

Applying basic system redispatch for managing congestion in the Dutch transmission grid

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Abstract

Due to the foreseen expansion in production capacity, in combination with a new connection policy under which new entrants are directly connected to the grid, without having to wait for the required network reinforcements to be complete, transmission system operator TenneT expects congestion to arise on the Dutch transmission grid. To solve congestion, the Ministry of Economic Affairs has decided to implement basic system redispatch, a method which is argued in existing literature to potentially impose large congestion costs upon the TSO. A quantitative model of the Dutch electricity system was developed in order to gain a quantitative insight in the effects that the application of basic system redispatch will have when applied in the the specific Dutch (market) situation. The outcomes were compared to the performance of three market-based congestion management mechanisms. Congestion costs were found to be surprisingly low under all methods, but large differences exist in their distribution, which creates a difference in the incentives that are provided for long-term behavior. The provision of these incentives, which merely focus on transmission system efficiency, could have negative consequences with respect to overall societal objectives. Furthermore, the article discusses how regulatory provisions may create incentives for TSOs to invest in the grid when this is not efficient, and how to solve this problem.

Keywords: Congestion management, basic system redispatch, electricity, social welfare, the Netherlands, transmission system, TSO

1. Introduction

Several market players are currently planning, or already constructing, new generation units in the Netherlands. The foreseen expansion of production capacity, i.e. new generation capacity minus announced plants for decommissioning, equals 7 GW (van der Lee, 2010a). New production units are primarily concentrated at two coastal locations, the Maasvlakte and Eemshaven industrial areas, which are located at a distance from load areas (Derksen & van Houtert, 2011). As a result, the additional electricity produced in these areas will need to be transported to load areas, which imposes additional loads on the transmission infrastructure.

Under the new connection policy that was recently adopted by the Ministry of Economic Affairs¹, Dutch

transmission system operator TenneT is obliged to connect all new entrants to the transmission grid, regardless of whether sufficient transmission capacity is available. In the past, access for market parties could be delayed by TenneT if grid capacity was found to be insufficient, until the necessary reinforcements were implemented or until capacity became available due to other reasons, such as the decommissioning of old plants. The Minister of Economic Affairs found this practice to be discriminatory towards new entrants and preferred a system under which market players would be allowed direct access to the grid, without having to wait for capacity to become available (NMa, 2009, Article 34).

Due to this new connection policy, the Dutch TSO expects congestion to arise in the transmission grid in the near future. Congestion is defined, in line with definitions used throughout existing 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

¹ As of September 2010 the Ministry of Economic Affairs is integrated into the (new) Ministry of Economic Affairs, Agriculture, and Innovation. Its tasks and responsibilities with respect to energy-related issues remain unchanged.

deliveries (transactions) ... cannot be physically implemented as requested" (Lesieutre & Eto, 2004, p. 59). This situation can arise because producers and consumers are free to trade electricity in the liberalized Dutch electricity market, without having to take transmission capacity limitations into account. The units they schedule for dispatch, as the underlying product of their market transactions, may lead to a scheduled power flow pattern which would overload grid elements when physically implemented. The technical objective of congestion management is to rearrange these flows such that grid constraints, as well as market transactions, are adhered to.

In the Netherlands, the Ministry decided that the basic system redispatch method should be used to alleviate congestion when it arises. Under this method, which will be more extensively discussed in the next section, the TSO is responsible for alleviating congestion by contracting generators to increase and decrease their production levels such that the resulting power flow pattern is brought back within limits. However, this method is argued to potentially create excessive congestion costs, which are allocated to the TSO, and that it is particularly vulnerable to the abuse of generator market power (Hakvoort et al., 2009). A quantitative insight in the extent of these consequences is, however, still lacking.

