Net Benefits of a New Dutch Congestion Management System

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Abstract

The present study analyses the new connection policy that seeks to lift restrictions on grid connection. The new policy is expected to result in an increase of investments in generation capacity and increasing levels of congestion on the national transmission system. A scenario-based, quantitative analysis of the net benefits of the new connection policy is presented. Here net benefits are defined as the potential increase of consumer surplus and producer gross margins minus the cost of congestion. Further, several alternative designs for a congestion management system are evaluated. In this assessment a series of advantages and disadvantages of each of these systems is identified and presented.

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Samenvatting

De afgelopen jaren zijn er veel nieuwe investeringen in productievermogen voor elektriciteit in Nederland aangekondigd. Daarmee neemt de kans dat de transportcapaciteit voor elektriciteit in sommige gebieden te kort zal gaan schieten sterk toe. De landelijk netbeheerder TenneT en de regionale netbeheerders zijn verantwoordelijk voor de benodigde investeringen in de uitbreiding van het transportnetwerk. Het blijkt in de praktijk echter meer tijd te kosten om transportcapaciteitsuitbreiding te realiseren dan om productiecapaciteitsuitbreiding te realiseren. Dat leidt ertoe dat in voorkomende gevallen onvoldoende netwerkcapaciteit aanwezig zou kunnen zijn om geproduceerde elektriciteit naar de elektriciteitsgebruikers te transporteren.

In eerste instantie is hierop door netbeheerders gereageerd door een restrictief aansluitbeleid te voeren. Verzoeken om aansluiting van nieuw vermogen werden niet of conditioneel gehonoreerd ingeval gevreesd werd dat de transportcapaciteit niet volstond. Tevens werd een proces van consultatie en overleg gestart ten einde oplossingrichtingen voor de congestieproblematiek in kaart te brengen. In navolging hiervan heeft de Minister van Economische Zaken een nieuw aansluitbeleid aangekondigd waarbij niet langer sprake zou zijn van weigering van aansluiting van nieuw vermogen, in anticipatie op de invoering van een systeem voor congestiemanagement. Een dergelijk systeem voor congestiemanagement zou in geval van congestie moeten leiden tot toewijzing van de beperkte transmissiecapaciteit. Over de invulling van een dergelijk congestiemanagement systeem is nog geen besluit genomen.

Een congestiemanagement systeem is er op gericht congestie op te lossen. Producenten die aangesloten zijn in regio's waar congestie optreed of congestie verwacht wordt, de zogenaamde congestiegebieden, zullen in een dergelijk systeem deelnemen. Conform de vereisten in verband met programma verantwoordelijkheid, zullen producenten productie nomineren voor de volgende dag. Het voorgaande proces van allocatie van productiefaciliteiten wordt gewoonlijk *dispatch* van het productiepark genoemd. In geval er congestie verwacht wordt door de netbeheerder, zal het congestiemanagement systeem voorzien in een coördinatiemechanisme om de geplande productie zodanig te wijzigen dat er geen congestie meer zal optreden. Als resultaat zal geplande productie in de congestie regio's gereduceerd worden, terwijl gelijktijdig de geplande productie in andere regio's zal toenemen ten einde de totale geplande productie ongewijzigd te laten. Een dergelijke wijziging van geplande productie wordt gewoonlijk *redispatch* van het productiepark genoemd.

Doelstelling

De verwachting is dat het nieuwe aansluitbeleid bepaalde drempels voor markttoegang zal wegnemen en daardoor zal leiden tot versnelde realisatie van investeringen in nieuw productievermogen. Naar verwachting zal hiermee de beschikbaarheid van nieuwe productiecapaciteit met relatief lage marginale kosten van productie toenemen. Daarmee zal een neerwaartse druk op de prijzen op de Nederlandse elektriciteitsmarkt ontstaan. Daar staat tegenover dat er een toenemend risico op congestie ontstaat. Deze congestie zal moeten worden geadresseerd door geplande (en verkochte) productie in congestiegebieden over te hevelen naar andere gebieden in Nederland waar geen congestie is. De kosten van extra productie in die non-congestiegebieden zullen hoger liggen dan de kosten van productie van de af te schakelen eenheden in de congestiegebieden: die extra productie was immers niet gepland en verkocht. Congestiemanagement zal dus leiden tot een toename van de totale kosten van productie ten opzichte van de situatie waarin voldoende transmissiecapaciteit beschikbaar zou zijn geweest. Deze kostentoename moet in mindering gebracht worden op de baten van het nieuwe aansluitbeleid. Daarnaast dient er nog een invulling gegeven te worden aan het congestiemanagement systeem. Verscheidene modellen voor congestiemanagement zijn voorgesteld, elk met zijn eigen voor- en nadelen. Het ontwerp van het congestiemanagement systeem heeft grote invloed op de efficiëntie van aangepaste allocatie van het productiesysteem, en dus de totale toename van productiekosten, in geval van congestie. Verder heeft het ontwerp grote consequenties voor de welvaartseffecten van congestie voor de verschillende belanghebbenden. Deze welvaartseffecten kunnen bovendien beïnvloed worden door mogelijkheden tot strategisch gedrag voor de verschillende deelnemers.

De doelstelling van dit rapport is om een kwantitatieve analyse te geven van de netto baten van het nieuwe aansluitbeleid, dus inclusief de bijbehorende kosten van redispatch, en om een analyse te geven van de welvaartseffecten van verschillende congestiemanagement systemen. Het gaat om de volgende elementen:

1) *Analyse van de potentiële baten van het nieuwe aansluitbeleid*
   Dit betreft een kwantitatieve analyse van de baten van het nieuwe aansluitbeleid in verschillende scenario's die relevante en mogelijke ontwikkelingen van de Nederlandse elektriciteitsmarkt in de nabije toekomst representeren, uitgaande van de veronderstelling dat er sprake is van een competitieve elektriciteitsmarkt.
2) *Analyse van de potentiële kosten van redispatch ten gevolge van congestie*
   Dit betreft een kwantitatieve analyse van de systeemkosten van productie ten gevolge van congestie in de veronderstelling dat de elektriciteitsmarkt competitief is en er efficiënte redispatch plaats heeft, uitgaande van verschillende scenario's die relevante en mogelijke ontwikkelingen van de Nederlandse elektriciteitsmarkt in de nabije toekomst representeren.
3) *Analyse van de welvaartseffecten van verschillende congestiemanagement systemen*
   Dit betreft een kwantitatieve analyse van de welvaartseffecten van verschillende congestiemanagement systemen voor de verschillende belanghebbenden, gegeven een bepaald congestie scenario, zowel in geval van de situatie dat de deelnemers zich niet strategisch gedragen als de situatie dat de deelnemers zich wel strategisch gedragen met betrekking tot het congestiemanagement systeem.

Met betrekking tot de laatste doelstelling, heeft het Ministerie van Economische Zaken vier congestiemanagement systemen uit het eerdere onderzoek van Hakvoort et al. (2009) geselecteerd voor deze nadere analyse. De geselecteerde systemen betreffen het 'system redispatch' model met doorberekening van kosten aan de producenten, het 'market redispatch' model, het 'hybrid redispatch' model, en de 'market agent' benadering, zoals hieronder nader toegelicht:

System redispatch
In dit model is TenneT verantwoordelijk voor het oplossen van de verwachte congestie. Producenten in het congestiegebied geven aan welke prijs ze willen betalen om af te zien van voorgenomen productie. TenneT ontvangt inkomsten van de hoogstbiedenden. Ter compensatie van de hiermee weggevallen productie koopt TenneT eenzelfde hoeveelheid extra elektriciteitsproductie buiten het congestiegebied. Omdat de prijs hiervoor altijd hoger zal zijn dan de prijs waarvoor producenten in het congestiegebied van productie willen afzien, levert dit netto altijd extra kosten op voor TenneT. Deze congestiekosten doorberekend worden aan de producenten in het congestiegebied.

Market redispatch
In dit model organiseert TenneT een markt voor 'congestierechten'. Producenten moeten aangeven hoeveel ze over hebben voor het recht om te mogen produceren, indien er congestie optreedt. Op basis hiervan wordt een congestieprijs vastgesteld op een zodanige hoogte dat er voldoende productie afvalt om congestie te voorkomen. Producenten die afzien van voorgenomen productie zijn daarna zelf verantwoordelijk om dit te compenseren met extra productie buiten het congestiegebied.

Hybrid redispatch
Dit model verschilt van het market redispatch model, doordat niet de producenten, maar TenneT verantwoordelijk is voor de aankoop van extra geproduceerde elektriciteit ter compensatie van het wegvallen van voorgenomen productie in het congestiegebied. Het verschil tussen de kosten hiervan en de baten van de congestierechten kan positief of negatief uitpakken voor TenneT.

Market agent
In de 'market agent' benadering wordt de totale beschikbare transmissiecapaciteit naar evenredigheid van opgesteld vermogen over de verschillende producenten in het congestiegebied verdeeld door middel van het beperken van transportrecht. Het wordt daarna aan de producenten zelf overgelaten om hun productie te beperken tot het niveau van het transmissierecht óf van andere producenten een hoeveelheid productieverplichtingen en bijbehorende transportrechten over te nemen. Nadat de productieverplichtingen en bijbehorende transportrechten verdeeld zijn, ligt de verantwoordelijkheid voor alle verdere activiteiten, en daarmee ook de verdere kosten van het voorkomen van congestie, geheel bij de producenten met productievermogen in het congestiegebied.

Resultaten
Het eerste deel van dit rapport gaat in op de analyse van de baten van het nieuwe aansluitbeleid en de bijbehorende redispatch kosten. Gezien de samenhang tussen baten en redispatch kosten worden voor elk van de scenario's beiden gepresenteerd in een integrale analyse. Uit de analyse blijkt dat de baten in vrijwel alle scenario's significant zijn, zowel voor consumenten als voor producenten. Ze liggen in de orde van grootte van enkele honderden miljoenen Euro's per jaar. De efficiënte redispatch kosten kunnen oplopen tot enkele tientallen miljoenen Euro's per jaar. Uit alle simulaties volgt dat de baten de bijbehorende redispatch kosten met een orde van grootte overstijgen. Het absolute niveau van de resultaten dient met voorzichtigheid geïnterpreteerd te

worden, maar geconcludeerd kan worden dat de baten van het nieuwe aansluitbeleid de bijbehorende redispatch kosten in belangrijke mate overstijgen.

Het tweede deel van dit rapport gaat in op de welvaartseffecten van de vier verschillende congestiemanagement systemen. In de eerste plaats wordt uitgegaan van efficiënte redispatch, met perfecte informatie en onder de veronderstelling dat de deelnemers geen strategisch gedrag vertonen. Tevens wordt kwalitatief besproken of efficiënte redispatch mogelijk gecompromitteerd kan worden in de praktijk. Bovendien wordt kwalitatief ingegaan op verscheidene criteria met betrekking tot economische efficiëntie, toegankelijkheid en de eventuele directe of indirecte blootstelling van de netbeheerder en consumenten aan de kosten. Na deze evaluatie wordt ingegaan op de mogelijkheden voor producenten om middels strategisch gedrag de eigen opbrengsten structureel te verhogen. In een systematische analyse worden deze mogelijkheden voor verschillende categorieën producenten onderzocht. Hierbij worden de mogelijkheden tegen het licht gehouden om opbrengsten te verhogen door ofwel de biedprijs ofwel het biedvolume in de markt voor af te schakelen vermogen en de markt voor op te schakelen vermogen strategisch aan te passen.

