,090	*€ 0*
Total SW	***€ 2,391,861***	***€ 3,299,004***	***€ 907,143***	***€ 3,407,094***	***€ 0***

Table 55: Scenario 4: Congestion cost under market coupling

Due to the small congested volume of 59 MW under the *Code Red* scenario, the application of market coupling has no influence on surpluses compared to optimal dispatch. One does notice, however, that the fact that the separate markets are coupled yields a benefit compared to a situation in which no trade would exist between the markets.

Incentives

Consumers:	No incentives.
Producers:	No incentives.
TSO:	No incentives.

Market concentration

Table 56 shows the RSI values if the market would be uncoupled. As large amounts of production capacity are unavailable in nodes RN and ZL the RSI values in these nodes decrease from the base case scenario. Especially node RN would experience market power, as even *with* the largest producer it could only meet 89% of demand, thus indicating that a physical shortage would occur of the node was not coupled to other markets. Note that the values in Table 52 should be regarded as indicative for the situation under this scenario, which separates between regions upstream and downstream of congestion.

Market concentration		**Residual Supply Index (RSI)**
Netherlands		137%
RSI per node		
1	NN	194%
2	RN	62%
3	MV	404%
4	ZL	293%

Table 56: Scenario 4: Market concentration per node

H.4.4 APX-based method

Market price		
Consumers	€ 66.95	
Generators not-congested zone	€ 66.95	(in € / MWh)
Generators congested zone	€ 66.95	

Congestion cost – APX-based	Surplus uncongested	Surplus congested	Surplus difference (congestion cost)
Consumers	€ 2,799,139	€ 2,799,139	€ 0
- Not congested area	*€ 171,638*	*€ 171,638*	*€ 0*
- Congested area	*€ 2,627,501*	*€ 2,627,501*	*€ 0*
Producers	€ 391,776	€ 391,776	€ 0
- Not congested area	*€ 105,019*	*€ 105,019*	*€ 0*
- Congested area	*€ 286,757*	*€ 286,757*	*€ 0*
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l. trade)	€ 108,090	€ 108,090	€ 0
Total national SW	***€ 3,190,915***	***€ 3,190,915***	***€ 0***
TSO (foreign)	€ 108,090	€ 108,090	€ 0
Total SW	***€ 3,299,004***	***€ 3,299,004***	***€ 0***

Table 57: Scenario 4: Congestion cost under the APX-based method

Similar to the application of basic system redispatch the marginal cost of the decreased and increased production volumes in the upstream and downstream congestion areas respectively is equal, resulting in a net cost of zero. Because both the down regulated and up regulated capacity yields no surplus for the generators – marginal costs of these volumes are equal to revenues – there is no transfer of wealth.

Incentives

Consumers:	No incentives.
Producers:	No incentives.
TSO:	No incentives.

H.4.5 Conclusions Code Red

Under the *Code Red* scenario only a small amount of congestion would occur (59 MW). No cost is involved, however, which is the case because there is sufficient capacity available within the congested area that can be redispatched at equal marginal cost as the *constrained off* capacity. Therefore, congestion costs remain zero for all parties regardless of the congestion management method used.

Congestion cost Scenario 4	BSR	MS	APX	MC	MC benefits
Consumers - NC zone - C zone	 € 0 € 0	 € 0 € 0	 € 0 € 0	€ 0	€ 563,975
Producers - NC zone - C zone	 € 0 € 0	 € 0 € 0	 € 0 € 0	€ 0	€ 235,078
TenneT - National - International	 € 0 € 0	 € 0 € 0	 € 0 € 0	 € 0 € 0	 € 0 € 108,090
National SW	**€ 0**	**€ 0**	**€ 0**	**€ 0**	**€ 799,054**
Foreign TSOs	€ 0	€ 0	€ 0	€ 0	€ 108,090
Total SW	**€ 0**	**€ 0**	**€ 0**	**€ 0**	**€ 907,143**

Table 58: Congestion cost distribution under scenario 4

Appendix I: Strategic bidding

Chapter 6 discussed the region congestion sensitivity, congestion cost, congestion cost distribution, resulting incentives, and market concentration on the basis of different scenarios and congestion management mechanisms. During the simulation runs that provided the scenario outcomes an important assumption was that producers of electricity offered their capacities at marginal cost. In reality, however, this may not be the case if producers can benefit from artificially altering the market clearing price or constrained off/on prices. In order to evaluate the consequences of such strategic behavior, a number of “business cases” were simulated in which one or more generators offer electricity to the market – spot, constrained off, or constrained on market – at prices below or above marginal cost with the intention to increase their profits. This enables TenneT to gain a quantitative insight in the financial consequences of such behavior if it were to take place.

Appendix I.1 discusses the types of strategic bidding that can be applied as a possible manner to increase profits, and Appendix I.2 describes the strategic bidding business cases that were simulated and the results thereof.

Disclaimer
All business case scenarios described in this chapter comprise hypothetical situations that *could* but not necessarily *would* occur in reality. The generators used for the purpose of the examples are determined on the basis of random choice, insofar as they match the specific company profile that was sought for a particular example. There is no reason to assume that the electricity producers whose strategic bidding opportunities were quantified by this study are any more, nor less, likely to exhibit such behavior in reality, compared to those whose strategic bidding behavior was not simulated.

I.1 Types of congestion management method gaming

The four different congestion management mechanisms that are considered in this study require different behavior from producers if trying to artificially increase revenues from their application.

I.1.1 Gaming basic system redispatch

Hers et al. (2009b) distinguishes two categories of market power abuse under the basic system redispatch method: strategic volume bidding and strategic price bidding, each of which can be applied in both the *constrained off* and *constrained on* markets. Under strategic volume bidding, a generator benefits by artificially creating, or increasing the extent of, congestion, which forces the TSO to apply congestion management or which increases the traded *constrained off* and *constrained on* volumes. With the use of strategic price bidding a generator aims to create a discrepancy between the true cost of production and the *constrained off* bids or *constrained on* offers, in order to benefit from the system without affecting the extent of congestion.

More specifically, a generator can pursue the following strategies:

- Offer less volume and be required to become constrained on – at high cost
- Offer constrained off capacity at a price lower than the actual avoided cost
- Submit the dispatch of expensive production capacity to the E-program, anticipating that this capacity will be constrained off

I.1.2 Gaming market splitting

Under market splitting there is no direct flow of monetary compensation from or to generators when congestion arises. Congestion is dealt with by fluctuating market prices which reflect the need for generators to produce electricity in a particular area. Given the inelastic demand, a generator can thus only benefit by artificially increasing the MCP which increases its profit margin on the power sold. Unlike basic system redispatch, the extent of congestion (i.e. the capacity that needs to be redispatched) has no influence on congestion payments in itself. It merely determines whether or not congestion zones are identified which need to be cleared separately, but the capacity that needs to be redispatched itself provides no possibilities for generators to increase congestion revenues. The congestion zones are simply cleared again, without “memory” of the reason why this is done.

The only way to increase revenues for a generator is to artificially adjust the MCP in a manner that is similar to “normal” uncongested market power. The MCP, which applies to all consumers and producers (within a congestion zone) is determined by the height of the marginal accepted offer. If a generator wants to increase its profits, it can only apply a strategy that aims to influence the market price in order to increase profit margins. The price, however, can be influenced by both volume-based and price-based strategies. These are described below. Note that these are 'generic' strategies that can be applied in electricity spot markets regardless of whether congestion arises.

Volume-based influence	Under strategic volume bidding a generator decreases the volume it offers, in an effort to get a more expensive marginal offer to set the market price. Unless this more expensive offer is also set by the same generator, this strategy comes at the cost of a smaller sold volume. For the strategy to be effective, the additional profit margin must outweigh the losses that result from the reduced volume sold. As the traded volume is not yet known at the time of the bidding processes, a generator must anticipate both the volume that will be traded in a given hour and the height of the offers around the market clearing point. It may do so on the basis of historic data, but runs the risk that the MCP eventually lies at a level that is lower than anticipated, which makes the strategy backfire.
Price-based influence	Strategic price bidding can only be applied if the generator's offer is the marginal accepted offer, which sets the MCP. By inflating the height of this offer a generator may increase its revenues, but it must ensure not to exceed the height of the next (not-accepted) offer, because if it offers capacity at a higher price it will price itself out of the market. Note that demand is considered inelastic in this study, but that the sold volume may decrease as a result of a higher MCP in reality. This needs to be taken into account by a generator as well.
Combination	A third strategy consists of a combination of both the former. By artificially decreasing the sold volume by offering a smaller volume a generator can shift the supply curve such that the market clearing point lies at a point where it can offer electricity at an inflated price itself.

Strategic bidding under congestion

In case of congestion the strategic bidding strategies described above can become more beneficial and/or easy to apply. Because the spot market liquidity in each congestion zone is smaller than in the zones combined by definition, a generator may have a lower (for the generator: better) RSI value in one of the zones, compared to an uncongested system.

Also, a generator that owns multiple units both inside and outside the congested zone may force a market split. If a generator knows that it has significant market power in one of the zones that result after the market split, it may create congestion (i.e. under optimal dispatch there would be no congestion) by offering some of its capacity in the not-congested area below variable cost, in order to create additional flows from this (upstream) area to the downstream area. This strategy would be profitable if the generator can create additional revenues in the congested area that outweigh the cost of offering capacity at a loss to force the split.