The objective of this article is to quantify the effects of applying basic system redispatch in the Netherlands on the basis of a quantitative model, and to compare these effects to those that would result from applying other congestion management methods. Section 2 will introduce the basic system redispatch method and discuss the underlying reasons that led to its implementation. Section 3 will briefly introduce the most important literature on the topic of congestion management. In particular, it will discuss the current European trend towards market-based methods that was identified and discuss which methods will be evaluated during this study. The model itself is introduced in Section 4. Section 5 discusses the key performance indicators that were used to assess the congestion management methods using the quantitative model, while the results that were obtained by its application are presented in Section 6. Section 7 discusses the knowledge and new insights that were obtained on the basis of these quantitative simulation results.

2. Basic system redispatch

This section discusses the characteristics of basic system redispatch (section 2.1; on the basis of Hakvoort et al., 2009) as well as the reasoning behind the decision to implement it in the Netherlands (section 2.2).

2.1. Characteristics

Alleviating congestion is the responsibility of the TSO under basic system redispatch. In order to successfully alleviate congestion, it must ensure that sufficient power

is redispatched from the area upstream² of congestion, to the area downstream of congestion, i.e. the area which was supposed to consume the excess power produced in the upstream area, but now needs to regulate up capacity to compensate for the power that could not be physically delivered. This is done by organizing two markets, a *constrained off* and a *constrained on* market, in which generators place bids and offers for being regulated down and regulated up, respectively.

The mechanism of basic system redispatch is only applied when congestion would arise on the basis of the scheduled flows under regular market conditions. If this is the case, basic system redispatch is meant to adjust these flows and bring them back within transmission limits. It does thus not intervene in regular market processes and alleviates congestion on the background. Knops et al. (2001) categorize this type of method as a *corrective method*.

Under basic system redispatch, constrained off generators are still credited for their intended production. They can sell the same volume as originally contracted by their customers, regardless of the type of contract used in this transaction. However, since their plants do not need to run, they save their variable costs. On the basis of this notion, Hakvoort et al. (2009) argue that a constrained off generator is thus willing to pay the TSO an amount of money up to the level of its avoided production costs. This would make them better off than having to actually produce. Basically, the generator pays for the transfer of its production obligations to the TSO, which will accept the bids of those generators that are willing to pay most, i.e. have the highest variable costs (assuming that generators bid according to their true variable cost), first.

In the downstream area, the TSO must now acquire sufficient power to compensate for constrained off production, in order to fulfill the production obligations it has taken over. This is done in the constrained on market, in which generators that are located in the area downstream of congestion that still have capacity available (i.e. which was not sold in the regular market) can offer compensatory power. Here, the TSO accepts the cheapest offers, all of which receive a payment according to a pay-as-bid structure.

Congestion costs arise because the acquisition of constrained on power (by the TSO) is more expensive than the height of the constrained off payments. These costs are borne by the TSO, which provides it with an incentive to expand transmission capacity in order to avoid them in the future.

2.2. Decision

Anticipating an increase of congestion on the Dutch transmission grid as a result of its new connection policy

² The area upstream of congestion is the area which has excess capacity scheduled for production, which cannot (all) be physically transported. As a consequence, some of this capacity may not be physically implemented.

and the foreseen expansion of production capacity, led the Ministry of Economic Affairs to investigate possible measures to deal with this congestion. It commissioned D-Cision and The Brattle Group (Hakvoort et al., 2009) to analyze the congestion management options available for the Netherlands. One requirement from the Ministry was that the method should be implementable on the short term, which limited the methods that were considered by this study to those that could be implemented without requiring radical adaptations in the institutional framework governing the electricity sector.

Although D-Cision and The Brattle Group (Hakvoort et al., 2009) recommended system redispatch with cost pass-through to generators, market redispatch, and a hybrid model –a combination of both the former– as the most appropriate congestion management options for the Netherlands, the Minister eventually remained with basic system redispatch, as the implementation of a method that creates a cost that is (only) allocated to generators in an area with excess production was considered to be in conflict with European legislation (van der Lee, 2010b). Basic system redispatch, with costs borne by the TSO, was therefore implemented in the Netherlands and will be used to manage congestion in at least the near future.