Uitgaande van efficiënte redispatch, met perfecte informatie en onder de veronderstelling dat de deelnemers geen strategisch gedrag vertonen, verschillen de systemen niet in totale redispatch kosten. De systemen leiden wel tot verschillende distributieve effecten, i.e. voor wat betreft de welvaartsoverdracht tussen de verschillende belanghebbende partijen. Uit de analyse volgt dat met name het ‘market redispatch’ model sterke distributieve effecten laat zien: de welvaartsoverdracht van producenten naar de netbeheerder is veel groter dan de onderliggende redispatch kosten. Bovendien is het aannemelijk dat in dit model de redispatch minder efficiënt wordt indien een maandelijkse bieding op de markt voor de het af te schakelen vermogen georganiseerd wordt, omdat in dat geval de producenten geen effectieve inschatting kunnen maken van de kosten van compenserende productie. Een andere invulling van deze biedprocedure kan dit probleem ondervangen, maar in dat geval zal het mogelijke voordeel voor wat betreft de verminderde transactiekosten wegvallen. De ‘market agent’ benadering vereist dat een efficiënte en liquide secondaire markt voor productievermogen ontstaat of wordt ontwikkeld. Indien aan deze randvoorwaarde voldaan wordt, laat dit model tamelijk goede prestaties zien op de meeste criteria. Slechts voor wat betreft de toegankelijkheid voor kleine producenten en de transactiekosten lijkt dit systeem minder aantrekkelijk. Het ‘system redispatch’ model met doorberekening van kosten aan de producenten heeft als belangrijkste nadeel dat de lange termijn efficiëntie van het model te wensen overlaat. In geval van congestie ontvangen producenten die worden afgeschakeld in dit model compensatie voor de weggevallen opbrengsten. Dit vermindert de prikkel om productiefaciliteiten uit productie te nemen. Een belangrijk voordeel is dat dit systeem aansluit bij de huidige praktijk en vermoedelijk relatief eenvoudig geïmplementeerd kan worden. Het belangrijkste nadeel van het ‘hybrid system’ model betreft het feit dat de TSO blootgesteld is aan mogelijke verschillen tussen de opbrengsten van het congestietarief en kosten van redispatch. Indien de kosten van redispatch worden doorberekend aan de producenten, conform de voorgestelde methodiek voor het ‘system redispatch’ model, valt dit nadeel weg.

In geval van de evaluatie van mogelijkheden tot strategisch gedrag, volgt dat de mogelijkheden voor structurele verhoging van de opbrengsten op markt voor op te schakelen vermogen in alle congestiemanagement modellen vergelijkbaar zijn. Voor wat betreft de mogelijkheden om strategisch te opereren op de markt voor af te schakelen vermogen binnen het congestiegebied zijn er wel verschillen. Uit de analyse volgt dat met name het ‘system redispatch’ model met doorberekening van kosten aan de producenten en de ‘market agent’ benadering mogelijkheden laten zien voor structurele strategische aanpassing van het biedvolume. Dit leidt tot een andere verdeling van opbrengsten ten behoeve van producenten die in aanmerking komen voor afschakeling en ten koste van producenten die hiervoor niet in aanmerking komen. Voor wat betreft het absolute niveau van de omvang van de opbrengsten van deze vorm van strategisch gedrag (en van de kosten voor anderen) dienen de scenarioresultaten met voorzichtigheid geïnterpreteerd worden, omdat die sterk afhangen van de specifieke (scenario)omstandigheden. Een belangrijke constatering is wel dat deze beide systemen geen intrinsieke mechanismen kennen om dergelijk strategisch gedrag te beperken. Het ‘market redispatch’ model en het ‘hybrid redispatch’ laten mogelijkheden zien om het transmissie tarief, i.e. de prijs voor congestierechten, te beïnvloeden door strategische aanpassing van de biedprijzen op de markt voor transmissie rechten. In geval van het ‘hybrid redispatch’ model loopt de netbeheerder hiermee het risico de inkomsten mis te lopen die nodig zijn om de kosten van redispatch te dekken. Ook in dit geval geldt dat indien er een alternatieve invulling wordt gegeven aan het ‘hybrid redispatch’ model en de kosten van redispatch worden doorberekend aan de producenten, conform de voorgestelde methodiek voor het ‘system redispatch’ model, deze nadelen wegvallen.

Conclusies

Uit alle simulaties volgt dat de baten de bijbehorende redispatch kosten met een orde van grootte overstijgen. Echter, de feitelijke invulling van het congestiemanagement systeem heeft gevolgen voor de hoogte van de redispatch kosten. Bovendien heeft de invulling van het congestiemanagement systeem gevolgen voor de verdeling van de kosten. Daarnaast kennen de verschillende systemen elk de nodige voor- en nadelen voor wat betreft de economische efficiëntie, toegankelijkheid en de eventuele directe of indirecte blootstelling van de netbeheerder en consumenten aan de kosten. Uit de evaluatie van de onderzochte congestiemanagement systemen blijkt dat het ‘system redispatch’ model met doorberekening van kosten aan de producenten gevoelig is voor strategisch gedrag, met name voor aanpassing van het bied volume in de markt voor af te schakelen vermogen. Daarnaast is dit systeem niet efficiënt voor wat betreft de lange termijn. Vanwege het feit dat dit systeem compensatie biedt voor afschakeling kent het een verminderde prikkel om inefficiënte installaties in congestiegebieden uit productie te nemen. Het ‘market redispatch’ model laat zeer sterke distributieve effecten zien, waarmee bovendien het risico op prijsopdrijving in de elektriciteitsmarkt bestaat omdat er een reëel gevaar is dat de kosten van productie en transmissie zo hoog worden dat er minder productie wordt aangeboden. Daarnaast is dit systeem eveneens gevoelig voor strategisch gedrag op de markt voor af te schakelen vermogen. In het ‘hybrid redispatch’ model staat de netbeheerder bloot aan de risico’s dat de kosten voor redispatch niet gedekt worden door de inkomsten voor transmissie, wat bovendien versterkt kan worden door strategisch gedrag van de producenten. Tot slot is de efficiëntie van redispatch, in geval van de ‘market agent’ benadering, afhankelijk van het al of niet ontstaan van een efficiënte markt voor productievermogen. Indien dit systeem geïmplementeerd zou worden lijkt het raadzaam om additionele regelgeving in te voeren waarmee het ontstaan van een dergelijke markt bevorderd zou worden. Als alternatief op de genoemde systemen zou een ‘hybrid redispatch’ model met doorberekening van kosten aan de producenten overwogen kunnen worden. Met een dergelijk systeem zouden zowel de geïdentificeerde nadelen van het ‘system redispatch’ model met doorberekening van kosten, als de geïdentificeerde nadelen van het ‘hybrid redispatch’ model overkomen worden.

1. Introduction

In recent years a significant number of investment projects for new production capacity in the Dutch power market has been announced, in particular in the areas Eemshaven and Maasvlakte. Due to regional distribution of the potential increases in production capacity, such investments are thought to come with an increasing demand for transmission capacity. However, both the national transmission system operator (TSO) TenneT, as well as the distribution system operators (DSOs) face significant lead times for investments required to accommodate for the potential increase in demand for transmission capacity. Accordingly, the TSO and DSOs therefore initially responded by restricting access to the grid for new generation capacity. Alternative approaches addressing the expected congestion have been proposed and studied in a process of discussions with the various stakeholders. Finally a new policy regarding grid connection was announced in anticipation of the establishment of a required new congestion management system by the Minister of Economic Affairs. A new congestion management system is yet to be established however.

The new connection policy seeks to lift restrictions on grid connection which is expected to result in congestion on the national transmission system. A congestion management system is intended to resolve this congestion. Producers connected to the grid in regions that show or are expected to show congestion, i.e. *congestion regions*, will be required to participate in such a new system of congestion management. The congestion management system assumes producers to nominate production on a day-ahead basis as required for the system of program responsibility. The preceding process of allocation of production facilities is generally referred to as *dispatch* of the production park. In case congestion is expected by the TSO, the congestion management system will provide for coordination mechanism reallocating production facilities such that the expected congestion is resolved. As a result planned production in the congestion areas is decreased whereas the production outside the congestion areas is simultaneously increased with an equivalent amount in order to restore the balance of the energy program. This process of reallocation is generally referred to as *redispatch* of the production park.

The new connection policy that allows generators to connect new generation capacity to the grid is expected to result in benefits for various stakeholders, in particular for the consumers. An increased availability of new low-cost generation capacity will reduce marginal cost of production of power, may reinforce competitive pressure, and is therefore expected to result in lower prices on the Dutch wholesale market. More generally both consumer and producer surplus are expected to increase as a consequence of investment in generation capacity. In contrast however, congestion may limit the availability of new generation capacity to the wholesale market and therewith limit the potential increase of social welfare.

The first part of this study is intended to offer insights in the net benefits of the new grid connection policy and an associated congestion management system. The net benefits are assumed to involve overall benefits of the availability of new low-cost generation capacity while accounting for the cost that may arise due to congestion. Here, the overall benefits are evaluated as the potential rise in consumer surplus and the producer's *gross margin*, i.e. producer surplus excluding the investment costs associated with the new generation capacity. The costs of congestion will be characterized as the redispatch costs. The latter implies that no specific assumptions regarding the nature of the congestion management system are required for the analysis, other than that the congestion management system is expected to result in efficient redispatch, i.e. redispatch that

results in the lowest cost of production while respecting the transmission constraints. In addition the analysis assumes competitive pricing, i.e. pricing of power at marginal cost of production.
The second part of this study involves a quantitative assessment of several congestion management mechanisms as laid down and described in prior analysis by D-cision/The Brattle Group (Hakvoort, Harris, Meeuwsen and Hesmondhalgh, 2009). Here the Ministry of Economic Affairs has selected a subset of four congestion management systems to be evaluated out of the overall set of congestion management systems described in the analysis by Hakvoort et al. (2009). Following the nomenclature introduced in this analysis, the subset identified by the Ministry of Economic Affairs involves system redispatch with cost pass-through to generators, market redispatch, hybrid redispatch and the market agent approach. The quantitative analysis of these congestion management systems firstly involves an assessment of mainly the distributive effects of the congestion management systems considered, assuming non-strategic behaviour of the producers both with respect to the wholesale market as well as the congestion management systems and efficient redispatch. In the second stage the analysis is broadened considering strategic behaviour of producers with respect to the congestion management systems.

Both the analyses presented in the first and second part of this study involve scenario analyses on the basis of a computational model of the European power market, named COMPETES. The scenario analyses consider a variety of scenarios regarding investment in generation capacity, investment in transmission capacity and relative marginal costs of production of coal- and gas-fired production. The scenarios are mainly designed in order to provide insight in the robustness of the conclusions regarding the relative proportions of the benefits of the new connection policy and the associated redispatch costs, and the robustness of the conclusions regarding the (dis)advantages of the various congestion management systems.

Given the nature of the scenarios considered, the natural limitations that are inherent to mathematical modelling of power markets in general and the particular limitations that results from the implicit and explicit assumptions underlying both inputs and structure of the modelling framework applied, it is important to stress the fact that any reporting on simulated absolute levels of for example benefits, congestion, costs of congestion and distributive effects of the congestion management systems should be interpreted with care and can not be interpreted as a forecast or expectation with a range of uncertainty. In this report it has been attempted to stress the main limitations whenever absolute levels are reported, based on ECNs' experience with both mathematical modelling of power markets in general and ECNs' experience with the specific mathematical framework applied. However, given the complex nature of power markets it is not possible to provide for an exhaustive listing of all conceivable limitations of the simulated results.