I.1.3 Gaming market coupling

The possibilities to exert market power under the market coupling mechanism is similar to those for market splitting. Instead of “forcing a market split” a generator forces markets to remain uncoupled.

I.1.4 Gaming the APX-based method

As was discussed in section 4.4.3, the APX-based method is similar to basic system redispatch in the sense that the most expensive units are constrained off, and compensatory power is acquired by dispatching the cheapest units still available. Unlike basic system redispatch, however, the APX-method implicitly auctions *constrained off* and *constrained on* capacity. Rather than organizing a separate market for these, the generators that must regulate down and regulate up respectively are determined directly by their initial market offers. Under the assumption of perfect competition this was found to yield the same outcome in terms of congestion cost distribution, because the offers rejected and accepted in second instance would be precisely those *constrained off* bids and *constrained on* offers that would be accepted under basic system redispatch.

The implicit nature of the APX-based method does have the implication that generators can no longer distinguish between 'normal' spot market offers and constraint-relief offers. Also, an important difference with basic system redispatch is that generators that are *constrained off* no longer receive any compensation and thus have no opportunities to bid strategically. However, the not-*constrained off* producers can decrease their congestion cost at the expense of the TSO by inflating the highest accepted marginal offer.

In short, the APX-based method does not provide the same possibilities for strategic bidding as basic system redispatch. Generators can increase their revenues both upstream and downstream from the :

- Decrease congestion cost for not-*constrained off* generators by inflating offers
- Increase congestion revenues by inflating offers that are expected to be accepted as compensatory *constrained on* power

I.2 Business cases

This section describes the business cases in which one or more producers aim to artificially increase their profits at the expense of consumers and/or the TSO. These business cases can be described as “what-if” analyses, in which a number of hypothetical cases of market power abuse are constructed and simulated: *“What are the consequences in terms of congestion cost (distribution) if this type of behavior was actually exerted?”*. All cases are tested under the conditions of the *Low wind availability in Germany* scenario, as the extent of congestion in this scenario (1292 MW) is most suited for such an analysis out of the four scenarios. In all business cases it is assumed that the congestion management method that the producers try to game has already been implemented for a sufficiently long period, which has given them the opportunity to learn from historic outcomes and to have all the information that they can possibly gain from experience.

I.2.1 Constrained off bids below true avoided cost under basic system redispatch

By bidding into the *constrained off* market at a price below the actual cost of production, a generator can increase its profits at the cost of the TSO. It must be careful, though, not to underbid other players because this would make the producer not constrained off. Under the *Low wind availability in Germany* scenario 1292 MW is constrained off, 1055 MW of which is “supplied” by Intergen at € 61.52 / MWh as is shown by Table 59. The remaining 237 MW is provided by Eneco at € 60.55 / MWh, and the other bids shown are not accepted because these are not required to solve the constraint. Neither Intergen nor Eneco make an additional *constrained off* profit in this situation, because the height of their offers reflect the actual costs of production.

Constrained off market					
Supplier	Volume	Bid	Volume (cum.)	Accepted?	Coff payment
	MW	€ / MW	MW (cum.)	MW	€
INTERGEN	234.7	€ 61.52	-234.7	-234.7	€ 14,438.03-
INTERGEN	820.0	€ 61.52	-1054.7	-820.0	€ 50,447.66-
ENECO	425.0	€ 60.55	-1479.7	-237.1	€ 14,355.01-
ENECO	425.0	€ 60.55	-1904.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-2429.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-2954.7	0.0	€ 0.00
E.ON BENELUX	1050.0	€ 44.00	-4004.7	0.0	€ 0.00
ELECTRABEL	800.0	€ 44.00	-4804.7	0.0	€ 0.00
Constrained on cost		€ 79,471.85-			
Net cost TenneT		€ 231.15-			

Table 59: Constrained off capacity under scenario 1 (perfect competition)

In this situation both Intergen and Eneco can bid strategically to increase their profits. Eneco can do so by decreasing the height of its bid to any level above the next expensive bid (which is E.ON, at € 49.48 / MWh). If Eneco bids at € 49.49, it is still constrained off because this would be the cheapest option for TenneT to solve the constraint. Instead of € 14,355.01, Eneco would then only have to pay € 11,733.60. This means a wealth transfer from TenneT to Eneco equal to € 2,621.41. A complete surplus difference overview is provided in Table 60.

Market price	**€ 61.52**	
Coff price (range)	€ 60.55 … € 61.52	(in € / MWh)
Con price (range)	€ 61.52	

Congestion cost – BSR	Surplus congested (no strategic bidding)	Surplus congested	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 273,248	€ 2,621
- Not congested area	*€ 67,360*	*€ 69,981*	*€ 2,621*
- Congested area	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 231-	€ 2,853-	€ 2,621-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,183,698***	***€ 0***
TSOs foreign	€ 113,068	€ 113,068	€ 0

Table 60: Distribution of congestion costs (strategic Coff bidding by Eneco under BSR)

Because Eneco's *constrained off* bids add up to 850 MW which is less than the total capacity that is required to be *constrained off*, there is also a possibility for Intergen to offer capacity at a lower price level and still be constrained off. Table 61 shows the situation when Intergen offers 1055 MW at € 49.49 / MWh and Eneco offers the capacities of both its units at € 60.55 / MWh. This situation would mean a wealth transfer of € 5,913.76 from TenneT to Intergen. A complete surplus difference overview is provided in Table 62.

Constrained off market					
Supplier	Volume	Bid	Volume (cum.)	Accepted?	Coff payment
	MW	€ / MW	MW (cum.)	MW	€
ENECO	425.0	€ 60.55	-425.0	-425.0	€ 25,732.30-
ENECO	425.0	€ 60.55	-850.0	-425.0	€ 25,732.30-
INTERGEN	820.0	€ 49.49	-1670.0	-441.8	€ 21,863.34-
INTERGEN	234.7	€ 49.49	-1904.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-2429.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-2954.7	0.0	€ 0.00
E.ON BENELUX	1050.0	€ 44.00	-4004.7	0.0	€ 0.00
ELECTRABEL	800.0	€ 44.00	-4804.7	0.0	€ 0.00
Constrained on cost		€ 79,471.85-			
Net cost TenneT		€ 6,143.91-			

Table 61: Constrained off bids under scenario 1 (strategic price bidding)

Market price	**€ 61.52**	
Coff price (range)	€ 60.55 … € 61.52	(in € / MWh)
Con price (range)	€ 61.52	

Congestion cost – BSR	Surplus congested (no strategic bidding)	Surplus congested (strategic bidding)	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 276,540	€ 5,913
- Not congested area	*€ 67,360*	*€ 73,273*	*€ 5,913*
- Congested area	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 231-	€ 6,144-	€ 5,913-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,183,698***	***€ 0***
TSOs foreign	€ 113,068	€ 113,068	€ 0

Table 62: Distribution of congestion costs (strategic Coff bidding by Intergen under BSR)

Strategic price bidding limits

The figures of € 2,621.41 and € 5,913.76 calculated above indicate the maximum wealth transfers that individual producers can create by strategic price bidding in the constrained off market under the *Low wind availability in Germany* scenario, on the basis of the marginal cost estimates that lie at the basis of this study. In reality, Intergen and Eneco could also *both* bid strategically, which would have the consequence that TenneT receives only € 49.49 / MWh for all of the constrained capacity (1292 MW). However, Hers et al. (2009b) argue that there is a floor below which bid reductions will not go undetected by the regulator, which they estimate to be somewhere around 10% or 20% below actual cost of production. Given the current scenario conditions, an artificial bid reduction of 10% (see Table 63) would still impose a *constrained off* cost of € 8,155.22 for TenneT, which on a yearly basis would add up more than € 70 mln. if these scenario conditions would be present the whole year round. An overview of the surplus differences in this case can be found in Table 64.

Constrained off market					
Supplier	Volume	Bid	Volume (cum.)	Accepted?	Coff payment
	MW	€ / MW	MW (cum.)	MW	€
INTERGEN	234.7	€ 55.37	-234.7	-234.7	€ 12,994.23-
INTERGEN	820.0	€ 55.37	-1054.7	-820.0	€ 45,402.89-
ENECO	425.0	€ 54.49	-1479.7	-237.1	€ 12,919.51-
ENECO	425.0	€ 54.49	-1904.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 44.53	-2429.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 44.53	-2954.7	0.0	€ 0.00
E.ON BENELUX	1050.0	€ 39.60	-4004.7	0.0	€ 0.00
ELECTRABEL	800.0	€ 39.60	-4804.7	0.0	€ 0.00
Constrained on cost		€ 79,471.85-			
Net cost TenneT		€ 8,155.22-			

Table 63: Constrained off bids under scenario 1 (assuming an artificial 10% reduction)

Congestion cost – BSR	Surplus congested (no strategic bidding)	Surplus congested (strategic bidding)	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 278,551	€ 7,924
- Not congested area	*€ 67,360*	*€ 75,284*	*€ 7,924*
- Congested area	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 231-	€ 8,155-	€ 7,924-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,183,698***	***€ 0***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,767***	***€ 3,296,767***	***€ 0***

Table 64: Surpluses under strategic constrained off bidding (BSR / scenario 1)

I.2.2 Scheduling inefficient capacity under basic system redispatch

A generator that has economically inefficient production capacity available that would be too expensive to run under normal circumstances, can be used to benefit from congestion under the basic system redispatch congestion management scheme (Hakvoort et al., 2009). Table 65 shows the generators that still have capacity available in the area upstream of congestion. They have units available that do not run (or do not run at full capacity) under the *Low wind availability in Germany* scenario, because they produce at or above MCP:

Generator	**Available capacity**	**Variable cost**
INTERGEN	193	€ 61.52
E.ON BENELUX	250	€ 61.52
ENECO	246	€ 66.95
E.ON BENELUX	78	€ 66.95
C.GEN	400	€ 76.53

Table 65: Overview of not-dispatched upstream production units under scenario 1

All of these producers have production capacity available in the downstream area. This section will demonstrate what happens in the hypothetical situation that C.GEN anticipates a similar situation as shown in the previous example, Table 59, and seeks to enlarge its surplus. Besides the 400 MW unit shown in Table 65, C.GEN has an 800 MW production unit in the downstream area.