3. Congestion management methods

Congestion can be dealt with by a variety of measures, and the congestion management methods that are available can be implemented in different forms. Although practically all congestion management methods yield a similar result, in the sense that their application must eventually lead to a decrease in generation upstream from congestion and an increase (of equal volume) downstream, there is a variety of mechanisms available to achieve this outcome. Different methods use different criteria to determine which plants must be ramped up and ramped down, what financial streams must be created to achieve this (or are created as a result), and who benefits from congestion and who experiences a disadvantage.

A rich terminology is used throughout existing literature to refer to the available methods. Methods that possess similar – or even the same – characteristics may be referred to using different terms, and different authors may use the same term while referring to different methods.

On the basis of literature research that was performed in an effort to organize the congestion management terminology used by 34 authors, the present article distinguished six main categories of measures to alleviate congestion. For this structuring effort a number of existing, but for various reasons (scope, antiquity, author background, quality) incomplete congestion management method overviews were used as a starting point (Brunekreeft et al., 2005; Copenhagen Economics, 2006; Hakvoort et al., 2009; Kristiansen, 2007). All congestion management methods can be classified under one of these categories, which are shown in Table 1.

Active TSO intervention:
Transmission capacity adjustments
Direct capacity allocation
Redispatch using market-based criteria
Market coordination:
Auctioning of transmission rights
Price differentiation (to geographic area)
Demand-side measures:
Congestion solved by consumer reaction to situation

Table 1: Congestion management categories

3.1. Market-based congestion management methods

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, 2007). 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, 2007). 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 on the basis of market signals.

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 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 article 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.

3.2. Evaluated congestion management methods

Despite the overall tendency in Europe to apply market-based methods to manage congestion, as was discussed in Section 3.1, the Dutch government decided to implement the basic system redispatch method, which is not considered a market-based mechanism in the definition of Table 1. The outcomes from this approach may prove to be (very) different from those that would result from the application of a market-based method. To evaluate whether this is the case, this article 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 on important indicators –these are further elaborated in Section 5– such as congestion costs, the distribution therefore, the resulting investment incentives, and the opportunities to exert market power would be different under a market-based method.

This article 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

For those unfamiliar with the characteristics of these methods, a description of the methods is provided in Appendix B.

4. Quantitative model

In order to obtain an insight in the quantitative effects of the application of basic system redispatch, and to allow for a comparison to be made with the application of market splitting, market coupling, and the APX-based method, a model was constructed that captures the relevant elements of the Dutch electricity system and allows for calculating the effects of applying these methods. Section 4.1 discusses the main principles of the modeling technique that was used, section 4.2 indicates how the system was conceptualized and incorporated in the model, and section 4.3 introduces the different scenarios to which the model was made subject.

4.1. Modeling technique

The modeling objective is to provide a quantitative insight in the application of congestion management methods in the Netherlands, using the KPIs that will be introduced in section 5. 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 individual units and their characteristics as the starting point for dealing with congestion: all producers have 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, and together they determine the total dispatch pattern for the Netherlands, which results in a scheduled flow pattern for the transmission system.

When all (relevant³) 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 be still 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

3 Whether an individual unit is relevant, depends on its capacity. Small units (< 60 MWe) are not modeled separately, but are considered to be a part of a “competitive fringe”, as defined by Lise et al. (2006).

already dispatched and which are still available provides useful information on the underlying cause of congestion costs and it supports the identification of possibilities for producers to exert market power.

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 that the generation side is not incorporated in the model in full detail, but is treated as generic categories of generation units.

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 to be analyzed separately on the Dutch market. 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 article is written 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 the article.