2. Objective

The new connection policy is expected to facilitate investments in new generation capacity in the Dutch power market. The increasing availability of new low-cost production capacity should lead to a decreasing marginal cost of production. As overall costs of production decrease, prices on the Dutch wholesale market for electricity are expected to decline. As such the new connection policy is expected to yield benefits for the various stakeholders, in particular the consumers. However, increases in production capacity may outpace the required increases in transmission capacity and induce congestion. In general, congestion will require redispatch which induces additional costs of production for the system as a whole. Further, in order to resolve congestion, a congestion management system is yet to be established. A variety of congestion management system has been proposed in prior analysis, each of which is expected to show its favourable and unfavourable characteristics. The design of the congestion management system determines the welfare impact of congestion for the different stakeholders, i.e. the design may affect the cost of redispatch, and the distribution of these costs among the different stakeholders. Moreover, congestion management systems may differ with respect to the opportunities for gaming or the exertion of market power and the resulting consequences for the overall costs of redispatch and the distribution of these costs.

The general objective of the present study therefore involves a quantitative analysis of the benefits of the new connection policy, the associated costs of redispatch, and an assessment of the welfare effects of a variety of congestion management models considered. More specifically, the general objective comprises of three elements:

1) *Analysis of the potential benefits of the new connection policy*
   A quantitative analysis of the benefits of the new connection policy, assuming a competitive market under a variety of scenarios reflecting relevant and conceivable developments of the Dutch wholesale market for electricity in the near future.
2) *Analysis the potential costs of redispatch in the face of congestion*
   A quantitative analysis of the system cost of production resulting from congestion, assuming a competitive market and efficient redispatch under a variety of scenarios reflecting relevant and conceivable developments of the Dutch wholesale market for electricity in the near future.
3) *Analysis of the welfare effects of a variety of congestion management systems*
   A quantitative analysis of the welfare effects of various congestion management systems for the various stakeholders given some congestion scenario, both considering the situation that generators behave non-strategically and the situation that generators behave strategically with respect to the congestion management system.

With regard to the final element of the general objective, the Ministry of Economic Affairs selected four congestion management systems from prior analysis by Hakvoort et al. (2009) to be considered in the present study. The selected systems involve the system redispatch model with cost pass-through to generators, the market redispatch model, the hybrid redispatch model, and the market agent approach.

3. Methodology and Scenario Assumptions

3.1 Methodology

3.1.1 Brief description of the COMPETES Model

For the analysis of benefits and associated redispatch costs of a new congestion management system, a model of the European electricity market, COMPETES, is applied. This model was developed at ECN in 2002 and since its introduction the model has been extensively used for research on market concentration, market integration and congestion management issues. COMPETES is a partial equilibrium model, largely representing the European power market and specifically covering the wholesale markets in twenty European countries. The European power markets are represented by supply and demand on a national scale in each country covered, while the transmission network is represented as a meshed network on a country-to-country basis. Supply in each country covered is represented on a unit-by-unit basis, generally characterized by fuel-price dependent constant marginal costs and maximum output levels. Yearly demand is decomposed into some twelve typical demand curves representing three seasons (winter-, summer- and midseason) and four products (super peak, peak, shoulder and off-peak) in each country in a year and demand in each period and country may be specified by inelastic demand as well as by a linear approximation of a price-elastic demand curve.

The model solves for the equilibrium solution in the European electricity markets under different market structures varying from perfect competition to oligopolistic market conditions (Cournot competition). The equilibrium solution for competitive equilibrium may be specified as follows; given specific levels of demand and the characteristics of supply and transmission for the various markets covered, the solution specifies the least-cost/social welfare maximizing allocation of production and transmission. The associated market prices for power equate system marginal cost, while costs for transmission represent scarcity rents for transmission capacity. For a more elaborate description of the model and the underlying network structure, see Appendix A.

The COMPETES model assumes efficient allocation and pricing of the available transmission capacity of which the formulation is mathematical equivalent to the pricing on the basis of scarcity rents of transmission capacity as applies to the framework of locational marginal pricing (LMP).[1] LMP pricing of transmission capacity clears the markets such that social welfare for the system as a whole is maximized. Alternative pricing mechanisms, such as the newly proposed congestion management systems may yield different realisations of both congestion pricing and allocation of production and transmission. However the LMP solution for an electricity market with internal congestion will offer the most efficient solution of the market clearing. As such the LMP solution for the European electricity markets that show internal congestion will result in the allocation and pricing that is consistent with the maximum achievable social welfare for the (EU) system as a whole.

In case of perfect competition where producers bid their marginal costs, allocation of generation capacity and the national electricity price may be represented by equilibrium results for the single-node representation of the Dutch power market and other countries in COMPETES. The allo-

[1] LMP outcomes are directly comparable with the market splitting model as discussed in the analysis by Hakvoort et al. (2009).

cation of generation capacity after redispatch may be represented by the allocation of the multiple-node representation of the Dutch electricity market in COMPETES. Therewith one may simulate market-based dispatch and required redispatch of the Dutch power system through a single-node and a multiple-node simulation for a given scenario of demand, installed capacity, transmission capacity and fuel prices.

3.1.2 Outline of the Analysis

The following steps are taken for the analysis of the objectives in this study:

- A simplified representation of the Dutch network is incorporated in the COMPETES model for the purpose of this study. The model is extended by embedding a four node representation of the Netherlands in the EU network. The four node representation covers the Maasvlakte, Eemshaven, Zeeland and the centre of the Netherlands as separate nodes. The assumptions and details on the methodology used for the extension of the Dutch network are given in Section 3.2.
- Further, scenarios and the corresponding scenario assumptions which may have impact on the congestion pattern within Netherlands are identified. Under the limited connection policy, which restricts grid access for new generation capacity in congested areas in case of limited transmission capacity, a limited amount of new generation capacity is assumed to be realized in the non congestion areas. Under the new connection policy, which allows all new generation capacities to be connected to the grid, low and high new generation capacities are assumed to be realized in both congestion and non congestion areas. The detailed description of the scenarios and corresponding scenario assumptions are presented in Section 3.3 and Appendix B respectively.
- Based on the scenario assumptions, an indication of the benefits and redispatch costs are presented in Chapter 4.
  - For benefits, COMPETES with a single-node representation of the national network in all countries covered is simulated. The dispatch and price outcomes of the single-node representation for each country, including the Netherlands, would assess the impact of additional generation capacity in the Netherlands excluding the redispatch costs within the Netherlands due to internal congestion. We asses the benefits in by comparing current connection policy outcomes with Scenario outcomes under new connection policy in terms of welfare gains.
  - For the assessment of efficient redispatch costs, COMPETES with a multiple-node representation of the German and Dutch network is used for simulation. The corresponding generation allocation, respecting internal transmission capacity limitations within the Netherlands and Germany, represents efficient redispatch for a perfectly competitive market. The difference in total cost of generation between dispatch and redispatch results indicate the redispatch costs incurred under efficient and competitive market assumptions.
- For assessment of welfare effects of congestion management schemes, Chapter 5 compares (dis-)advantages of four congestion management systems of interest in terms of the quantitative assessment on the distribution of redispatch costs and qualitative assessment on the possible inefficiencies in these systems.
- For assessment of welfare impact of gaming, Chapter 6 presents welfare results in case strategic behaviour of participants is assumed.

3.1.3 Limitations of the Analysis

As any other mathematical model of power markets, COMPETES outcomes inherit particular limitations that results from the implicit and explicit assumptions underlying both inputs and structure of the modelling framework applied. Hence the absolute outcomes of benefits, congestion, costs of congestion and distributive effects of the congestion management systems should be interpreted with consideration of these limitations. The limitations which are relevant for this study can be summarized as follows:

i. As mentioned before yearly demand in COMPETES consist of twelve periods in a year. The demand levels in these periods represent average demand levels observed in a super peak, peak, shoulder, and off-peak hour of a particular season (winter, summer or mid-season). Hence, the redispatch volume due to congestion and the frequency of congestion observed in this study represent average outcomes of a season and may be interpreted somewhat lower than the outcomes observed due to hourly and daily variations of demand.
ii. The marginal costs of generation units in COMPETES are driven by generic technology-based efficiencies and average yearly fuel prices assumed for these technologies. The bids of generation units are assumed to represent their average short-run marginal costs in a year disregarding any additional mark-ups and volatility of fuel prices. Hence in combination with the average demand assumption mentioned above, the prices in COMPETES (in particular in peak hours) underestimates the actual market realisations.
iii. Similar to the electricity demand, the maximum output level of each generation unit is varied between the twelve periods. In particular wind power generation represents seasonal variations from the average yearly wind production. In combination with the average seasonal demand variations, the frequency of congestion observed in this study may be interpreted as an underestimated value in each scenario.
iv. The number of nodes assumed in the Netherlands determines the underlying network topology and the congested lines. The nodal decomposition should be as detailed as possible represented the existing and the expected congestion patterns in Dutch grid. For instance, the nodal decomposition in this study accounts for Zuid-Holland (ZH), the Northern Provinces (NN), the Province of Zeeland (ZL), and the circular HV-circuit in the centre of the Netherlands, called the ring (RN). Representing the ring as a single node would disregard any possible future congestion within the ring and the corresponding redispatch costs. However considering the future expectations for congested regions and the objectives of this study, the four-node decomposition of the Netherlands is detailed enough as explained in the next section.

3.2 Incorporating Dutch Network into COMPETES Model

In order to perform the intended analyses, a simplified representation of the Dutch transmission network was incorporated in the COMPETES model. The simplified nodal representation of the Dutch network was developed as follows: (1) Identify relevant level of aggregation of Dutch network, (2) identify transmission corridors in aggregated Dutch network (3) determine equivalent electrical characteristics of the transmission corridors, (4) insert Dutch detail nodes and transmission links into COMPETES model, and (5) calculate new power transfer distribution factors, or PTDFs. The network representation, both regarding the nodal decomposition as well as regarding quantification and representation of the characteristics of transmission corridors were designed in cooperation with TenneT.

1. Identify relevant level of aggregation of Dutch network

The representation of Dutch grid should provide for a sufficient level of detail to represent regions that are expected to show congestion over the course of the coming years. According to TenneT, congestion in the extra high-voltage grid is primarily expected to arise in Zuid-Holland (ZH) due to investments in new generation capacity in the Maasvlakte and in the Northern part of the Netherlands (NN) due to investments in generation capacity in Eemshaven. The nodal decomposition therefore accounts for Zuid-Holland (ZH) and the Northern part of the Netherlands (NN). These regions are connected to the circular HV-circuit in the centre of the Netherlands, called the ring (RN).[2] In addition, the Province of Zeeland (ZL) is distinguished as this Province may affect international transmission. The nodal representation of the Dutch network developed for this study is presented in Figure 3.1.

2. Identify transmission corridors connecting new detailed Dutch nodes

The second step was to identify the transmission corridors connecting the hubs of each node to one another. The transmission corridors are identified by using the Dutch high voltage network map provided by TenneT. This was done by examining the high voltage network map and the transmission lines that connected these buses, but rather than make a note of every line, the main bundle of lines that connected the hubs are identified.

3. Determine equivalent electrical characteristics of new transmission corridors

After identifying the main transmission corridors, the equivalent electrical characteristics of these corridors - in particular the reactance and the transmission capacities - are calculated in order to incorporate them into the model. These electrical characteristics are identified on the basis of publicly available info on the Dutch high voltage grid, to be agreed upon by TenneT. Each corridor reactance was determined by summing the line reactances, either in series or parallel, of the lines in the corridor.