The initial market outcome is similar to the competitive situation, with C.GEN and all other producers offering their capacities at competitive levels. This includes C.GEN offering 800 MW at a price level of € 44.00, which reflects the marginal production cost of its other unit. When the E-program for the respective hour is submitted, the company notifies TenneT that it wishes to produce 400 MW using its unit at the Maasvlakte and 400 MW using its unit in Zeeland. This results in a production shift of 400 MW from the downstream to the upstream area, which increases the extent of congestion: 1692 MW now needs to be redispatched from the upstream to the downstream area. C.GEN places a bid in the *constrained off* market for 400 MW at € 60.56 / MWh (just above the expected bid by Eneco) and a *constrained on* offer for 400 MW at MCP, which is € 61.52 / MWh. This is shown in Table 66.[72]

Constrained off market

Supplier	Volume MW	Bid € / MW	Volume (cum.) MW (cum.)	Accepted? MW	Coff payment €
INTERGEN	234.7	€ 61.52	-234.7	-234.7	€ 14,438.03-
INTERGEN	820.0	€ 61.52	-1054.7	-820.0	€ 50,447.66-
C.GEN	400.0	€ 60.56	-1454.7	-400.0	€ 24,224.00-
ENECO	425.0	€ 60.55	-1879.7	-237.2	€ 14,363.08-
ENECO	425.0	€ 60.55	-2304.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-2829.7	0.0	€ 0.00
E.ON BENELUX	525.0	€ 49.48	-3354.7	0.0	€ 0.00
E.ON BENELUX	1050.0	€ 44.00	-4404.7	0.0	€ 0.00
ELECTRABEL	800.0	€ 44.00	-5204.7	0.0	€ 0.00

Constrained on market

Supplier	Volume MW	Offer € / MW	Volume (cum.) MW (cum.)	Accepted? MW	Producer revenue €
ESSENT	426	€ 61.52	426	426	€ 26,208.17
C.GEN	400	€ 61.52	826	400	€ 24,608.00
Eemsmond Energie B.V.	400	€ 61.52	1226	400	€ 24,608.61
Eemsmond Energie B.V.	400	€ 61.52	1626	400	€ 24,608.61
Eemsmond Energie B.V.	400	€ 61.52	2026	65.9	€ 4,054.65
DELESTO B.V.	195	€ 61.52	2221	0	€ 0.00
ESSENT	150	€ 61.52	2371	0	€ 0.00
NAM B.V.	130	€ 61.52	2501	0	€ 0.00

<the remaining, more expensive and not accepted offers are not shown in this table>

Table 66: Constrained off and constrained on bids, under deliberate inefficient unit scheduling

In this situation there would be a transfer of wealth from TenneT to C.GEN which is equal to € 384, compared to the situation in which no market power is exerted when applying basic system redispatch under these scenario conditions. The additional cost arises because the volume traded in the *constrained off* and *constrained on* markets is increased by 400 MW, with a discrepancy between the *constrained off* and *constrained on* price levels ((€ 60.56 and € 61.52, respectively). This difference, multiplied by the volume of 400 MW, must be borne by TenneT.

Note that the dispatch of units in this situation is exactly the same as it would be under perfect competition, but that C.GEN nevertheless benefits from bidding strategically in the constraint markets. Essentially, what caused the difference is that C.GEN now managed to get paid by the TenneT for dispatching units as efficiently as possible – which, of course, it would have done anyway. If the constraint markets would rely upon individual negotiation sessions between each market player and TenneT, C.GEN basically entered the negotiations by "bluffing" that it could achieve optimal dispatch by dispatching its unit in MV, but that it could switch to sub-optimal dispatch if it would be compensated for this. Because this switch would in fact not raise dispatching costs for C.GEN, the compensation that it negotiated with TenneT would be pure profit.

72 Note that some constrained on capacity is not accepted despite being offered at exactly the same price level as the accepted offers. In reality there would need to be a procedure that specifies how to deal with such a situation. It does not have any influence on the current example, however, because here it is assumed that all other producers offer capacity at marginal cost which would mean that both those that are accepted and those that are not accepted have a surplus that is exactly zero.

Table 67 shows the allocation of congestion costs among all stakeholders. One observes that net social welfare remains equal, which means that no surplus was lost on the whole. This can be explained by what was already discussed above: the final unit dispatch pattern did not change from the pattern under competitive and optimal dispatch. However, C.GEN did manage to get paid for dispatching efficiently in the process.

Market price	**€ 61.52**	
Coff price (range)	€ 60.55 … € 61.52	(in € / MWh)
Con price (range)	€ 61.52	

Congestion cost – BSR	Surplus congested (no strategic bidding)	Surplus congested (strategic bidding)	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 271,011	€ 384
- Not congested area	*€ 67,361*	*€ 67,744*	*€ 384*
- Congested area	*€ 203,266*	*€ 203,266*	*€ 0*
TSO (national)	€ 231-	€ 615-	€ 384-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,183,698***	***€ 0***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,767***	***€ 3,296,766***	***€ 0***

Table 67: Surpluses under deliberate inefficient scheduling by C.GEN

I.2.3 Deliberate withholding of capacity to become constrained on under BSR

Generators can also make a profit by withholding capacity from the 'regular' market, in order to have capacity available to offer in the *constrained on* market. This strategy is profitable if a generator manages to become *constrained on* and receives a higher price than MCP. It is important that the generator withholds capacity from the regular market, because if it must dispatch all capacity to fulfill its supply obligations there is no capacity left to offer in the *constrained on* market. This section will demonstrate the hypothetical situation in which Electrabel initially withholds 1493 MW from the market, with the aim to offer this capacity in the *constrained on* market and receive a price which is higher than MCP (€ 61.52 / MWh).

The withdrawal of supply in the congested area first results in an increase in congestion: 1485 MW must now be redispatched from the upstream to the downstream area to solve congestion. Table 68 shows the situation in the *constrained off* and *constrained on* markets. The strategic *constrained on* offers by Electrabel are shown in purple.

In the *constrained off* market the only change is that the volume slightly increases. Because generators here bid competitively at avoided cost, they do not gain additional revenue. In the *constrained on* market, however, Electrabel has offered a 1493 MW at € 66.94, an offer which maximizes its revenues while still being accepted (i.e. cheaper than the next offers). All other offers (including the other offers made by Electrabel) are at competitive levels. Table 69 shows the congestion cost distribution and compares these with the situation in which there is no strategic bidding. Producer surplus has increased slightly, but the additional congestion costs for the TSO have risen more than ten-fold. Also, social welfare has gone down by € 1,952. Surplus has not only been transferred from the TSO to the producers, but has also been lost in the process: apparently, dispatch is less than optimal. This is caused by Electrabel's withholding of capacity in the market: 1493 MW of demand must now be met by more expensive producers.

Constrained off market					
Supplier	Volume	Bid	Volume (cum.)	Accepted?	Coff payment
	MW	€ / MW	MW (cum.)	MW	€
INTERGEN	820	61.52153366	-820	-820	€ 50,447.66-
INTERGEN	428	61.52153366	-1248	-428	€ 26,331.22-
ENECO	425	60.54659241	-1673	-237.0902925	€ 14,355.01-
ENECO	425	60.54659241	-2098	0	€ 0.00
E.ON BENELU	525	49.4796033	-2623	0	€ 0.00
E.ON BENELU	525	49.4796033	-3148	0	€ 0.00
E.ON BENELU	1050	44.00400287	-4198	0	€ 0.00
ELECTRABEL	800	44.00400287	-4998	0	€ 0.00