4.2. System conceptualization

As is shown by Figure 1, the Netherlands is divided into 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 that exists in the Netherlands), the Maasvlakte (an industrial area where a significant share of new production capacity is planned), and Zeeland (including the Moerdijk industrial area). The decision to distinguish between these four regions is the result of a careful analysis of expected congestion, which was based on the expected developments of the Dutch electricity system (e.g. plans for production facilities, particularly in the Eemshaven and Maasvlakte, and the reorganization of the grid in Zuid-Holland (Derksen & van Houtert, 2011)).

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. 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.

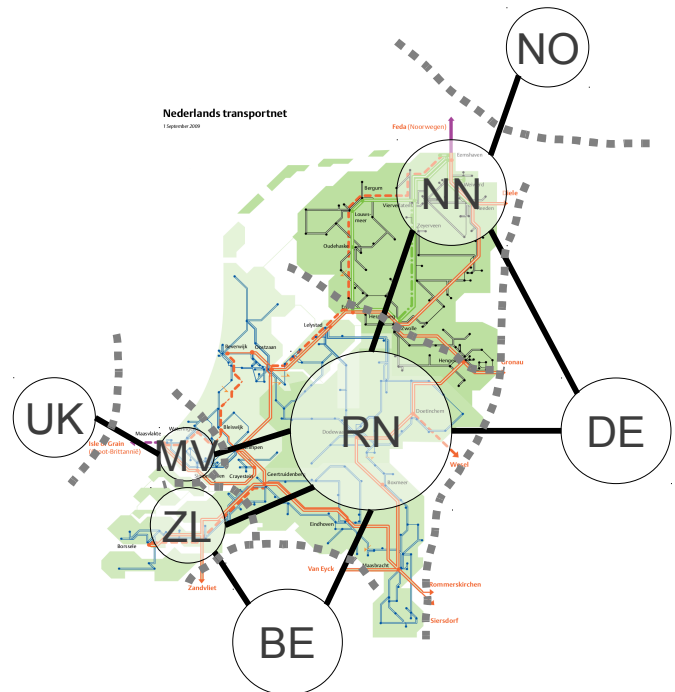


Figure 1: Nodal representation of the Netherlands

4.3. Scenarios

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 the succeeding sub-sections. Appendix A includes a full description of each of the models, including a discussion on their relevance for application during this modeling study.

4.3.1. Low wind availability in Germany

This scenario assumes large east-bound transmission flows that are created by relatively high Germany electricity prices, which are in turn the result of low wind availability which shifts the marginal generation unit to an old gas-fired plant, and low prices in the United Kingdom. Electricity is fed into the Dutch transmission grid at the Maasvlakte-node by the BritNed cable, while the Netherlands exports at full commercially available capacity to Germany and Belgium.

4.3.2. Cheap natural gas

If natural gas were to become cheap enough that gas-fired generation units run at variable costs below those of their coal-fired counterparts, this would be likely to lead to a different dispatch pattern across the country, resulting in changed transmission flows. This scenario allows for the simulation of the effects if this were to happen.

4.3.3. Green Revolution

The Green Revolution scenario assumes that more than

3 GW of offshore wind turbine capacity is constructed in the North Sea and that these run at full capacity at a given moment. This would increase the inflow at node Ring and possibly reduce the market price, thereby altering transmission flows within the Netherlands and with its interconnected neighbors.

4.3.4. Code Red

Most of the production capacity that would be affected by cooling water restrictions that arise from exceptionally warm surface water temperatures are located in the central part of the Netherlands (nodes RN and ZL), whereas capacity that is not as likely to be affected by this problem is located at the coastal regions of nodes NN and MV. If cooling water restrictions are put in place, this would likely lead to a significant shift in unit dispatch and, as a consequence, transmission flows.

5. Key performance indicators

The four congestion management methods that are considered in this study are evaluated by means of a quantitative simulation model, which was introduced in Section 4. The effect of applying these methods will be evaluated on the basis of four key performance indicators (KPIs), which will be introduced in the present section.