The capacities of transmission lines within Netherlands represent the *net transfer capacity*[3] (NTC) as assessed by TenneT[4]. TenneT indicated the current NTC values for each transmission corridor which are given in Figure 3.1. The future NTC values- after the project Randstad 380 zuid and the link between Northern provinces and the ring is realized- assessed by TenneT are given as scenario assumptions in Section 3.3 and Appendix B. In addition, there are two types of limitations of transmission flows between the Netherlands and the neighbouring countries. One is the total import/export limitations between the Dutch electricity market and the neighbouring countries determined by TSOs on the basis of safe *operational capacity*[5] limits. Figure 3.1 represents the safe import/export capacities of the Netherlands assumed for all the future scenarios. Another limitation at the border is the individual secure transport capacity of each transmission corridor between the Netherlands and the neighbouring countries, which are presented in the network representation of multiple node simulations for each future scenario in Appendix C.

4. Insert Dutch detail nodes and transmission links into COMPETES model

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[2] It has been considered that further decomposition of the ring would provide for insights regarding the consequences of the meshed structure of the Dutch transmission system. Such structures may lead to the arise of loop flows limiting available transmission capacity for flows transiting the loop. However TenneT indicated that no congestion was expected to arise on the ring over the course of the coming years. In addition, in case of congestion, such a loop structure provides for a system that may show congestion in circular patterns which imposes additional requirements on the congestion management system implemented as the dual linkage should be intrinsically consistent in terms of for example the congestion fees on both links. International experience suggests that the only congestion management systems that effectively address such phenomena are based on LMP. However, LMP is not considered as a short-term solution for congestion management by the Ministry of Economic Affairs as it is complex and time consuming to implement.

[3] *Net transfer capacity* is defined as the maximum secure transport capacity of the transmission corridor under (n-1) security constraint.

[4] See for example ‘Tool vermogentransport Maasvlakte’ and ‘Tool vermogentransport Noord-Nederland’ at www.tennet.org.

[5] *Operational Capacity* is defined as the secure import/export values between two regions/countries that are based on the limitations of the electricity grid within these regions/countries. The value of the operational capacity of a transmission corridor is generally lower than its NTC value.

The next step was to integrate the transmission links connecting the new Dutch detail nodes with the links connecting the existing COMPETES country nodes. Essentially, the Dutch node in the former COMPETES model was replaced by the new four nodes, and the transmission links between Dutch and the other countries were replaced by the new transmission links between the detailed Dutch nodes and the other COMPETES countries.

5. Calculate new PTDFs

The COMPETES model uses power transfer distribution factors, or PTDFs, to model flow on the network. The final step in creating the new model was to convert the reactance model into a PTDF model. The process of doing this is based on physical behaviour of electrical networks: Kirchhoff's current and voltage laws. Kirchhoff's current law states that all current entering a given point on the network must sum to zero; this is essential an energy balance constraint that disallows creation of current or power from nothing. Kirchhoff's voltage law states that around any closed loop in an electrical network, the voltage drops across each segment sum to zero. Using these two laws, along with the reactance of the network links, one can model power flows on a network. Representing these physical laws, or constraints, as a matrix, it is then possible to invert the matrix and derive the PTDFs of the network. Thus, by using the reactances calculated in the previous steps of this process, and identifying each point where current sums to zero, and each loop where voltage drops sum to zero, we calculated the PTDFs of the COMPETES model with the new detailed Dutch nodes.

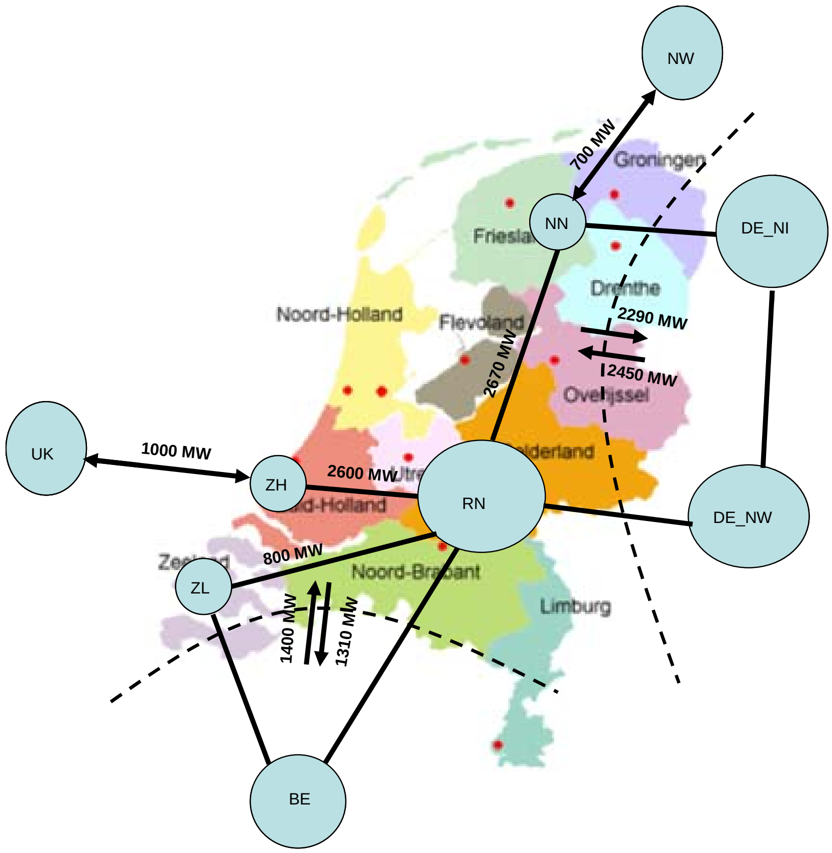

Figure 3.1 *Representation of current Dutch network in COMPETES*

3.3 Scenario Description

In this section the scenarios designed for this study are presented. These scenarios synthetic in nature, mainly designed in order to evaluate the robustness of the derived relation between the benefits of the new connection policy and the associated redispatch costs. In addition robustness of the identified (dis)advantages of the various congestion management systems is evaluated on the basis of these scenarios as well.

To this end, firstly a reference scenario was developed representing the prior situation of limited access to the Dutch grid. In addition a baseline scenario was developed reflecting the new connection policy for some future year. Three variants to this baseline are developed representing differing assumptions regarding the realization of new transmission capacity. Finally four scenarios are developed representing differing assumptions regarding other impact factors. An overview of the scenarios considered is presented in Table 3.1. In the following, each of the scenarios and variants will be presented in some more detail.

Scenario 0: Limited Connection Policy

For the simulation of the benefits of the newly adopted connection policy a scenario was developed representing the temporary ad-hoc response of the TSO and DSOs adopting a limited-connection policy. This scenario distinguishes itself from the other scenarios in that it assumes no investment in generation capacity in the congestion areas Zuid-Holland (ZH) and the Northern part of the Netherlands (NN).

Table 3.1 *Overview of Scenarios*

	Limited connection policy	New connection policy				
	Scenario 0	Scenario A (Baseline)	Scenario B	Scenario C	Scenario D	Scenario E
Generation investment [limited; moderate; high]	limited	moderate	*low*	moderate	moderate	moderate
Wind availability [moderate; high]	moderate	moderate	moderate	*high*	moderate	moderate
Secure transmission capacity at Northern German border [moderate; high]	moderate	moderate	moderate	moderate	*high*	moderate
CO_2 price [low; moderate]	moderate	moderate	moderate	moderate	moderate	*low*

On the other hand, investment plans for production capacity located at the ring (RN) and in Zeeland are considered however, following the Dutch national energy scenarios as presented in Daniels et al. (2009) updated with the latest insights regarding investments in production capacity.

Scenario A: Moderate Generation Investment (Baseline)

A baseline scenario was developed on the basis of Daniels et al. (2009), updated with the latest insights regarding investments in production capacity. The Dutch national energy scenarios entail an integral scenario analysis of the Dutch energy system for the purpose of ex-ante policy evaluations. As any other scenario, this scenario does not represent an expectation regarding generation investment, fuel prices, or any of the other assumptions. It does, however, represent a realistic future development of the Dutch energy system for the coming years.

The assumptions in Scenario A are largely in line with the reference scenario presented in Daniels et al. (2009) for the year 2015, representing a moderate growth of generation capacity in the Netherlands. Furthermore investments in transmission capacity are assumed to comprise of the planned expansion of transmission capacity between the Northern part of the Netherlands and the ring (NN-RN).[6] The values regarding the generation capacity investment, transmission capacity investments, demand, and fuel - and CO_2 prices assumed in the Baseline Scenario are presented in Appendix B.

As the assumptions regarding transmission investment in the Netherlands are a particularly important driver for congestion, a number of variants regarding the transmission investment assumption is considered as presented in Table 3.2. Scenario A assumes the southern section of the project Randstad 380 kV, increasing the transmission capacity between Zuid-Holland and the ring (ZH-RN), not to be realised yet. On the other hand it assumes the planned upgrade of the Vierverlaten-Zeijerveen-Hoogeveen route to be in place and as such assumes an increase of the transmis-

[6] The assumptions regarding investment in generation capacity in the Netherlands and the realization of transmission capacity investment plans may largely be taken to be in line with the assumptions for the second quarter of 2012 as laid down in the assumptions presented in the 'Tool vermogentransport Maasvlakte' and 'Tool vermogentransport Noord-Nederland' at www.tennet.org.

sion capacity of the transmission capacity between the Northern part of the Netherlands and the ring (NN-RN).

Table 3.2 *Variants to the Baseline Scenario reflecting differing assumptions regarding realization of transmission expansion prior to or after generation capacity expansion*

Scenario	Description	Realization of transmission capacity investment plans	
		NN-RN	ZH-RN
Scenario A	Vierverlaten-Zeijerveen-Hoogeveen	pre-investment	post-investment
Scenario A1	Neither	post-investment	post-investment
Scenario A2	Both	pre-investment	pre-investment
Scenario A3	Southern section Randstad 380 kV	post-investment	pre-investment

In order to assess the impact of the realization of transmission capacity investment on congestion in the Northern part of the Netherlands and Zuid-Holland several variants to the Baseline Scenario were established. Table 3.2 presents an overview of these variants. Here, the variants are distinguished by the fact that realization of transmission investment plans occurs before (pre-investment) or after (post-investment) the assumed investment in generation. The corresponding parameter values which are varied in these scenarios are presented in Appendix B.

Scenario B: Low Generation Investment
In comparison to Scenario A (Baseline), this scenario assumes somewhat lower generation investments.

Scenario C: High Wind
This scenario assumes a higher than average wind availability, in contrast to Scenario A (Baseline). Within the modelling framework of COMPETES, such an assumption is not distinguishable from increased capacity of wind turbines, so that the scenario could also be taken to represent increased investment in wind turbines.

Scenario D: High NTC at Northern German Border
This scenario assumes an increased net transfer capacity between Northern Germany and the Northern part of the Netherlands in comparison to the baseline.

Scenario E: Low CO2 price
In this scenario the CO_2 price is assumed to be relatively low at 20 €/tonne, in contrast to the CO_2 price assumption applied for Baseline that sets the CO_2 price at a moderate 35 €/tonne. CO_2 prices have a significant impact on the equilibrium prices and import/export flows between the Netherlands and Germany.

4. Net Benefits of the New Connection Policy

This chapter presents results for the benefits associated with the new grid connection policy under a variety of scenarios. It is assumed that the newly adopted grid connection policy will result in additional investments in generation capacity in comparison to the former temporary ban on new grid connection. The additional investments in generation capacity may reduce average marginal and total cost of production for the Dutch power system. Conceivably these developments result in lower prices on the Dutch wholesale market affecting both consumer and producer benefits. On the other hand, in case internal transmission capacity is not sufficient, an increase in generation capacity may lead to congestion within Netherlands. To resolve congestion, redispatch of production from congestion- to non-congestion areas is required. This redispatch implies a transfer of production from low-cost facilities in congestion regions to higher-cost facilities in non-congestion regions, resulting in an increase of total production cost in comparison to the preceding original dispatch. Therewith, the reduction of total production cost due to new generation capacity may be reduced by the associated redispatch costs.