Constrained on market					
Supplier	Volume	Offer	Volume (cum.)	Accepted?	Producer revenue
	MW	€ / MW	MW (cum.)	MW	€
Eemsmond Er	326.3174123	€ 61.52	326.3	326.3	€ 20,075.55
DELESTO B.V	195	€ 61.52	521.3	195.0	€ 11,996.70
ESSENT	150	€ 61.52	671.3	150.0	€ 9,228.23
NAM B.V.	130	€ 61.52	801.3	130.0	€ 7,997.80
EMMTEC	60	€ 61.52	861.3	60.0	€ 3,691.29
MILL WK MA/	60	€ 61.52	921.3	60.0	€ 3,691.29
MINNEWIT B.	60	€ 61.52	981.3	60.0	€ 3,691.29
ELECTRABEL	593	€ 66.94	1574.3	503.8	€ 33,722.56
ELECTRABEL	450	€ 66.94	2024.3	0.0	€ 0.00
ELECTRABEL	450	€ 66.94	2474.3	0.0	€ 0.00
Elsta B.V. & C	460	€ 66.95	2934.3	0.0	€ 0.00
DELESTO B.V	360	€ 66.95	3294.3	0.0	€ 0.00
ELECTRABEL	352	€ 66.95	3646.3	0.0	€ 0.00
ELECTRABEL	352	€ 66.95	3998.3	0.0	€ 0.00
ELECTRABEL	350	€ 66.95	4348.3	0.0	€ 0.00
ELECTRABEL	349	€ 66.95	4697.3	0.0	€ 0.00
ELECTRABEL	346	€ 66.95	5043.3	0.0	€ 0.00
ESSENT	306	€ 66.95	5349.3	0.0	€ 0.00
ESSENT	241.5	€ 66.95	5590.8	0.0	€ 0.00
<the remaining, more expensive and not accepted offers are not shown in this table>					

Table 68: Constrained markets under strategic constrained on bidding by Electrabel

Market price	**€ 61.52**	
Coff price (range)	€ 60.55 … € 61.52	(in € / MWh)
Con price (range)	€ 61.52 … € 66.94	

Congestion cost – BSR	Surplus without stretegic bidding	Surplus with strategic bidding	Surplus difference
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested area	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 271,405	€ 778
- Not congested area	*€ 67,360*	*€ 67,360*	*€ 0*
- Congested area	*€ 203,267*	*€ 204,045*	*€ 778*
TSO (national)	€ 231-	€ 2,961-	€ 2,730-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,181,746***	***€ 1,952-***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,767***	***€ 3,294,815***	***€ 1,952-***

Table 69: Congestion cost distribution assuming strategic constrained on bidding by Electrabel

Profits from strategic bidding

By bidding strategically, Electrabel gets paid € 33,722.56 (€ 66.94 / MWh) to dispatch 503.8 MW in the congested area. Because it can do so at the cost of only € 49.48 / MWh, the company increases its profits by € 8,796.08. However, because its sold volume is also down as a result of its initial capacity withholding, Electrabel also loses the profits it could have made if it had sold the withheld 1493 MW in the regular market at MCP (€ 61.52 / MWh). Table 70, which presents a clear overview of these figures, shows that although the sold volume is down from 1493 MW to 503.8 MW, Electrabel still profits from the increased profit margin. It increases its total revenue by € 778, but, as Table 69 already showed, increases social costs by almost three times this amount in the process.

Strategic bidding revenues Electrabel	
Constrained on revenues (503.8 MW at € 66.94)	€ 33,722.56
Constrained on dispatch (503.8 MW at € 49.48)	€ 24,926.48-
Lost market revenues (1493 MW at € 61.52)	€ 91,851.65-
Avoided dispatch costs by initial withholding - 593 MW at € 49.48 - 900 MW at € 60.55	 € 29,341.40 € 54,491.93
Total revenues from bidding strategically	**€ 777.76**

Table 70: Revenues from strategic bidding (Electrabel)

I.2.4 Price inflation under market splitting

As was discussed in Appendix I.1, neither generators nor consumers are compensated for the consequences of congestion under the market splitting mechanism: every market player is simply subject to the prevailing market price in their congestion zone. A generator can thus only benefit from congestion additionally if it manages to artificially inflate the market price in a location in which it has production capacity available. To be able to do so a generator needs to either set the MCP by being the marginally accepted offer in a market in which the next offer is higher (otherwise the generator would price itself out of the market by offering at a higher price), or by having relatively much production capacity in place, so it can artificially decrease supply in order to shift the MCP to a level that is sufficiently higher in order for additional revenues to outweigh the loss in sold volume.

This section shows what would happen if Essent, which although not being dominant in the definition of RSI (130%) is the largest producer in the congested area (nodes NN, RN, and ZL), would deliberately withhold 2140 MW of capacity from the market. This is done by not offering the capacity of two gas fired units located in node RN, with available capacities of 1300 MW and 840 MW.

Market price	Optimal dispatch	Congestion	
Not-congested zone	€ 61.52	€ 60.55	(in € / MWh)
Congested zone	€ 61.52	€ 66.95	

Congestion cost – Market splitting	Surplus uncongested (no strat. bidding)	Surplus uncongested (strat. bidding)	Strategic bidding revenues (no congestion)
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested zone	*€ 178,638*	*€ 178,638*	*€ 0*
- Congested zone	*€ 2,734,664*	*€ 2,734,664*	*€ 0*
Producers	€ 270,627	€ 270,627	€ 0
- Not congested zone	*€ 67,360*	*€ 67,360*	*€ 0*
- Congested zone	*€ 203,267*	*€ 203,267*	*€ 0*
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l.)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,296,998***	***€ 3,296,998***	***€ 0***
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,410,066***	***€ 3,410,066***	***€ 0***

Table 71: Strategic bidding revenues under market splitting, without congestion

If no transmission limits would apply, the strategic bidding action would not have any influence to social welfare, as is shown by Table 71. Essent would not lose any surplus, though, because the units it deliberately took off the market would have produced at exactly the MCP, which would have resulted in a surplus of zero (also see Table 73).

In the congested situation, on the other hand, the strategic volume bidding actions of Essent raise MCP in the congestion area from € 61.52 / MWh to € 66.95 / MWh. The consequences for social welfare are shown by Table 72. Consumers in the area downstream of congestion see their electricity price increase and face the largest loss of surplus, whereas generators in this area experience an increase of surplus for the same reason. Essent increases its profits by more than twelve thousand Euros as a result of bidding strategically, which is shown in Table 73.

Note that not only Essent itself benefits from strategic bidding, and that it in fact only enjoys slightly over 10% of the total additional generator revenues that are generated by its (sole) actions.

Market price	Optimal dispatch	Congestion	
Not-congested zone	€ 61.52	€ 60.55	(in € / MWh)
Congested zone	€ 61.52	€ 66.95	

Congestion cost – Market splitting	Surplus congested (no strat. Bidding)	Surplus congested (strat. bidding)	Strategic bidding revenues
Consumers	€ 2,914,560	€ 2,807,397	€ 107,163-
- Not congested zone	€ 179,896	€ 179,896	€ 0
- Congested zone	€ 2,734,664	€ 2,627,501	€ 107,163-
Producers	€ 265,321	€ 369,306	€ 103,984
- Not congested zone	*€ 62,054*	*€ 62,054*	*€ 0*
- Congested zone	*€ 203,267*	*€ 307,251*	*€ 103,984*
TSO (national)	€ 4,792	€ 31,461	€ 26,670
TSO (int'l.)	€ 112,093	€ 83,333	€ 28,761-
Total national SW	***€ 3,296,767***	***€ 3,291,496***	***€ 5,270-***
TSOs foreign	€ 113,068	€ 113,068	*€ 0*
Total SW	***€ 3,409,835***	***€ 3,404,565***	***€ 5,270-***

Table 72: Strategic bidding revenues under market splitting, with congestion

Strategic bidding revenues	Uncongested		Congested	
	No strategic bidding	Strategic bidding	No strategic bidding	Strategic bidding
Revenues	€ 232,797.48	€ 127,349.57	€ 259,005.66	€ 158,666.98
Dispatch cost	€ 218,588.01	€ 113,140.10	€ 244,796.18	€ 132,410.54
Profit	**€ 14,209.47**	**€ 14,209.48**	**€ 14,209.48**	**€ 26,256.44**
Additional revenues from strategic bidding	*€ 0.00*		*€ 12,046.96*	

Table 73: Strategic bidding revenues for Essent (market splitting)

TenneT

An interesting situation arises when comparing the TSO surplus differences in the situation where Essent and the other generators benefit from strategic bidding by Essent. Table 72 shows that TenneT's internal congestion rents are up € 26,670, but that it loses € 28,761 in international trade compared to the competitive situation. The internal revenues are up as a result of a larger price difference between the uncongested and congested areas, which allows TenneT to receive a larger congestion rent. Also with respect to trade with Norway the congestion rent TenneT receives is increased. However, at the same time it generates smaller revenues from trade with Germany and Belgium, while it must also compensate the decreased congestion rents for the TSOs in those countries. The strategic bidding of Essent therefore leads to TenneT's net congestion benefits to shrink from € 3,817 (€ 4,792 [internal] minus € 975 [int'l.]; see Table 40 on page 151) to € 1,726. The remaining social welfare loss is borne by consumers in the area downstream from congestion.

I.2.5 Capacity withholding and offer inflation under the APX-based method

Generators can no longer gain additional revenues for being *constrained off*, since this capacity is no longer compensated under the APX-based method. In order to increase profits under this method generators have two objectives:

1. Set the marginal accepted offer in the upstream area (after removing the *constrained off* capacity) as high as possible, and
2. In the downstream congestion area: offer a volume equal to the expected *constrained on*

volume at a price higher than MCP, but sufficiently low to be accepted.

It is also possible for generators that only have capacity available in one of the congestion zones to benefit from congestion by using one of these strategies. However, if a generator owns production capacity in both zones (which is accepted under the prevailing MCP), it may have to pursue both of these strategies in order for revenues in one zone not to be transformed into congestion costs in the other. This effect is similar to the strategy to strategically bid under the *system redispatch with cost pass-through to generators* method described by Hakvoort et al. (2009) and depends on the share of a generator in *constrained on* and *constrained off* power.