5.1. Region congestion sensitivity

Although congestion is expected to arise particularly on the grid infrastructure connecting the Maasvlakte and the Ring congestion regions, the extent of this congestion is currently still unclear for TenneT. Also, the system effects of the scenario conditions, when they arise, have not yet been accurately quantified. Apart from creating an insight in the development of congestion, which is highly relevant to the Dutch TSO, the insight in the sensitivity of regions to be affected by congestion is also related to the assessment of congestion management methods. 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 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, because it has an influence on how results should be interpreted.

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. Congestion will be measured on the basis of the volume that needs to be redispatched from the upstream congestion region, to the downstream region. It is quantified by the Extent of Congestion Index (ECI), which was developed for application in the present modeling study. The ECI measures the extent of congestion as the share of capacity that needs to be redispatched in the downstream area to alleviate congestion, as a share of the non-dispatched capacity that is available for this purpose:

$$ECI = \frac{P_{constrained\ on}}{P_{not\ dispatched}} \quad (\text{Equation 1})$$

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 then considered relatively more 'congestion sensitive' if it is more vulnerable to congestion (i.e. scores higher on the ECI) under different scenario conditions than other regions. The 'Region congestion sensitivity' KPI will eventually result in an overview that 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.

5.2. Congestion cost and distributive effects

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 lead to a decrease of total social welfare, because the system is unable to achieve least-cost dispatch. Note that if this "new" dispatch arrangement was more efficient, it would have been implemented by the market in the first place.

Despite the eventual decrease of net social welfare, different congestion management methods use different mechanisms to achieve the new dispatch pattern that results in this decrease, thus causing congestion costs to be distributed among society in a different manner. To obtain a full insight in the effect of different methods, three cost components will be distinguished:

- Consumer surplus
 - Upstream area
 - Downstream area
- Producer surplus
 - Upstream area
 - Downstream area
- TSO surplus
 - National congestion
 - International congestion

5.3. Incentives for long-term behavior

The distribution of congestion costs (and benefits) over society creates different incentives for market players to adapt their behavior. Depending on the welfare effects of these methods, they may, for instance, encourage or discourage investments in areas with excess production capacity.

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.

5.4. Market power

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:

$$RSI [\%] = \frac{C_{total} - C_{largest}}{L_{total}} \quad (\text{Equation 2})$$

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.

5.5. Overview of key performance indicators

To summarize the preceding sub-sections, an overview of the key performance indicators that are used during congestion management method evaluation is provided below. Note that the net welfare effect and distributive

effects of congestion management methods are essentially two components of the same indicator: congestion costs are allocated to market players by a varying degree, and, vice versa, the net effect of these distributive effects equals total congestion costs.

- Extent of Congestion Index
- Congestion cost
 - Net welfare effect
 - Distributive effects
- Incentives resulting from this distribution
- Residual Supply Index (RSI)

6. Simulation results

This section discusses the results that were obtained after running the simulation model, first with respect to the arising of congestion (6.1) and subsequently with respect to the (potentially) different outcomes of applying different congestion management methods (6.2).

6.1. Extent of congestion

Running the simulation model under the conditions of all four scenarios revealed that the Dutch electricity system is rather robust. Only in case of large east-bound flows, as which arose under the *Low wind availability in Germany* scenario, a significant amount of congestion can be expected in the Netherlands. Such a situation would be created when the Netherlands exports a large amount of power to Germany and Belgium (during simulations 6,000 MW was assumed for the year 2016 under this scenario), while BritNed is used at its full capacity to import 1,000 MW from the United Kingdom. Because the variable cost of production in the Maasvlakte region is relatively low due to the presence of new and efficient units, this region was found to have a relatively large share in Dutch production. As the internal demand of the region is low, this creates power flows in eastbound direction, particularly when BritNed also transports power eastward (i.e. electricity is imported from the United Kingdom). This effectively imposes an extra 2,000 MW⁴ on the grid between Maasvlakte and Ring compared to the situation in which BritNed is used to export power.