This chapter presents an assessment of the benefits of potential new investments in generation capacity in the Netherlands resulting from the new connection policy and the corresponding redispatch costs, based on the scenarios presented in Chapter 3. None of the results on either the benefits or the redispatch costs presented in this chapter can be interpreted as a forecast or expectation value for the near future. Moreover, the range of benefits or the redispatch costs presented does not represent uncertainty regarding future benefits or redispatch costs. The absolute values of both the benefits and the redispatch costs only reflect the underlying scenario assumptions with respect to supply and demand developments, fuel - and CO_2 prices and the transmission capacity of the Dutch network. Finally, and accordingly, it should be emphasised that the benefits should be considered in conjunction with the associated redispatch costs and the results do not support combination of benefits resulting from one scenario with the redispatch costs resulting from another. The results presented in this chapter are derived under a variety of scenarios in order to give an indication of the robustness of the proportion of the benefits and the redispatch costs with respect to the variation of several of the main determinants as reflected in the underlying scenario assumptions.

In Section 4.1 the assessment of the benefits of the new connection policy is presented, whereas the assessment of redispatch costs is presented in Section 4.2.

4.1 Benefits of the New Connection Policy

This section presents simulation results regarding the potential benefits of the new connection policy. Here benefits are considered to be reflected in the simulated changes of the average yearly baseload prices, the yearly net exports, the producers' yearly gross margin and yearly consumer surplus resulting from each of the relevant scenarios in comparison to the limited connection policy scenario.

Here dispatch results, i.e. the results that disregard potential internal congestion, are compared as these results reflect the maximum achievable benefits. In other words, all simulations assume no internal congestion to occur. From a modelling perspective, this assumption is implemented by application of the single-node network representation of the Dutch network.

The relevant scenarios within the context of this assessment involve Scenarios A to C and Scenario E. As far as the benefits for dispatch are concerned, Scenarios A1-A3 are indistinguishable from Scenario A, as these variants only differ in domestic transmission capacity which is disregarded in the dispatch evaluation. Also, Scenario D results in identical benefits as Scenario A, since dispatch results are determined by changes in operational transmission constraints rather than changes in the secure cross-border transmission capacity. Scenario A and B are discussed in Section 4.1.1, while scenario C and E are presented in Section 4.1.2 and 4.1.3 respectively.

4.1.1 Benefits under low and moderate generation investment assumptions

In this section, the impact of differing scenarios for generation capacity investments in the Netherlands on the simulated benefits for consumers and producers are assessed. The assessment is based on the comparison with the results of the limited connection policy scenario.

In Table 4.1 several key results for the simulated Dutch market equilibriums in case of both limited connection policy and the new connection policy are presented. In the latter case, results for both the low and moderate generation investment scenarios (Scenario A and B) are presented. In both instances of the new connection policy, the additional new generation capacity implies a significant increase of the baseload capacity. As a result, the wholesale prices for power are depressed somewhat and Dutch power becomes increasingly competitive in comparison to power generated in neighbouring markets. In response to the price decrease, Dutch consumption increases somewhat, as a consequence of price-elasticity of demand. Furthermore, the Netherlands results to be a net importing country in case of the limited connection generation, whereas net exports result with the additional new generation capacity under the new connection policy. Finally, the wholesale prices in the Netherlands go down as more generation capacity is connected to the grid.

In Table 4.2, derived benefits of the new connection policy are presented, both for the case of low and moderate generation investment. Here the benefits are derived as changes in total yearly generation costs, producers' gross margin and consumer surplus for these scenarios in comparison to the limited connection policy scenario. The total generation costs increase due to the increase of generation in the Netherlands. Total producers' gross margin increase due to both the increase in exports and the higher margins that result for the new low-cost baseload facilities during peak hours. Due to the decrease in wholesale power prices, consumer surplus increases as well. Total benefits, derived as the sum of the yearly producers' gross margin and consumer surplus, increase accordingly.

Table 4.1 *Key simulation results on the Dutch wholesale market assuming limited connection and the new connection policy with low and moderate generation investment*

			New connection policy	
		Limited connection policy	Moderate generation investment	Low generation investment
Scenario		0	A	B
Total generation capacity	[GW]	21.0	30.0	26.7
Generation	[TWh]	107.7	144.6	133.3
Consumption	[TWh]	111.8	113.3	112.6
Net imports	[TWh]	4.1	-31.3	-20.7
Average yearly baseload price	[€/MWh]	57.5	53.9 (-%6)	55.6 (-%3)

Table 4.2 *Benefits of the new connection policy for both low and moderate generation investment assumptions*

Scenario		Moderate generation investment A	Low generation investment B
Δ Generation costs	[mln €/yr]	1308	932
Δ Producers' gross margin	[mln €/yr]	287	290
Δ Consumer surplus	[mln €/yr]	357	188
Δ Total benefits	[mln €/yr]	644 (+%35)	478

Additions to generation capacity may also affect the import and export flows. Figure C.2 and Figure C.3 in Appendix C present the exchanges of power between the Netherlands and the neighbouring countries under the limited connection policy assumptions and the two new connection policy scenarios considered here. On the basis of the results presented in Appendix C it may be concluded that the exports from the Netherlands to the neighbouring countries increase with increasing production capacity.

4.1.2 Benefits under moderate and high wind assumptions

An average winter availability of 45% for offshore and 36% for onshore wind is assumed in Scenario A. In Scenario C we assume average winter availability of 60% for offshore wind and 45% for onshore wind in the Netherlands and the neighbouring countries. As a result, the wind power production increases by roughly 30% in Northwest European countries (the Netherlands, Germany, UK, Belgium, and Norway).

When comparing Scenarios A and C, in Table 4.3, increased wind production does not show to have a significant impact on the equilibrium prices or any of the other simulation results presented. This may be understood upon further analysis of Dutch supply and demand under both moderate and high wind assumptions. Figure 4.1 compares the simulated supply curve for the Dutch power system during the winter, both in case of the moderate and high wind production scenarios. The vertical curves in the figure represent national demand plus net exports on an average winter peak - and winter off-peak hour. It may be observed that equilibrium for winter peak - and off-peak hours is established essentially on an extensive plateau of the Dutch supply curve. If wind power generation increases with 30%, the Dutch supply curve expands as indicated. Both for winter peak - and winter off-peak equilibrium is effectively established on the same plateau of the supply curve however. Hence, the difference between the equilibrium prices resulting from Scenario A and C is relatively small. The exchanges resulting from increased wind power production the North-West European countries in Scenario C (See Figure C.4 in Appendix C) are observed to be very similar to the exchanges in Scenario A.

Table 4.3 *Key simulation results on the Dutch wholesale market assuming moderate and high wind respectively*

		Moderate wind	High wind
Scenario		A	C
Total generation capacity	[GW]	30.0	30.0
Generation	[TWh]	144.6	145.0
Consumption	[TWh]	113.3	113.3
Net imports	[TWh]	-31.3	-31.7
Average yearly baseload price	[€/MWh]	53.9 (-%6)	53.9 (-%6)

Table 4.4 *Benefits of the new connection policy for both moderate and high wind assumptions*

		Moderate Wind	High Wind
Scenario		A	C
Δ Generation costs	[mln €/year]	1308	1230
Δ Producers' gross margin	[mln €/year]	287	379
Δ Consumer surplus	[mln €/year]	357	361
Δ Total benefits	[mln €/year]	644	730 (+%13)

In Table 4.4, the resulting benefits are presented. Producer gross margin and consumer surplus differences between limited generation scenario on the one hand and the moderate and high wind generation scenarios on the other are reported. The results indicate that the increase in wind power production has a positive impact on the benefits of the generators. Due to the increase in wind power production, the overall generation costs decrease and overall producer gross margin increases. Here the increase in producer gross margin mainly involves an increase for the wind power producers, at cost of other generators in the Netherlands. The consumer surplus increases slightly due to the price decreases observed in the Netherlands.

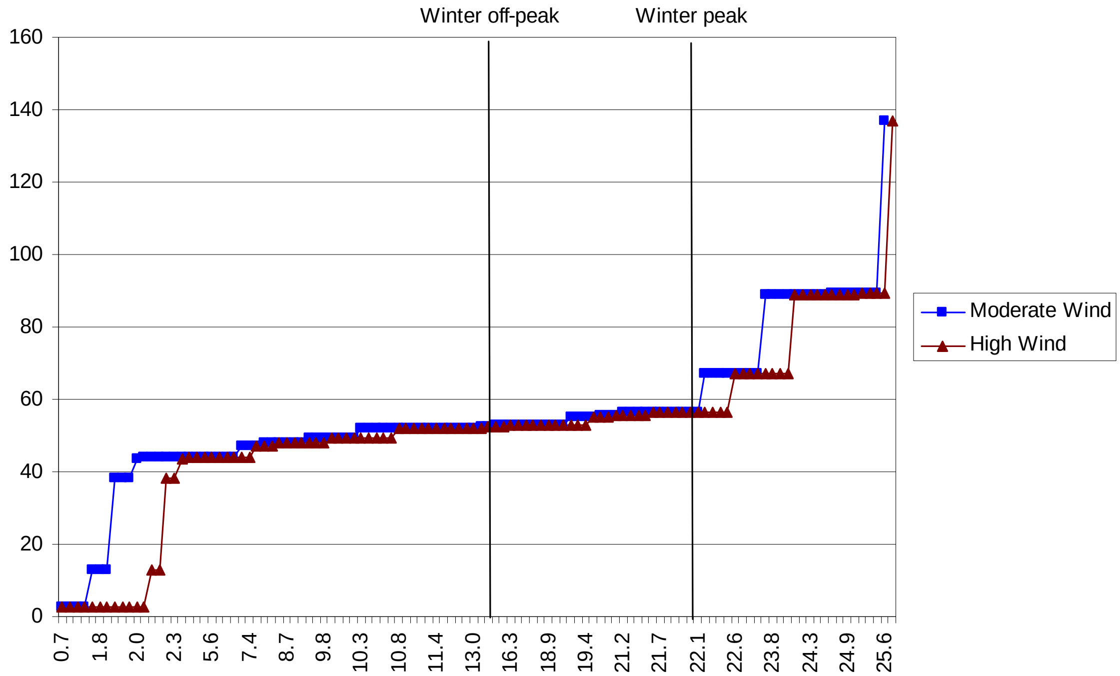

Figure 4.1 *Simulated supply curve in the Netherlands for the moderate (Scenario A) and high wind power generation (Scenario C) scenarios*

4.1.3 Benefits under low and moderate CO_2 price assumptions

The CO_2 price is established on the market for European emission allowances under the European Union Emission Trading Scheme (EU ETS). The CO_2 price is the outcome of a cap-and-trade system, which requires a variety of European industries to purchase permits to discharge CO_2 while placing a strict limit on the available permits.

The Baseline Scenario assumes a moderate CO_2 price of 35 €/tonne and this assumption was applied in the previous sections as well. In this section, we will analyse the impact of a moderate increase in generation capacity in the Dutch system under the assumption that the CO_2 price remains at the relatively low level of 20 €/tonne. This latter assumption may be interpreted as a reflection of the currently observed price levels for CO_2 due to the lower demand for the permits as a result of the economic crisis.