This section will demonstrate what the consequences are if Electrabel, which is the only producer that has significant (competitive) capacities in both the upstream and the downstream area, expects to be (able to become) *constrained on* in the downstream area and wants to increase its revenues, and seeks to mitigate the resulting cost in the upstream area.

Electrabel has two production units running at a variable cost (€ 60.55 / MWh) just below MCP (€ 61.52 / MWh). Its profit margin is therefore small, which makes these units perfect for strategic withholding under the current market conditions. Because the company expects to be constrained on, it offers the capacity of one of its units in the downstream area – which can produce at a variable cost of € 49.48 / MWh – at € 66.94 / MWh. To reduce the loss of surplus in the upstream area, Electrabel offers its 800 MW unit there at a price level of € 61.51, which is just one cent below the next offer. The market transaction pattern results in congestion, and 1909 MW needs to be redispatched. The offers for the upstream and downstream area are shown in tables 74 and 75 respectively, with the strategic bids by Electrabel indicated in purple.

Supply (upstream)						
Supplier	Volume	Offer €/MW	Volume (cum.) MW	Accepted? 5204.709708	Generator revenue	TSO "revenue"
	Highest accepted offer:		0			
WIND ONSHC	61.8	€ 10.00	61.8	61.8	€ 3,801.32	€ 0.71
AVR	45	€ 31.90	106.8	45	€ 2,767.95	€ 0.52
AVR	60	€ 31.90	166.8	60	€ 3,690.60	€ 0.69
WASTE < 60 I	65	€ 31.90	231.8	65	€ 3,998.15	€ 0.75
E.ON BENELU	1050	€ 44.00	1281.8	1050	€ 64,585.50	€ 12.11
E.ON BENELU	525	€ 49.48	1806.8	525	€ 32,292.75	€ 6.06
E.ON BENELU	525	€ 49.48	2331.8	525	€ 32,292.75	€ 6.06
WKK < 60 MV	1435	€ 52.44	3766.8	1435	€ 88,266.85	€ 16.55
E.ON BENELU	25	€ 52.44	3791.8	25	€ 1,537.75	€ 0.29
ENECO	425	€ 60.55	4216.8	425	€ 26,141.75	€ 4.90
ENECO	425	€ 60.55	4641.8	425	€ 26,141.75	€ 4.90
ELECTRABEL	800	€ 61.51	5441.8	562.9	€ 34,624.58	€ 6.49
INTERGEN	820	€ 61.52	6261.8	0	€ 0.00	€ 0.00
<the remaining, more expensive and not accepted offers are not shown in this table>						

Table 74: Strategic bidding under the APX-method (upstream supply offers)

Supply (downstream)

Supplier	Volume	Offer €/MW	Volume (cum.) MW	Accepted? 20133.2	Price paid to generator	Generator revenue	TSO cost
<the cheaper accepted offers are not shown>							
Akzo Nobel In	84	€ 57.73	11584.5	84	€ 61.52	€ 5,167.81	€ 0.00
SCA	60	€ 57.73	11644.5	60	€ 61.52	€ 3,691.29	€ 0.00
NUON	450	€ 60.55	12094.5	450	€ 61.52	€ 27,684.69	€ 0.00
ELECTRABEL	0	€ 60.55	12094.5	0	€ 61.52	€ 0.00	€ 0.00
ELECTRABEL	0	€ 60.55	12094.5	0	€ 61.52	€ 0.00	€ 0.00
ESSENT	1300	€ 61.52	13394.5	1300	€ 61.52	€ 79,977.99	€ 0.00
INTERGEN	900	€ 61.52	14294.5	900	€ 61.52	€ 55,369.38	€ 0.00
ESSENT	840	€ 61.52	15134.5	840	€ 61.52	€ 51,678.09	€ 0.00
ESSENT	464	€ 61.52	15598.5	464	€ 61.52	€ 28,545.99	€ 0.00
NUON	450	€ 61.52	16048.5	450	€ 61.52	€ 27,684.69	€ 0.00
Sloecentrale E	435	€ 61.52	16483.5	435	€ 61.52	€ 26,761.87	€ 0.00
Sloecentrale E	435	€ 61.52	16918.5	435	€ 61.52	€ 26,761.87	€ 0.00
DELTA	430	€ 61.52	17348.5	430	€ 61.52	€ 26,454.26	€ 0.00
ESSENT	426	€ 61.52	17774.5	426	€ 61.52	€ 26,208.17	€ 0.00
Eemsmond Er	400	€ 61.52	18174.5	400	€ 61.52	€ 24,608.61	€ 0.00
Eemsmond Er	400	€ 61.52	18574.5	400	€ 61.52	€ 24,608.61	€ 0.00
Eemsmond Er	400	€ 61.52	18974.5	400	€ 61.52	€ 24,608.61	€ 0.00
DELESTO B.\	195	€ 61.52	19169.5	195	€ 61.52	€ 11,996.70	€ 0.00
ESSENT	150	€ 61.52	19319.5	150	€ 61.52	€ 9,228.23	€ 0.00
NAM B.V.	130	€ 61.52	19449.5	130	€ 61.52	€ 7,997.80	€ 0.00
EMMTEC	60	€ 61.52	19509.5	60	€ 61.52	€ 3,691.29	€ 0.00
MILL WK MA/	60	€ 61.52	19569.5	60	€ 61.52	€ 3,691.29	€ 0.00
MINNEWIT B.	60	€ 61.52	19629.5	60	€ 61.52	€ 3,691.29	€ 0.00
ELECTRABEL	593	€ 66.94	20222.5	503.8	€ 66.94	€ 33,722.56	€ 2,729.68-
Elsta B.V. & C	460	€ 66.95	20682.5	0	€ 66.95	€ 0.00	€ 0.00
DELESTO B.\	360	€ 66.95	21042.5	0	€ 66.95	€ 0.00	€ 0.00
ELECTRABEL	352	€ 66.95	21394.5	0	€ 66.95	€ 0.00	€ 0.00
ELECTRABEL	352	€ 66.95	21746.5	0	€ 66.95	€ 0.00	€ 0.00
ELECTRABEL	350	€ 66.95	22096.5	0	€ 66.95	€ 0.00	€ 0.00
ELECTRABEL	349	€ 66.95	22445.5	0	€ 66.95	€ 0.00	€ 0.00
ELECTRABEL	346	€ 66.95	22791.5	0	€ 66.95	€ 0.00	€ 0.00
ESSENT	306	€ 66.95	23097.5	0	€ 66.95	€ 0.00	€ 0.00
<the remaining, more expensive and not accepted offers are not shown in this table>							

Table 75: Strategic bidding under the APX-based method (downstream supply offers)

Table 74 shows that Electrabel sets the price that is received by all generators in the upstream area, because it is the highest accepted offer. If Electrabel would have offered competitively at € 44.00 / MWh in the area upstream of congestion, the marginal accepted offer would have been set by Eneco at € 60.55. In that situation TenneT would have been able to transfer the *constrained on* cost of € 2,729.68 (as shown by Table 75) to the generators in the upstream area. This would have resulted in a cost of € 0.524 / MWh (€ 2,729.68 spread out over 5204.7 MWh of accepted offers), and as such would have lowered the price paid to generators in the upstream area to € 60.986 / MWh. Electrabel's strategic bid thus resulted in the price paid to generators to be kept at the near MCP-level of € 61.51.

Market price		
Consumers	€ 61.52	(in € / MWh)
Generators not-congested zone	€ 61.51	
Generators congested zone	€ 61.52 … € 66.94	

Congestion cost – APX-based	Surplus congested (no strategic bidding)	Surplus congested (strategic bidding)	Strategic bidding revenues
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	€ 0
- Congested area	*€ 2,734,664*	*€ 2,734,664*	€ 0
Producers	€ 270,396	€ 267,191	€ 3,204-
- Not congested area	*€ 67,129*	*€ 63,146*	€ 3,982-
- Congested area	*€ 203,267*	*€ 204,045*	€ 778
TSO (national)	€ 0	€ 2,670-	€ 2,670-
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,177,824***	**€ 5,874-**
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,767***	***€ 3,290,893***	**€ 5,874-**

Table 76: Surplus distribution with and without strategic bidding (APX-method / scenario 1)

Table 76 presents the surplus differences that result from Electrabel's strategic bidding behavior. For comparison, the strategic bidding surplus difference for the (hypothetical) unconstrained system (i.e. no transmission limits) is shown in Table 77 as well.

Strategic bidding by Electrabel results in a net loss of welfare. This is the consequence of sub-optimal dispatch, which is caused by 900 MW of (competitive) production capacity owned by Electrabel being deliberately withheld in the downstream area (Table 75), and Electrabel's 800 MW unit in the upstream area not being fully used (Table 74). Instead of the 900 MW units in the downstream area that could produce just below MCP, units that produce <u>at</u> MCP must now be dispatched. In the upstream area 800 – 562.9 = 237.1 MW is produced by units that produce only slightly below MCP, rather than much below it.