The *Low wind availability in Germany* scenario, which included the above mentioned foreign trade flows, resulted in an amount of congestion of 1,292 MW between the Maasvlakte and Ring. This corresponds with an ECI value of 10.58%, which indicates that redispatching this 1,292 MW would only require 10.58% of the initially non-dispatched capacity in regions outside the Maasvlakte to be dispatched in order to solve congestion.

Under the *Code Red* scenario congestion remained

⁴ BritNed has a capacity of 1,000 MW, and as a result the difference between imports (+1,000 MW) and exports (-1,000 MW) cause power flows within the Netherlands (MV-RN) to be affected by a load difference of 2,000 MW.

limited to 59 MW (ECI: 0.79%), while under the *Cheap natural gas* and *Green Revolution* scenarios no congestion arose at all. This is mainly related to the fact that, as was mentioned above, the Maasvlakte has relatively cheap production capacity available. As a result, a relatively large proportion of capacity is already dispatched under normal circumstances. If external factors cause a rearrangement of the unit dispatch pattern, there is not much capacity left in the Maasvlakte area that can be additionally dispatched. Also, the units that remain available in the Maasvlakte (under normal conditions) after other units in the area have been dispatched, have higher variable costs than the units that are still available in other parts of the country, which, as a result, will be dispatched first if so required.

6.2. Evaluation of congestion management methods

Under the two scenarios in which congestion occurs (*Low wind availability in Germany* and *Code Red*) congestion costs were found to be very low, with total social welfare losses of only € 231 and € 0 per hour, respectively. These costs were low because of the highly similar cost structures of generation units that would need to be constrained off in the upstream area and constrained on in the downstream area in order to solve congestion. However, the distribution of congestion costs shows large variations, as is shown by Table 2 for the *Low wind availability in Germany* scenario.

Cost (Scen. 1)	BSR ⁵	MS ⁶	MC ⁷	APX ⁸
Consumers	€ 0	€ 1,258	€ 1,258	€ 0
- Upstream	€ 0	€ 1,258		€ 0
- Downstream	€ 0	€ 0		€ 0
Producers	€ 0	€ 5,305-	€ 5,305-	€ 231-
- Upstream	€ 0	€ 5,305-		€ 231-
- Downstream	€ 0	€ 0		€ 0
TenneT	€ 231-	€ 3,817	€ 4,305	€ 0
- 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 2: Congestion cost distribution (Scenario 1)

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

5 Basic system redispatch.

6 Market splitting.

7 Market coupling.

8 APX-based method.

among society. Under these methods the social welfare loss is allocated to one single (type of) stakeholder (TSO and upstream generators, respectively).

Because each method leads to different stakeholders being 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 is argued by Ackermann (2007) – might affect production, consumption, and – as a consequence – transmission patterns in the longer term. The following sub-sections discuss the incentives that are created by this cost distribution for each of the methods.

6.2.1. 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 other generators are not involved in the congestion management scheme and are not required to take any action.

TenneT can solve congestion by reinforcing or expanding the transmission grid. 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 unlikely to be present during every single hour of the year.

It is important to point out that tariff structure regulations could provide an incentive for TSOs to take economically inefficient actions (i.e. encourage it to invest in the grid) when congestion costs are actually too small to make grid investments economically efficient. If a TSO is allowed to transfer the cost of grid infrastructure investments to consumers, while it must bear congestion costs by itself, the TSO would rather invest in grid capacity because investment costs can be incorporated in transmission tariffs, whereas the (smaller) 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, it would still be in the interest of the TSO to invest anyway, because unlike congestion costs, it can recover the costs related to these investments.

To solve this potentially perverse incentive, the regulatory framework could be adapted as to allow for a TSO to pass on congestion costs, for instance for a period

of 5 years, if it can show that the societal cost of alleviating congestion by means of grid expansions would outweigh the congestion costs that otherwise arise. In the Netherlands a scheme was implemented that allows the TSO, TenneT, to pass on congestion costs that have a temporary nature, whereas structural congestion costs must be borne by the TSO as an incentive to mitigate these by creating the necessary expansions.