Table 4.5 indicates that, as a result of additional generation capacity under the low CO_2 price assumption, the average baseload price in the Netherlands is reduced quite significantly in comparison to the limited connection policy. Dutch consumption therefore increases somewhat, in accordance with the price-elastic response of demand, and also the Dutch exports increase. These observations are in line with the results observed under the moderate CO_2 price assumption, with the same increase in generation capacity in the Netherlands (Scenario A). However if we compare the results for Scenario A and E, in Table 4.1 and Table 4.5 respectively, the wholesale price for the low CO_2 price scenario results to be lower than the wholesale prices for the moderate CO_2 price scenario. This is the result of the decrease of marginal cost of all fuel-based generation units due to the decrease of the costs associated with the CO_2 emission. Furthermore, the moderate CO_2 price scenario has a much higher impact on Germany's carbon-intensive power production system so that Dutch exports increase much stronger for the moderate CO_2 price assumption. Figure C.5 in Appendix C indicates the resulting exchange flows for Scenario E.

Table 4.6 presents the difference in benefits of the moderate increase of generation capacity in the Netherlands both assuming moderate and low CO_2 prices, in comparison to the limited connection policy. In both scenarios, connecting additional generation capacity is beneficial for the generators and the consumers. In low CO_2 price scenario, the benefits of the Dutch generators are higher due to the lower emission costs. The benefits of consumers in low CO_2 price scenario are also higher due to the lower wholesale prices.

Table 4.5 *Key simulation results on the Dutch wholesale market assuming low and moderate CO_2 prices*

		Limited connection policy	New connection policy
Scenario		0	E
Total generation capacity	[GW]	21.0	30.0
Generation	[TWh]	90.8	118.3
Consumption	[TWh]	114.7	116.2
Net imports	[TWh]	24.0	-2.1
Average yearly baseload price	[€/MWh]	50.1	46.1(-%8)

Table 4.6 *Benefits of the new connection policy for both moderate and low CO_2 price assumptions*

Scenario		Moderate CO_2 price A	Low CO_2 price E
Δ Generation costs	[mln €/yr]	1308	510
Δ Producers' gross margin	[mln €/yr]	287	372
Δ Consumer surplus	[mln €/yr]	357	400
Δ Total benefits	[mln €/yr]	644	772

4.2 Redispatch Costs associated with the New Dutch Connection Policy

This section presents the redispatch costs associated with the benefits derived in the previous sections. The results are derived by first simulating the market equilibrium for each of the scenarios considered assuming no internal transmission limits in the Netherlands, i.e. dispatch as it would result from trading disregarding potential congestion, followed by a simulation including domestic transmission limits. From a modelling perspective, the former simulations involve a simulation with a single-node network representation of the Dutch network, whereas the latter involve a simulation with a multi-node representation of the Dutch network. The former can not result in any congestion for the Dutch network, whereas the latter simulations may result in the occurrence of congestion in the Dutch network. If congestion occurs in the latter simulation, the highest-cost dispatched plants in the congestion region are taken out of dispatch while the least-cost non-dispatched capacity in the non-congestion regions is dispatched in order to cover for the loss of production. Redispatch costs then involve total cost of production of the plants that are decommited minus total cost of production of the plants that are dispatched to cover for the loss of production volume. The computational evaluation of this equilibrium intrinsically assumes efficient redispatch and therefore indicates the least-cost solution for redispatch.

As before, it should be emphasised that none of the results on the redispatch costs presented in this chapter can be interpreted as a forecast or expectation value for the near future. Neither does the range of redispatch costs represent uncertainty regarding future benefits or redispatch costs. The absolute values of the redispatch costs only reflect the underlying scenario assumptions with respect to supply and demand developments, fuel - and CO_2 prices and the transmission capacity of the Dutch network. Moreover, each of the redispatch costs evaluations should be seen against the background of the associated benefits derived in the previous sections. Therefore, the redispatch costs are presented in association with the associated benefits, as derived in the previous sections.

In the following the resulting redispatch costs for the various scenarios are presented. Here, results are presented for differing assumptions regarding realization of transmission investments in the Netherlands in Section 4.2.1, since these assumptions have a significant impact on the level of congestion and resulting redispatch costs. The differing realizations of transmission investment are represented by the variants for scenario A, scenarios A1 to A3. Furthermore the redispatch costs associated with the benefits resulting for the scenarios A to E are presented in Section 4.1.2.

4.2.1 Redispatch Costs under varying Domestic Transmission Capacity Investments

The increase in congestion and associated redispatch costs due to potential increases in generation capacity in the Netherlands will depend heavily on the development of new domestic transmission capacity. Therefore several synthetic variants of the baseline scenario (Scenario A) were established, reflecting differing assumptions with respect to the development of new domestic transmission capacity, as laid down in Scenario A and its variants, A1 to A3. The baseline and its variants represent differing assumptions regarding realization of transmission investments between the Northern provinces and the ring (NN-RN) on the one hand and Zuid-Holland and the ring on the other (ZH-RN) as described in Section 3.3.

Table 4.7 presents the results for the four transmission investment variants, assuming moderate investment in generation. In all cases benefits result offer benefits of some 644 mln €/year, conform the results presented in Section 4.1.1. Variant A1 represents the case that neither of the investment plans for transmission expansion is realized by the time the generation investments assumed in Scenario A are realized. This scenario results in relatively high redispatch costs, in the order of 79.14 mln €/year, and both trajectories result to be congested more than 75% of the time. If on the other hand, the transmission capacity investment plans in both regions are realized, as assumed in Variant A2, congestion and the corresponding redispatch costs are virtually absent. Any internal transmission capacity investment scenario between these extreme scenarios (ceteris paribus), e.g. Scenario A and Variant A3, would lead to intermediate levels of congestion and associated redispatch costs.

For each of these transmission investment variants, the benefits resulting from the assumed investments in generation are significantly higher than the associated redispatch costs. Even under the extreme assumption that none of the planned transmission capacity expansions is in place by the time generation investments are realised, the total benefits result to be roughly an order of magnitude larger than the associated redispatch cost.

Table 4.7 *The impact of realized transmission capacity investments on the redispatch costs*

	Transmission Capacity [MW]		Redispatch Costs [mln €/y]	Benefits [mln€/yr]
	NN-RN	ZH-RN		
Scenario A (Baseline)	4170	2600	46.96	644
Scenario A1	2670	2600	79.14	644
Scenario A2	4170	5800	<0.003	644
Scenario A3	2670	5800	6.31	644

4.2.2 Scenario Analysis of the Redispatch Costs

In this section congestion and redispatch costs in the Netherlands for Scenarios A to E are presented. The resulting congestion and redispatch costs are presented in Table 4.8. The redispatch costs are mainly driven by the redispatch volume, i.e. the volume of production that needs to be reallocated from the congestion regions to the non-congestion regions, and the difference between the marginal production costs in congestion and the non-congestion regions.

As the transmission investments assumed in all scenarios involves investment in additional transmission capacity between the North of the Netherlands (NN) and the ring (RN), congestion from the Northern part of the Netherlands is relatively low in all scenarios in comparison to congestion in Zuid-Holland. An interesting observation here is that although congestion is observed from the Northern Netherlands to the Ring after redispatch in some periods in Scenarios A and B, there is no redispatched production from the Northern Netherlands. This can be explained as follows: original dispatch of production, i.e. before redispatch, in the Northern part of the Netherlands does not cause congestion since the transmission capacity assumed from the Northern Netherlands to the Ring in Scenarios A-E is sufficient. However, to redispatch the production capacity in Zuid-Holland the production in the Northern Netherlands is increased as well as the production in the Ring. The production from the Northern Netherlands is increased until available transmission capacity in this region and hence it is congested after redispatch.

Table 4.8 *Scenario-based Redispatch Costs in the Netherlands*

Scenarios		Congestion [% of the time]		Redispatch Costs [mln €/yr]	Benefits [mln €/yr]
		From NN	From ZH		
A	Moderate Generation Investment	10	68	46.96	644
B	Low Generation Investment	8	59	30.11	478
C	High Wind	18	68	36.02	730
D	High Secure Transmission Capacity at Northern German Border	10	68	46.96	644
E	Low CO_2 price	24	43	29.03	772

Redispatch Costs under low and moderate generation investment assumptions

In Table 4.8 it is shown that both the redispatch costs and the benefits for the low generation investment scenario (Scenario B) are lower than in case of the moderate generation investment scenario (Scenario A), as may be expected. In addition, however, one may observe that Scenario A and Scenario B do show a similar congestion pattern. Figure C.6 in Appendix C shows the congestion pattern in the Dutch grid and the international exchanges after redispatch in both the moderate and low generation investment scenarios in some more detail. In both instances, the transmission capacity between Zuid-Holland (ZH) to the ring (RN) is congested more than 50% of the time, whereas the transmission capacity between the Northern Netherlands (NN) and the ring (RN) is congested less than 25% of the time in a year. This pattern mainly results from the assumption that the transmission capacity investment in the NN-RN link is realized whereas the investments in the ZH-RN are not. Hence, the resulting redispatch costs are mainly driven by the congestion between Zuid-Holland (ZH) and the ring (RN).

Redispatch Costs under moderate and high Wind Assumptions

The impact of increased wind power production North-western Europe on congestion and redispatch costs for the Dutch system may be assessed by comparison of the results for Scenarios A and C in Table 4.8. With higher wind power generation the congestion between the Northern part of the Netherlands (NN) and the ring (RN). As far as redispatch costs are concerned, two opposing effects can be observed. Firstly total redispatch costs increase with increasing congestion. Secondly, the increased levels of wind power production displace relatively low-cost thermal generation capacity, so that these facilities result to be extramarginal. In case redispatch is required these facilities are available for redispatch so that total costs of production of the newly committed generators, and thus total redispatch costs, are reduced somewhat in comparison Scenario A. This effect is a direct consequence of the assumed structure of the Dutch supply curve.[7] An illustration hereof can be observed in Figure 4.1. Here one may observe that the marginal costs of the residual capacity in case of winter peak demand are reduced in case of high wind power generation. The second effect dominates the first one in Scenario C, so that lower redispatch costs result for this scenario in comparison to Scenario A.

If we compare Scenario C in Figure C.7 of Appendix C with Scenario A in Figure C.6 of Appendix C, transmission from Northern Germany to the Northern part of the Netherlands increase due to higher wind production in Germany. As a result this interconnection becomes increasingly congested. However, the increased imports do not have a significant impact on the congestion between the Northern part of the Netherlands (NN) and the ring (RN).

Redispatch Costs under increased NTC assumptions at the Northern German Border

Table 4.8 indicates that the increase of physical available capacity between the Northern Germany to the Northern Netherlands does not have a significant impact on the congestion and the redispatch costs within the Netherlands. This result is mainly due to fact that the Netherlands is a net exporting country to Germany in Scenarios A and D.

Redispatch Costs under low and moderate CO2 price Assumptions

In low CO_2 price scenario in Table 4.8, redispatch cost decreases significantly. This is both due to the decrease in congestion in ZH and the decrease in the difference between the marginal generation costs in congested and the non-congested areas. For instance when CO_2 price is low, the difference between the marginal cost of an efficient gas unit in congested area and a less efficient gas unit in non-congested area is lower. Hence, the redispatch cost of these units is also lower.

Comparing Scenarios A and E in Figure C.6 and Figure C.8 respectively given in Appendix C, one can see the impact of CO_2 price on the congestion pattern in Dutch grid. In low CO_2 price scenario, the Netherlands is exporting more from Germany; hence the congestion from the Northern Germany to the Northern Netherlands (NN) increases. This also increases the congestion between NN and the ring (RN). In addition, the gas-based generation units in Zuid-Holland (ZH) are less competitive against coal-based generation units in other regions including Germany. Hence, the congestion from ZH to RN decreases due to the decrease in generation in ZH under low CO_2 price assumption.