Market price		
Consumers	€ 61.52	
Generators not-congested zone	€ 61.52	(in € / MWh)
Generators congested zone	€ 61.52	

Congestion cost – APX-based	Surplus uncongested (no strategic bidding)	Surplus uncongested (strategic bidding)	Strategic bidding revenues
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	€ 0
- Congested area	*€ 2,734,664*	*€ 2,734,664*	€ 0
Producers	€ 270,627	€ 262,609	€ 8,018-
- Not congested area	*€ 67,360*	*€ 67,360*	€ 0
- Congested area	*€ 203,267*	*€ 195,249*	€ 8,018-
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,929***	***€ 3,175,911***	**€ 8,018-**
TSOs foreign	€ 113,068	€ 113,068	€ 0
Total SW	***€ 3,296,998***	***€ 3,288,979***	**€ 8,018-**

Table 77: Surplus distribution with and without strategic bidding (Uncongested / scenario 1)

Strategic bidding revenues for Electrabel

Electrabel itself experiences additional revenue in the *constrained on* area from the higher price received, but loses revenue in both the *constrained on* and *constrained off* areas due to the smaller volumes it sells. As is shown by Table 78, Electrabel experiences a net loss as a result of its strategic bidding, primarily because its surplus in the upstream area is down as a result of its effort to mitigate the transfer of congestion costs by TenneT (shown in the third row – the volume is down from 800 MW to 562.9 MW, because Electrabel sets the marginal offer which is not completely accepted).

Strategic bidding		No strategic bidding	
Revenue (downstream) € 66.54 * 503.8 MW Production cost (downstream) € 49.48 * 503.8 MW	 € 33,722.56 € 24,770.28-	Revenues (downstream) € 61.52 * 900 MW € 61.52 * 593 MW Production cost (downstream) € 60.55 * 900 MW € 49.48 * 593 MW	 € 55,369.38 € 36,482.27 € 54,491.93- € 29,341.40-
Revenue (upstream) € 61.51 * 562.9 MW Production cost (upstream) € 44.00 * 562.9 MW	 € 34,624.58 € 24,926.48-	Revenues (upstream) € 61.52 * 800 MW Production cost (upstream) € 44.00 * 800 MW	 € 49,217.23 € 35,203.20-
	€ 18,650.38		€ 22,032.35
Additional revenues	**€ 3,381.97-**		

Table 78: Revenues and losses from strategic bidding by Electrabel

If Electrabel applies the same strategy, but without the effort to mitigate congestion costs in the upstream area, it will benefit from strategic bidding as is shown by Table 79. This would create the societal surplus differences as shown in Table 80. TenneT manages to transfer its *constrained on* costs to the generators upstream of congestion, which because of this get a slightly lower price (€ 61.00) than MCP (€ 61.52) and see their total surplus shrink with € 2,730. In the constrained on area additional producer surplus is created only by Electrabel, which manages to get a *constrained on* price above MCP. Surplus is also lost, however, because instead of Electrabel's slightly-below-MCP-production-cost units (€ 60.52), other units which produce at exactly MCP must be dispatched. This results in no additional costs for these producers, but does create the societal welfare loss which is transferred to the upstream generators as discussed before.

Strategic bidding		No strategic bidding	
Revenue (downstream) € 66.54 * 503.8 MW Production cost (downstream) € 49.48 * 503.8 MW	 € 33,722.56 € 24,770.28-	Revenues (downstream) € 61.52 * 900 MW € 61.52 * 593 MW Production cost (downstream) € 60.55 * 900 MW € 49.48 * 593 MW	 € 55,369.38 € 36,482.27 € 54,491.93- € 29,341.40-
Revenue (upstream) € 61.00 * 800 MW Production cost (upstream) € 44.00 * 800 MW	 € 48,797.66 € 24,926.48-	Revenues (upstream) € 61.52 * 800 MW Production cost (upstream) € 44.00 * 800 MW	 € 49,217.23 € 35,203.20-
	€ 32,823.46		€ 22,032.35
Additional revenues	**€ 10,791.11**		

Table 79: Strategic bidding revenues Electrabel (no strategic bids in upstream area)

Market price		
Consumers	€ 61.52	(in € / MWh)
Generators not-congested zone	€ 61.00	
Generators congested zone	€ 61.52 … € 66.94	

Congestion cost – APX-based	Surplus congested (no strategic bidding)	Surplus congested (strategic bidding)	Strategic bidding revenues
Consumers	€ 2,913,302	€ 2,913,302	€ 0
- Not congested area	*€ 178,638*	*€ 178,638*	€ 0
- Congested area	*€ 2,734,664*	*€ 2,734,664*	€ 0
Producers	€ 270,396	€ 268,444	€ 1,952-
- Not congested area	*€ 67,129*	*€ 64,399*	€ 2,730-
- Congested area	*€ 203,267*	*€ 204,045*	€ 778
TSO (national)	€ 0	€ 0	€ 0
TSO (int'l. trade)	€ 113,068	€ 113,068	€ 0
Total national SW	***€ 3,183,698***	***€ 3,181,746***	**€ 1,952-**
TSOs foreign	€ 113,068	€ 113,068	€ 0

Table 80: Congestion cost distribution under strategic constrained on bidding by Electrabel

Summarizing, one can conclude that the APX-based method can be gamed by producers in order to increase their welfare. However, this does not create any additional costs for TenneT, because it is able to transfer these to the upstream generators completely. In fact, in this situation TenneT would only need to use half of its “room to maneuver” (which can be defined as the difference between MCP and the highest accepted marginal offer in the upstream area, which is € 60.55 ↔ € 61.52) and could transfer additional *constrained on* costs to these generators up to the point that the price they receive is down to € 60.55 from the current € 61.00. Given that approximately the next 3200 MW of constrained on power is offered at more or less the same price as TenneT pays now (€ 66.95 vs € 66.94 per MWh), the amount of congestion could be doubled (i.e. requiring an additional 1909 MW of *constrained on* power) before TenneT would experience any cost at all. The APX-based method is therefore a relatively safe option for TenneT, as it is likely to be able to transfer all congestion costs to generators in reality.

Appendix J: Application of the ARGUS method

This appendix presents the application of the ARGUS method. In order to understand the steps that were taken, the reader must possess at least some basic knowledge of the ARGUS method, see e.g. Pruyt (2009). For the results that were obtained at the end of this analysis, please refer to section 8.2.4.

J.1 Ordinal scores

This section explains the ordinal scores that were assigned to the congestion management methods for the different criteria, as also shown in Table 13 in section 8.2.2.

Criteria	**BSR**	**MS**	**MC**	**APX**
Short-term efficiency	++	++	++	++
Attractiveness of renewables	++	=	-	++
Proportionality	+	-	-	+
Facilitate existing production	+	--	--	-
Discourage new excess capacity	--	++	++	=
Vulnerability strategic bidding	--	+	+	=
Efficient transmission signals	++	-	-	=
Compliance institutional f.'work	++	=	=	+
Non-discrimination	+	+	+	+
Simplicity and transparency	+	+	+	+
Influence without congestion	=	=	=	=

Table 81: Qualitative scores of congestion management methods

Short-term efficiency (least-cost dispatch under congestion constraints)

All methods result in the same short-term efficiency, measured by congestion costs (€ 231 / hr), as was found and presented in Chapter 6. The units that are dispatched after application of a congestion management methods are the same under all methods and are the least-cost dispatch.

Attractiveness for renewable energy investments

Under the basic system redispatch and APX-based methods renewable energy sources can be excluded from participating in the scheme. Market splitting and market coupling do not allow for this, although the generators with renewable production capacity could be compensated financially if they experience a disadvantage. Market splitting scores slightly better than market coupling because the method clears the market as a whole first, which could provide reference for such compensation.

Proportionality

Basic system redispatch and the APX-based method allocate the cost of congestion to a (type of) stakeholder directly, whereas market splitting and market coupling create both large benefits as well as large costs.

Facilitate existing production in areas with excess capacity

Under market splitting, market coupling, and the APX-based methods existing producers face the consequences of congestion. If they are located in an area upstream of congestion, their profits will decrease as a result of a lower MCP (under MS/MC) or allocation of *constrained on* costs (under APX). Because the APX-based method affects these generators less, it scores better than MS/MC.

BSR does not affect existing producers, although it does not achieve the highest score possible because these generators still need to participate in the *constrained off* market and are as such not left completely unaffected.

Discourage new units from being constructed in areas with excess capacity

The lower MCP in areas with excess capacity under market splitting and market coupling lead to smaller revenues under congestion when there already is excess capacity in an area. Basic system redispatch does not affect generator revenues and therefore does not discourage new units from being constructed in areas with excess capacity at all. The APX-based method only affects generators to the extent that compensatory power comes at a higher cost, and thus scores between MS/MC on the one hand, and BSR on the other.

Vulnerability to strategic bidding

Basic system redispatch creates an additional opportunity for generators to abuse the scheme because it makes use of a constrained off market, which can be used by generators to be compensated . Market splitting and market coupling only provide strategic bidding opportunities also available in the normal market. The APX-based method does not compensate *constrained off* generators and therefore scores better than BSR, but it is more vulnerable than market splitting and market coupling because, unlike these which will simply drive down the MCP as far as necessary (thus forcing generators to withdraw from the market once MCP drops below their variable cost), the APX-based method provides opportunities for generators to limit the costs they need to bear, while still being able to sell their electricity in the market.