6.2.2. 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 much larger fluctuations than the total cost itself creates. This is caused by the nature of the approach which involves all market players, rather than only those needed to solve congestion as with basic system redispatch. Under market splitting the market clearing price (MCP) is adjusted in two or more congestion regions in order to solve congestion and provide an incentive to adapt behavior. As fluctuations in the MCP affect all stakeholders (in that area) rather than only those required to solve congestion, its impact is larger despite having the same net effect.

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. It provides 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 TenneT financially benefits from congestion. On the basis of the distributive effects of market splitting it 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.

Alternatively, Bjørndal & Jörnsten (2007) and Kristiansen (2007) 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.

6.2.3. 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 would result in a benefit for the TSO in the Netherlands, as TenneT no longer needs to compensate a TSOs 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.

6.2.4. APX-based method

Because a cost is incurred to be 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. The TSO only faces a cost if the cost of production in the upstream area is relatively expensive, because in this case they cannot fully transfer the cost of constrained on power and must bear a share by itself. Consumers are not financially incentivized at all under the scheme.

Because more than 3200 MW of congestion would need to arise in the Netherlands before TenneT could expect to need to bear some of the cost arising under the APX-based method, one can conclude that the method will in practice primarily create an incentive for producers in the Maasvlakte area which has excess production in place.

7. Discussion

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 conditions⁹. 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 area¹⁰. 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).

The distribution of these costs may create larger differences for some stakeholders, however. As these distributive effects are different among the methods, they therefore provide different long-term incentives for market parties to adapt their behavior.

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.

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. Under the APX-based method, which also allocates congestion costs to generators in the upstream areas, the resulting incentive is much smaller. These methods lead to economically efficient outcomes from a transmission system efficiency perspective, because they impose an 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 the scope of this article is limited to generators).

However, this could also lead to socially undesirable actions. Although a price is attached 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 be¹¹ socially desirable from 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.

The proposition that market-based methods lead to more efficient outcomes than non-market-based methods, which was introduced in Section 3.1, 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 section discussed that there are relevant factors other 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).

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

⁹ The estimated peak load in the Netherlands for 2016, minus imports from UK and Norway, plus exports to Germany and Belgium, is approximately 26 GW.

¹⁰ 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.

¹¹ Evaluating the precise effects on and from geographical siting considerations did not fall within the scope of this article. Hence, 'may be' is preferred above 'is'.

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, and important regulatory considerations were addressed.

Appendix A: Scenarios

This appendix provides the full scenario descriptions that were used to simulate the model using different input factor values. It also indicates the practical relevance of each scenario.

A.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.

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. 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.

A.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 CO₂ emission right is at an almost record low. And hardly anyone cares.

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.

A.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.

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 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.

A.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.

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 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.

Appendix B: Description of methods

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 (2007), and Pignon (2002).
Advantages: Economically efficient Increased liquidity (compared to nodal pricing, market coupling) Locational incentives are provided
Disadvantages: No incentive for TSO to expand capacity
Market coupling
Market coupling distinguishes a number of nodes in an electricity system, each of which is assured (or assumed) to have no internal congestion. The market coupling mechanism determines a spot market outcome for each node separately and subsequently calculates the optimal (e.g. maximizing social welfare, as is currently the case in the North-West European region) transmission flows between these areas. Price differences among the nodes are leveled if sufficient transmission capacity is available, and a scarcity is reflected in different prices. See EMCC (2011).
Advantages: Economically efficient Locational incentives are provided
Disadvantages: No incentive for TSO to expand capacity
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 (2009).

Advantages:

Uniform pricing is maintained
Incentives for capacity expansion are maintained

Disadvantages:

Provides no locational incentives for demand

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:

Cost allocation flexibility
Low transaction costs

Disadvantages:

No incentives to locate outside congestion area
Vulnerable to market power and gaming

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