[7] This effect is a direct consequence of the assumed structure of the Dutch supply curve. An illustration hereof can be observed in Figure 4.1 in Section 4.1.2. Here one may observe that the marginal costs of the residual capacity for winter peak demand are reduced in case of high wind power generation.

4.3 Conclusions

The results presented in this chapter indicate that the additional generation capacity that may be expected to come online as a result of the new connection policy is beneficial for both consumers and (baseload) producers. However, an increase in generation capacity may result in congestion. The resulting congestion will need to be resolved through redispatch. With redispatch, redispatch costs will arise associated with the reallocation of generation capacity from constrained areas to non-constrained areas. Hence, the total benefits may be hampered by the associated redispatch costs.

In all evaluations total benefits of the new connection policy are significantly higher than the re-dispatch costs. Even under the assumption that no additional investments in transmission are realized before the generation capacity expansion is realized, total benefits of the new connection policy are well above the associated redispatch costs. The absolute value of benefits and costs will be dependent on the supply, demand, and fuel and CO_2 price developments; however essentially the benefits are shown to be roughly an order of magnitude higher than the redispatch costs so the conclusion is expected to be robust.

On the other hand one should note that all the redispatch costs in this chapter are calculated based on the assumption of efficient dispatch. Inefficiencies in redispatch, potentially caused by the congestion management system may lead to an increase in the redispatch costs. In addition, the simulations assume no spill-overs from the congestion management system into the wholesale market.

5. Analysis of Congestion Management under Non-Strategic Behaviour

This chapter analyses the welfare effects of a subset of congestion management systems as presented and described by Hakvoort et al. (2009), assuming no strategic behaviour of the participants. In addition, this analysis assumes efficient redispatch in the sense that a least-cost solution of redispatch is realized.

The analysis is based on the baseline Scenario, Scenario A. One should note that this Scenario does not represent the expected developments over the course of the coming years. Among the four scenarios of the realization of transmission capacity investment plans discussed in the previous chapter, Scenario A results in moderate though significant congestion. The alternative scenarios result either in no or low levels of congestion or in very high levels of congestion. The associated redispatch costs for these scenarios would therefore be zero, low or very high respectively due to the non-linear structure of the high end of the supply curve. Hence, the internal transmission capacity assumption in Scenario A is assumed in this chapter for the purpose of comparing the impact of the congestion management systems considered on the distribution of costs and benefits. As this analysis is based on a single and synthetic scenario, the results presented in this analysis do not serve as indicate an expectation value of redispatch cost or the resulting costs and benefits for the different market agents. Rather the results in this scenario serve to identify how distribution of costs and benefits are affected by the different congestion management systems.

In the following, a brief introduction to congestion management is presented in Section 5.1. The evaluation of the differing congestion management systems is presented in Section 5.2 to 5.5, while conclusion regarding this analysis is presented in Section 5.6.

5.1 Congestion Management

Already since the early days of central planning, transmission limitations have called for congestion management procedures in order to resolve expected congestion in the transmission network. In those days short term scheduling of generation facilities in a control area would be resolved through cost minimization procedures on the basis of integrated unit commitment and dynamic economic dispatch, such that overall production costs would be minimized. In the event of potential violation of transmission limitations, this would either be addressed integrally within the optimisation procedure or be solved through secondary redispatch procedures.

The resulting least-cost solution involves an optimal dispatch of generation facilities such that overall production costs are minimized while the transmission limits are respected. With respect to the original dispatch solution, the redispatch solution can be characterized as a least-cost solution where the scheduled facilities with the highest marginal cost of operation in the congestion region are taken out of the schedule up until the transmission limits are no longer violated. In order to compensate for the reduction of scheduled power production, the least-cost facilities with excess capacity in the non-congested areas are dispatched as well. Total *redispatch costs* then amount to, and are defined as, the operational cost of the newly dispatched generation facilities minus the operational costs of the facilities that are unscheduled in the congestion area.

With the introduction of power markets in the past decades, a comparable procedure was commonly applied for congestion management. The procedure is generally referred to as redispatch and counter-trading, or simply system redispatch. In this case, the highest-cost generators in congestion areas are *constrained off*, i.e. are required to reduce their output. Meanwhile the least-cost generators in non congestion areas are asked to increase output or *constrained on*, so that the loss of volume in the congestion region is compensated while transmission limits are in contrast respected.[8] As in the case of central planning, total operational costs of the system increase with the redispatch costs. If one assumes competitive power markets and efficient allocation, one may note that social welfare then is reduced with the redispatch costs. In case of congestion management in the Netherlands, consumers are not to be burdened with direct costs of the congestion management system; instead, generators will be required to cover the redispatch costs. Consumers will therefore not be directly affected in the proposed congestion management schemes except for the indirect effect of lower prices as discussed in the previous chapter. As a consequence, not social welfare, but just the total surplus of generators and TSO combined is reduced with the redispatch costs. Any of the congestion managements systems considered therefore implies a reduction of overall surplus of generators and TSO with redispatch costs. Remaining differences between the congestion management systems only involve distributive effects.

In this chapter the welfare impacts of the redispatch models discussed in Chapter 2 as described by Hakvoort et al. (2009) will be analysed on the basis of the simulation results for the various Scenarios introduced in Chapter 3. Because of the underlying assumptions in Scenarios A to D, the redispatch costs are mainly due to the congestion in Zuid-Holland; that is only power in Zuid-Holland is constrained off for these Scenarios. An interesting observation is that although some congestion is observed from the Northern Netherlands to the Ring after redispatch, there is no redispatched production from the Northern Netherlands. This can be explained as follows: dispatched production (before redispatch) from the Northern Netherlands does not cause congestion since the transmission capacity assumed in Scenario A from the Northern Netherlands to the Ring is sufficient. However to compensate the constrained off generation in Zuid-Holland, the production in the Northern part of the Netherlands is also increased, besides the production in the Ring, until available transmission capacity from the Northern part of the Netherlands to the Ring. Hence, the Northern part of the Netherlands is congested after redispatch. This phenomenon of a non congestion area before redispatch becoming a congested area after redispatch may be observed in any meshed network. Nevertheless whether the production in Zuid-Holland or the Northern Netherlands is redispatched as a result of limited transmission capacity, the distributive effects of redispatch costs among constrained off units, non constrained off units, and TSO will remain robust under the four proposed congestion management systems.

In each of the following sections one of the redispatch models considered is briefly introduced according to the description of Hakvoort et al. (2009). The description is followed by a presentation of any additional assumptions introduced for the purpose of simulation of the welfare effects of the congestion management model. For each of these congestion management models, the impact on yearly surplus of both generators and TSO has been derived from the simulations that were performed with COMPETES.[9]

[8] For further details see Hakvoort et al. (2009)

[9] The calculation of benefits only considers short-run marginal cost of operational and disregards capital expenditures (CAPEX) associated with generation capacity. Technically speaking, surplus for generators should account for investments costs associated as well. As the analysis is only concerned with the difference in surplus between dispatch and redispatch, the CAPEX does not affect the results as investment costs are identical for dispatch and redispatch.

5.2 System Redispatch Model with Cost Pass-Through to Generators

5.2.1 Brief Description

System redispatch with cost pass-through to generators replicates the general system redispatch, but accounts for additional arrangements to pass-through the redispatch costs to the generators.

The TSO organizes a market for both constrained off services and constrained on services. The constrained off market involves a single-sided bidding market for production obligations. Bids from generators in congestion areas reflect the price they are willing to pay to the TSO for transferral of their production obligation to the TSO. It is assumed that bidding behaviour of the generators is aimed at maintaining the same profits as expected in case the generators are not constrained off. As the generator already received payment for the production obligation, the generator would then be willing to pay its marginal cost of production so that the expected profits are prevented from changing. The constrained off market is proposed to involve a centralized market, organized by the TSO, with a pay-as-bid pricing structure.[10] The TSO, seeking to receive the highest payments for accepting the production obligations, accepts the highest bids from the constrained off generators. The remaining producers, which are the non-constrained off producers in the congestion area, will generally have marginal costs of production at somewhat lower levels than the market price.

In order to source it's newly acquired production obligations the TSO will need to contract compensatory power in non-constrained regions. To this end a centralized market to be organized by the TSO is proposed, again involving single-side bidding with a pay-as-bid pricing structure. In this market generators with non-dispatched capacity are expected to offer production. The congestion management model assumes competitive behaviour of the generators, so that bids will reflect marginal cost of production. These marginal costs will be higher than the market price as this capacity would otherwise already have been contracted in the power market.

The proposed system redispatch with cost pass-through assumes pass-through via a congestion fee set by the total redispatch costs divided by the total non-constrained off production in the congestion area. Therewith redispatch costs are allocated to the generators in the congestion area that are not constrained off.

5.2.2 Assumptions

The congestion model description by Hakvoort et al. (2009) assumes a binary network system with only one congestion region and one non congestion region. The nodal decomposition of the Dutch network applied for the representation of the Dutch power system involves four nodes, among which multiple nodes may show congestion or offer constrained on power.

For the purpose of the welfare calculations it is assumed that for each congestion region a nodal congestion fee applies. The nodal congestion fee is based on the node-specific redispatch costs, defined by the volume-weighed cost of constrained on power minus the avoided costs of constrained off power in this node.

[10] In contrast to a uniform pricing structure, where all accepted bids are cleared at a uniform market price, a pay-as-bid auction is characterized by the payment structure where each accepted bid is cleared against the price level of the bid.

5.2.3 Simulation Results

The simulation results for the system redispatch with costs pass-through to generators as applied to the simulation of the Dutch power system for Scenario A (Moderate generation Investment) are presented in Table 5.1. In this table the resulting yearly generator surplus in each of the regions distinguished is presented. The generator surpluses are differentiated for the constrained off (C_{off}), non constrained off (non C_{off}) and constrained on (C_{on}) generators. The national surplus, TSO surplus, total redispatch costs, and the change of surplus as a percentage of the redispatch costs (RDC) are presented as well.

As mentioned before, power in Zuid-Holland is constrained off for this Scenario. Table 5.1 indicates that the constrained off generators in Zuid-Holland face some loss of surplus, as their joint production is only partially constrained off. The resulting congestion fee affects the surplus of their remaining joint production and 22% of their surplus per year is lost accordingly. Analogously, the non-constrained off generators lose a significant proportion of their surplus due to the congestion fee, reducing their surplus 20% per year.

As may be expected, the TSO remains unaffected by this scheme, since the TSO compensates the difference between revenues from taking on production obligations from the constrained off generators and the costs of purchase of compensatory power from the constrained on generators through the congestion fee.