Signaling efficient level of transmission investments

Under basic system redispatch the TSO must, in principle, bear all costs of congestion and therefore provides the best incentives for transmission investments when necessary. Market splitting and market coupling, on the other hand, create a benefit for the TSO benefits under congestion and thereby do not create an incentive. Because it is possible for the competition authority to lay down that all congestion rents must be invested in the transmission system, these methods do not get the worst possible score. The APX-based method scores neutral and in between the other methods, because it only provides an incentive if it can no longer transfer (all) costs to generators in the constrained off area.

Compliance with institutional framework

All methods fit in the legal framework governing the electricity sector, but only basic system redispatch fits directly into institutional framework governing market processes without influencing the underlying processes (e.g. bilateral long-term contracts). The APX-based method requires all generators to bid into a centralized spot market, although it allows other contracts to be carried out as well. Market splitting and market coupling have far-reaching consequences as they require all generators to bid into a mandatory spot market, at least with respect to intra-nodal trade.

Non-discrimination

None of the methods discriminates between existing and new producers.

Simplicity and transparency

All methods make use of simple and transparent procedures

Influence without congestion

All methods have a neutral influence when there is no congestion.

J.2 Inter-criteria importance structure

Table 82 shows the degrees of importance that were assigned to the different criteria. These importances are set to be consistent with Hakvoort et al. (2009), insofar they played a role during that study. The criteria that were not included or need additional explanation are discussed below.

Degrees of importance
Not important
Little important
Moderately important
Very important
Extremely important

Criteria	Importance
Short-term efficiency	Extremely important
Attractiveness of renewables	Extremely important
Proportionality	Very important
Facilitate existing production	Little important
Discourage new excess capacity	Very important
Vulnerability strategic bidding	Very important
Efficient transmission signals	Little important
Compliance institutional framework	Moderately important
Non-discrimination	Very important
Simplicity and transparency	Little important
Influence when no congestion	Very important

Table 82: Degrees of criteria importance

Facilitate existing production

This objective was found by this study (see section 8.1.1). It was assigned little importance, in line with the importance assignment for the similar criterion "Incentives for decommissioning" by Hakvoort et al. (2009).

Discourage new excess production

This criterion is closely related to "Economic efficiency" as included by (Hakvoort et al., 2009), and is therefore assigned the same importance.

Efficient transmission signals

The Ministry regards congestion management primarily as a temporary measure that is applied until transmission reinforcements are complete. Congestion management should be applied for a period as short as possible and therefore it is an important criterion. However, De Vries & Hakvoort (2002) argue that it is more important to provide market parties with the right incentives for efficient long-term behavior, because "it is probably easier to influence the network planning process, as it is part of a regulated monopoly, than the investment decisions of generation companies" (p. 26). The importance of this criterion was rated down to 'little important', because transmission signals can also be influenced using other instruments than just by allocating congestion costs in a particular manner.

Compliance institutional framework

Unlike Hakvoort et al. (2009), this study does not solely evaluate congestion management methods for short-term application. Changing the institutional framework is therefore considered possible and it is not very important that the methods fit into the existing rules and processes in the electricity system.

Influence when there is no congestion

To prevent unnecessary limitations from being imposed to market transactions, Knops et al. (2001) argue that congestion management methods should not influence the market if there is no congestion that needs to be alleviated. In order to be able to consider the Netherlands as a copper plate as much as possible, the market transactions carried out by individual market players should be constrained as little as possible. Because the congestion sensitivity of all regions was found to be low (see Table 6 on page 49), there will be relatively many periods without congestion. It is thus very important that the congestion management method does not have (too much) influence on the electricity market when there is no congestion, because it would affect the system rather often given these findings. Therefore, the criterion is valued as 'very important'.

J.3 Intra-criterion preference structure

The intra-criterion preference structure determines whether and to what extent there is a preference for congestion management method x *(CM_x)* over CM_y with respect to criterion A *(c_A)*, given a difference in their ordinal score (see Table 13 on page 79). There may be reasons to use a different structure for each criterion, but because determining the precise structures would comprise a study of its own, the intra-criterion preference structure is considered to be the same for all criteria. It is shown in Table 83 and uses a similar measurement scale as in Pruyt (2009).

$c_A(CM_x)$ $c_A(CM_y)$	--	-	=	+	++
--	indifferent	/	/	/	/
-	small preference	indifferent	/	/	/
=	moderate pref.	small preference	indifferent	/	/
+	strong preference	moderate pref.	small preference	indifferent	/
++	very strong pref.	strong preference	moderate pref.	small preference	indifferent

Table 83: Intra-criterion preference structure

J.4 Combined inter- and intra-criteria structure

This study assumes the same combined inter- and intra-criteria preference structure as originally used by De Keyser & Peeters (1994) and provided by Pruyt (2009).

Classes:	(degree of preference, degree of importance) couples:
1	(very strong preference, extremely important)
2	(very strong preference, very important), (strong preference, extremely important)
3	(very strong preference, moderately important), (strong preference, very important), (moderate preference, extremely important)
4	(very strong preference, little important), (strong preference, moderately important), (moderate preference, very important), (small preference, extremely important)
5	(very strong preference, not important), (strong preference, little important), (moderate preference, moderately important), (small preference, very important)
6	(strong preference, not important), (moderate preference, little important), (small preference, moderately important)
7	(moderate preference, not important), (small preference, little important)
8	(small preference, not important)

Table 84: Combined inter- and intra-criteria structure (source: Pruyt, 2009)

J.5 Combined Preferences with Weights

The *Combined Preferences with Weights* (CPW) calculation is used to actually compare two methods with each other on all the criteria, which enables one to determine the outranking relationships among the methods. Because all methods must be compared pairwise, six CPW calculations were performed. The preference score ranking classes are used as in proposed by De Keyser & Peeters (1994) are used for the CPW calculations (see Table 85 and Table 86).

	criterion → preference ↓	not important	little important	moderately important	very important	extremely important
$f_j(s_k) > f_j(s_l)$	very strong	h_{11}	h_{12}	h_{13}	h_{14}	h_{15}
	strong	h_{21}	h_{22}	h_{23}	h_{24}	h_{25}
	moderate	h_{31}	h_{32}	h_{33}	h_{34}	h_{35}
	small	h_{41}	h_{42}	h_{43}	h_{44}	h_{45}
$f_j(s_k) = f_j(s_l)$	no	h_{51}	h_{52}	h_{53}	h_{54}	h_{55}
$f_j(s_k) < f_j(s_l)$	small	h_{61}	h_{62}	h_{63}	h_{64}	h_{65}
	moderate	h_{71}	h_{72}	h_{73}	h_{74}	h_{75}
	strong	h_{81}	h_{82}	h_{83}	h_{84}	h_{85}
	very strong	h_{91}	h_{92}	h_{93}	h_{94}	h_{95}

Table 85: CPW score table (source: De Keyser & Peeters (1994), in Pruyt (2009))

ϱ	$CPW(f_j(s_k) > f_j(s_k))$	$CPW(f_j(s_k) < f_j(s_k))$
1	$g_1^{(s_k,s_l)} = h_{15}$	$q_1^{(s_k,s_l)} = h_{95}$
2	$g_2^{(s_k,s_l)} = h_{14} + h_{25}$	$q_2^{(s_k,s_l)} = h_{85} + h_{94}$
3	$g_3^{(s_k,s_l)} = h_{13} + h_{24} + h_{35}$	$q_3^{(s_k,s_l)} = h_{75} + h_{84} + h_{93}$
4	$g_4^{(s_k,s_l)} = h_{12} + h_{23} + h_{34} + h_{45}$	$q_4^{(s_k,s_l)} = h_{65} + h_{74} + h_{83} + h_{92}$
5	$g_5^{(s_k,s_l)} = h_{11} + h_{22} + h_{33} + h_{44}$	$q_5^{(s_k,s_l)} = h_{64} + h_{73} + h_{82} + h_{91}$
6	$g_6^{(s_k,s_l)} = h_{21} + h_{32} + h_{43}$	$q_6^{(s_k,s_l)} = h_{63} + h_{72} + h_{81}$
7	$g_7^{(s_k,s_l)} = h_{31} + h_{42}$	$q_7^{(s_k,s_l)} = h_{62} + h_{71}$
8	$g_8^{(s_k,s_l)} = h_{41}$	$q_8^{(s_k,s_l)} = h_{61}$

Table 86: CPW calculation (source: De Keyser & Peeters (1994), in Pruyt (2009))

Pairwise CPW calculation tables

The remainder of this section contains the six *Combined Preferences with Weights* calculation tables that were used to compare all congestion management methods in a pairwise manner. The scores used follow from the qualitative ordinal assessment of congestion management methods as presented in section 8.2.2 (Table 13 on page 79) using the importance data from Table 14.

1. Basic system redispatch – Market splitting

	criterion → preference ↓	not important	little important	moderately important	very important	extremely important
BSR > MS	very strong					
	strong		2			
	moderate			1	1	1
	small					
BSR = MS	no		1		2	1
BSR < MS	small					
	moderate					
	strong				1	
	very strong				1	

	CPW (BSR > MS)	*CPW (BSR < MS)*
1	0	0
2	0	1
3	1	1
4	1	0
5	3	0
6	0	0
7	0	0
8	0	0

2. Basic system redispatch – Market coupling

	criterion → **preference ↓**	not important	little important	moderately important	very important	extremely important
BSR > MC	very strong					
	strong		2			1
	moderate			1	1	
	small					
BSR = MC	no		1		2	1
BSR < MC	small					
	moderate					
	strong				1	
	very strong				1	

	CPW (BSR > MC)	*CPW (BSR < MC)*
1	0	0
2	1	1
3	0	1
4	1	0
5	3	0
6	0	0
7	0	0
8	0	0

3. Basic system redispatch – APX-based method

	criterion → **preference ↓**	not important	little important	moderately important	very important	extremely important
BSR > APX	very strong					
	strong					
	moderate		2			
	small			1		
BSR = APX	no		1		3	2
BSR < APX	small					
	moderate				2	
	strong					
	very strong					

	CPW (BSR > APX)	*CPW (BSR < APX)*
1	0	0
2	0	0
3	0	0
4	0	2
5	0	0
6	3	0
7	0	0
8	0	0

4. Market splitting – Market coupling

	criterion → **preference ↓**	not important	little important	moderately important	very important	extremely important
MS > MC	very strong					
	strong					
	moderate					
	small					1
MS = MC	no		3	1	5	1
MS < MC	small					
	moderate					
	strong					
	very strong					

	CPW (MS > MC)	*CPW (MS < MC)*
1	0	0
2	0	0
3	0	0
4	1	0
5	0	0
6	0	0
7	0	0
8	0	0

5. Market splitting – APX-based method

	criterion → **preference ↓**	not important	little important	moderately important	very important	extremely important
MS > APX	very strong					
	strong					
	moderate				1	
	small				1	
MS = APX	no		1		2	1
MS < APX	small		2	1		
	moderate				1	1
	strong					
	very strong					

	CPW (MS > APX)	*CPW (MS < APX)*
1	0	0
2	0	0
3	0	1
4	1	1
5	1	0
6	0	1
7	0	2
8	0	0

6. Market coupling – APX-based method

	criterion → **preference ↓**	not important	little important	moderately important	very important	extremely important
MC > APX	very strong					
	strong					
	moderate				1	
	small				1	
MC = APX	no		1		2	1
MC < APX	small		2	1		
	moderate				1	
	strong					1
	very strong					

	CPW (MC > APX)	*CPW (MC < APX)*
1	0	0
2	0	1
3	0	0
4	1	1
5	1	0
6	0	1
7	0	2
8	0	0

J.6 Outranking relations

On the basis of the CPW calculations in the previous section, pairwise outranking relations were determined as indicated in Figure 26. Please refer to section 8.2.4 for a discussion of these.

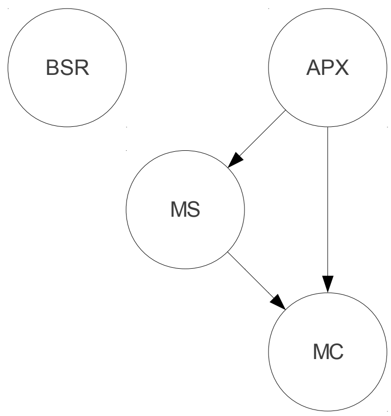


Figure 26: Method outranking relations (ARGUS)

Appendix K: Personal communications

Throughout this research project information was retrieved not only from literature sources, but from experts in the field as well. The communications that were used in this report as a reference, because they lie at the basis of essential statements and/or were used to construct scientific arguments, were documented for the purpose of allowing for their verification. This appendix provides brief transcripts of the relevant elements of these personal communications.

K.1 Gert van der Lee – November 3, 2010

Institution:	TenneT TSO B.V.
Participants:	Gert van der Lee
Main discussion topic:	Determine research topic
Location:	TenneT Headquarters, Arnhem

The foreseen expansion of production capacity (7 GW in total), with another 23 GW planned, is expected to lead to congestion in the Netherlands. TenneT expects congestion to arise with large volumes of scheduled transports being imposed on the grid on a structural basis. During this meeting, Gert van der Lee discussed the current knowledge gap that existed with respect to the consequences that could be expected from applying congestion management in the Netherlands, in particular with respect to the costs that TenneT could expect to arise. TenneT would be required to bear these. Also, he indicated that TenneT would like to gain a better insight in the requirements that the market will impose on the transmission infrastructure, in order to determine which transmission expansion projects should primarily be focused on.

K.2 Gert van der Lee – December 1, 2010

Institution:	TenneT TSO B.V.
Participants:	Gert van der Lee
Main discussion topic:	Causes and expected consequences of congestion in the Netherlands
Location:	TenneT Headquarters, Arnhem

This meeting was held during the proposal-phase of the project (which ran from December 1 until December 22, 2010) and was primarily focused on expanding the author's knowledge on the process that had taken place with respect to congestion management so far, as well as to further narrow down the research topic. Gert van der Lee discussed that various congestion management methods had been considered by the Ministry of Economic Affairs and TenneT, which eventually led to the decision to implement basic system redispatch. Also, he explicitly mentioned that the Ministry had rejected any scheme which passes on congestion costs to generators, because this was considered as running against European legislation.

The Minister of Economic Affairs considers congestion management to be a temporary measure which can be applied for the period TenneT requires to complete the required transmission expansions. TenneT, however, expects congestion in the Netherlands to have a more structural nature, because of the financial and planning difficulties that are expected with these grid expansion projects. Also, Gert van der Lee indicated that the competition authority has required TenneT to write off parts of the grid in an accelerated pace. This creates an additional financial burden for the company which will have an influence on its possibilities to finance grid expansions in the coming years.

Some key topics of interest with respect to the current research project were discussed at the end of this meeting. TenneT is interested in the congestion costs it can expect from basic system redispatch in the next 5 to 7 years and how these costs are allocated. For application in the longer term it would like research to be focused on expanding the knowledge on the functioning of congestion management methods that are currently being applied in Europe. Most importantly it is interested in the cost distributive effects and possibilities for gaming.

K.3 Gert van der Lee – December 6, 2010

Institution:	TenneT TSO B.V.
Participants:	Gert van der Lee
Main discussion topic:	Discussion of first set of research questions, to narrow down the research scope
Location:	TenneT Headquarters, Arnhem

The main goal of this meeting was to discuss the first set of research questions with the intention to narrow down the research scope. Additionally, the difficulties obtaining sufficient financial means for the required grid investments were discussed in more detail.

Gert van der Lee indicated that TenneT usually attracts between 30% and 70% of its funds for grid investments from the capital markets. The company has experienced difficulties in attracting this capital as a result of the credit crunch, however, and expects the situation to get worse as a result of the competition authority's decision that TenneT must write off its older assets in an accelerated pace. This requirement creates a negative image of the company in the financial markets and increases the regulatory component of the risk as assessed by lenders. Although no data is available on the percentage of the capital TenneT requires but will not be able to raise as a result of this, it expects this to be significant because of the large capital requirements the company will have in the (near) future.

K.4 Laurens de Vries – December 10, 2010

Institution:	Delft University of Technology
Participants:	Laurens de Vries (Assistant Professor)
Main discussion topic:	Research proposal
Location:	Delft University of Technology, Faculty of Technology, Policy & Management

This meeting was held during the proposal-phase of the project (which ran from December 1 until December 22, 2010) and was primarily focused on finding a suitable research approach.

Laurens de Vries elaborated (inter alia) on one of the differences in the regulatory approaches in Europe (specifically: the Netherlands) and the United States with respect to the information and authority a system operator possesses. In the PJM (Pennsylvania-New Jersey-Maryland) transmission system, a plant can be designated as a 'must run' plant, which can be forced to run by an ISO if this is necessary to solve congestion, at a predetermined cost. The ISO knows the marginal costs of these plants (or has detailed estimates) and can thus make such decisions without the need for producers to bid in a congestion power pool of some kind.

The advantage of this approach is that market power cannot be abused in an instance of congestion, unlike the system redispatch method, which will be applied in the Netherlands, because the producer does not have the opportunity to bid its constrained-off or constrained-on power to a congestion pool at excessive prices. However, as the ISO needs to estimate these figures somehow, a producer can still exert market power during the determination of these figures. A principal-agent relation exists between the producer and the ISO, with the former having more information on the actual costs of operation (and an incentive to project these higher than in reality) than the latter. In the Netherlands the function of competition authority NMa is to regulate ex post. When it suspects that market power has been abused an investigation can be opened and generators can be penalized if found guilty.

K.5 Klaas Hommes et al. – January 12, 2011

Institution:	TenneT TSO B.V.
Participants:	Klaas Hommes Rutger van Houtert Gert van der Lee
Main discussion topic:	Project progression and contents
Location:	TenneT Headquarters, Arnhem

During this meeting the following was discussed:

- Structure of the simulation model (see Figure 5 on page 33) was discussed and found to fit the study's purpose
- Congestion region borders: determining these should be part of the study's scope
- Inclusion of 110 kV and 220 kV grid, in addition to 380 kV, if applicable
- Klaas Hommes, Rutger van Houtert, and Gert van der Lee presented some ideas for the type of scenarios that would be particularly relevant for TenneT. These scenarios formed the basis for the scenarios that were eventually constructed (see Chapter 5).
    - Export scenario (e.g. 2000 – 6000 MW exports)
    - (Very) low natural gas prices
    - Large-scale introduction of offshore wind capacity
    - Code red