Table 5.1 *Yearly surplus simulations for system redispatch model with cost pass-through to generators for Scenario A*

	Dispatch	Redispatch	Delta	
	[mln €/yr]	[mln €/yr]	[mln €/yr]	[% of RDC]
Surplus Gen NN	431.68	431.68	0.00	0
NN C_{off}	0.00	0.00	0.00	0
NN non C_{off}	0.00	0.00	0.00	0
NN C_{on}	0.00	0.00	0.00	0
Surplus Gen RN	451.65	451.65	0.00	0
RN C_{off}	0.00	0.00	0.00	0
RN non C_{off}	0.00	0.00	0.00	0
RN C_{on}	0.00	0.00	0.00	0
Surplus Gen ZH	305.24	258.28	-46.96	-100
ZH C_{off}	21.59	17.06	-4.45	-9
ZH non C_{off}	207.79	165.36	-42.51	-91
ZH C_{on}	0.00	0.00	0.00	0
Surplus Gen ZL	165.89	165.89	0.00	0
ZL C_{off}	0.00	0.00	0.00	0
ZL non C_{off}	0.00	0.00	0.00	0
ZL C_{on}	0.00	0.00	0.00	0
Surplus TSO	0.00	0.00	0.00	0
Surplus Gen NL	1354.46	1307.50	-46.96	-100
Total Surplus	1354.46	1307.50	-46.96	-100
Redispatch Costs			46.96	

No additional surplus results from the congestion management scheme for the constrained on generators, as the pay-as-bid pricing structure combined with competitive bidding assures no surplus results for the constrained on transactions. Finally, it may be observed that total change in surplus of the system is equivalent to the total redispatch costs amounting to 46,96 mln € yearly. Regarding the distributive effects of this scheme, the total redispatch costs are shared by the constrained off (due to their remaining generation) and the non-constrained off generators by 9% and 91% of the total redispatch costs respectively.

In Tables D.1, D.2 and Tables D.3, D.4 in Appendix D the simulation results for Scenarios B (Low Generation Investment) and C (High Wind) are presented. In both cases, overall redispatch costs decline as less congestion occurs. The distributive effects of the scheme are in line with the results for Scenario A.

5.2.4 Discussion

For the competitive evaluation, the system redispatch with cost pass-through to generators shows the lowest distributive effects of the four systems considered. As a centralized market with a single counter party, being the TSO, the proposed transaction costs are likely to be relatively low. Transaction costs for constrained off generators in this system will be limited in comparison to congestion management systems that require constrained off generators to purchase compensatory power in the market, like the market redispatch model and the market agent approach. For the same reason, the constrained on and - off market may be more accessible for small generators than for systems where no centralized market is organized. Furthermore this system neither leaves the consumers nor the TSO directly exposed. Finally this system is a classic redispatch system that relates to current practice and has been applied often before.

An important drawback of this system is that it gives the wrong signals for constrained off generators. Since constrained off generators are compensated for the loss of volume, it induces an incentive to become constrained off. For the long term, it may reduce incentives for decommissioning. It does not seem likely that it would induce incentives for investment in the congestion region as such decisions are not likely to depend on short-term systems that may change and that critically depend on a multitude of other considerations. It may be observed as well though, that this system does not reduce incentives for investment in congestion regions as much as some of the other systems do.

5.3 Market Redispatch Model

5.3.1 Brief Description

The market redispatch model assumes a reduction of volume in congestion areas according to bids of generators in a congestion rights market. Constrained off generators are required to purchase compensatory power in non congestion areas, whereas non-constrained off generators are required to pay a congestion fee set by the highest accepted bid for the congestion rights market.

The assignment of constrained off volume involves a single-side bidding procedure, where generators in congestion areas signal their respective expected cost of redispatch. For competitive bidding it is assumed that generators will bid in the expected cost of redispatch, i.e. the expected price of compensatory power minus the marginal cost of operation. The description of the market redispatch models in Hakvoort et al. (2009) does not disqualify an hourly auction, but a monthly auction is proposed as this would reduce the transaction costs for the generators significantly.[11]

A bid and its relative position in the resulting bid curve only determines the priority of constraining a particular unit off in the face of redispatch requirements where priority is given in the order of increasing bids, i.e. priority of redispatch is given to the units with the lowest expected redispatch costs. No payment is associated with the bid.

Once congestion occurs, the TSO assigns the necessary constrained off volume to the bids in order of increasing redispatch costs. Generators, whose bids are 'accepted', are selected to be constrained off. In addition, the highest bid accepted sets the marginal congestion price, or the congestion fee, which is charged to generators that are not constrained off.

The generators that are constrained off are obliged to contract compensatory power themselves, without any financial compensation. The constrained off generators are assumed to purchase compensatory power in non congestion areas to compensate for their loss of volume. No explicit market seems to be assumed here, but bilateral trading and uniform pricing is assumed.[12]

5.3.2 Assumptions

The congestion model description by Hakvoort et al. (2009) assumes a binary network system with only one congestion region and one non congestion region. The nodal decomposition of the Dutch network applied for the representation of the Dutch power system involves four nodes, among which multiple nodes may show congestion or offer constrained on power.

For the purpose of the welfare calculations it is assumed that for each congestion region a nodal congestion fee applies. The nodal congestion fee is based on the node-specific highest constrained off bid accepted.

[11] The claim that transaction costs for generators are particularly high for the market redispatch model is based on the assumption that compensating constrained on power in this model is contracted on a bilateral basis, in contrast to the system redispatch model and the hybrid redispatch model. See also Hakvoort et al. (2009).

[12] The schematic representation of the market redispatch model in Hakvoort et al. (2009) assumes the market price for constrained on volume in the non congestion region B to be the uniform extra marginal price in the non congestion region B. This is reasonable, since in a bilateral market, a low cost producer in the constrained on market has no incentive to contract to provide power at any price less than the cost of the highest cost constrained on generator. Under perfect information, all constrained on generators should get the same price for compensatory power within a given hour.

In order to simulate the welfare results for the market redispatch model an additional assumption is required regarding the bids of the generators in the congestion area. As indicated in the previous section, bids of generators in congestion areas are expected to reflect their respective costs of redispatch, set by the expected price of compensatory power in non congestion areas minus their individual marginal cost of operation. Assuming competitive offers and uniform pricing in non congestion areas, i.e. uniform pricing at marginal cost of production under redispatch in the non congestion areas, the price of compensatory power is set by the marginal bid of constrained on volume under redispatch.

For the purpose of the following welfare analysis efficient redispatch is assumed; that is, bids of constrained off generators are simulated by the marginal cost of production in the constrained on regions under redispatch minus the respective marginal cost of operation of the generators in the constrained off region. Hence it is assumed that all generators in the congestion areas are able to predict the marginal price of constrained on volume accurately.

5.3.3 Simulation Results

The simulation results for the market redispatch model in case of Scenario A (Moderate generation investment) as applied to the simulation for the Dutch power system are presented in Table 5.2. As before, the resulting yearly generator surplus in each of the regions distinguished is presented. The generator surpluses are differentiated for the constrained off (C_{off}), non constrained off (non C_{off}) and constrained on (C_{on}) generators. The national surplus, TSO surplus, total redispatch costs and the change of surplus as a percentage of the redispatch costs (RDC) are presented as well. Results are presented for both the case of sufficient transmission capacity (dispatch) and the case of insufficient transmission capacity (redispatch).

Table 5.2 *Yearly surplus simulations for the market redispatch model for Scenario A*

	Dispatch	Redispatch	Delta	
	[mln €/yr]	[mln €/yr]	[mln €/yr]	[% of RDC]
Surplus Gen NN	431.68	436.19	4.51	10
NN C_{off}	0.00	0.00	0.00	0
NN non C_{off}	0.00	0.00	0.00	0
NN C_{on}	0.00	4.51	4.51	10
Surplus Gen RN	451.65	474.99	23.34	50
RN C_{off}	0.00	0.00	0.00	0
RN non C_{off}	0.00	0.00	0.00	0
RN C_{on}	0.00	23.34	23.34	50
Surplus Gen ZH	305.24	-50.97	-356.21	-759
ZH C_{off}	21.59	-88.73	-110.25	-235
ZH non C_{off}	207.79	-38.10	-245.97	-524
ZH C_{on}	0.00	0.00	0.00	0
Surplus Gen ZL	165.89	168.13	2.24	5
ZH C_{off}	0.00	0.00	0.00	0
ZH non C_{off}	0.00	0.00	0.00	0
ZH C_{on}	0.00	2.24	2.24	5
Surplus TSO	0.00	279.16	279.16	594
Surplus Gen NL	1354.46	1028.34	-326.12	-694
Total Surplus	1354.46	1307.50	-46.96	-100
Redispatch Costs			46.96	

As in the system redispatch model, the constrained off generators in Zuid-Holland face loss of surplus, as their joint production is only partially constrained off. The resulting congestion fee in the market redispatch model decreases their surplus significantly more than any other system. Analogously, the non-constrained off generators lose a significant proportion of their surplus due to the high congestion fees that result in the market redispatch model in comparison to other redispatch models. For Scenario A, the congestion fee in the market redispatch model amounts to some €6/MWh on average per year, but may go up to levels of some €37/MWh during super peak in mid season.

In contrast to the case of system redispatch, that assumes a pay-as-bid pricing, this model results in an increase of surplus for the constrained on generators in the Northern Provinces (NN), Zeeland (ZL) and the ring (RN) due to the uniform pricing structure in market redispatch.

Again in contrast to system redispatch with cost pass-through, the distributive effects of this scheme are likely to be large. A significant decrease in the surplus of the non-constrained off generation in the congested area are observed, amounting to a change that is around seven times higher than the yearly redispatch costs. Furthermore, the TSO is heavily affected by this scheme. The TSO receives payments of congestion fees, but faces no additional costs so that a high increase of the surplus results, amounting to six times higher than the redispatch costs per year. Finally, as expected, it is observed that total change in surplus of the system is equivalent to the total redispatch costs amounting to €46,96 mln.

Tables D.1, D.2 and Tables D.3, D.4 of Appendix D, the simulation results for Scenario B (Low Generation Investment) and Scenario C (High Wind) are presented. The distributive effects for these scenarios of the scheme are in line with the results for Scenario A.

5.3.4 Discussion

For the competitive evaluation, the market redispatch shows the highest distributive effects of the four systems considered. Particularly the distributive effect of the congestion fee is significant, transferring a significant surplus for the non-constrained off generators to the TSO as congestion fees are set by the expected constrained on prices, resulting in relatively high congestion fees. An important effect of such high transfers of surplus is that generators in constrained off areas may run into losses so that the system renders some production facilities to be loss making. If these losses turn out to be systematic, one may expect these generators to stop offering their capacity in the wholesale market. This could drive up price levels in the wholesale market affecting consumer surplus. Effectively costs of redispatch then spill-over into the wholesale market and consumers are negatively affected indirectly. Further, this system offers no benefits for being constrained off so incentives are in line with the requirements, both for the short as for the long term. Finally in this system neither consumers nor the TSO directly exposed.

Assuming a monthly auction for congestion rights in order to keep transaction costs low, transaction costs may be relatively low as argued by Hakvoort et al. (2009). The argument that a monthly averaging period would result in smaller transaction costs is not convincing because the generators in the constrained off area would have to estimate not only their marginal costs during times that they would be constrained off (and if their costs vary significantly over the day or week, this would be challenging enough), but also the price for constrained on power during those times, which will certainly vary over hours and days. This would be a very sophisticated and risky forecasting effort, and a considerable burden, especially for small generators.

In addition, there are some highly significant drawbacks associated with a monthly auction for congestion rights. This structure requires generators to estimate an average expected price for constrained on power. Hourly prices will differ indefinitely from the average, while estimates may differ significantly from generator to generator and from realisation. Therewith, the bid curve for the monthly auction is not likely to represent the most efficient priority order for constraining generators off. Inefficient redispatch is likely to result and redispatch costs may result to be significantly higher than efficient redispatch costs.

5.4 Hybrid Redispatch Model

5.4.1 Brief Description

The hybrid redispatch model assumes a reduction of volume in congestion areas according to bids of generators in a congestion rights market, like the market redispatch model. Constrained off generators are however required to purchase compensatory power from the TSO at APX prices, while non-constrained off generators are required to pay a congestion fee set by the highest accepted bid for the congestion rights market. The TSO purchases compensatory power in non congestion areas.

The constrained off market involves a single-side bidding procedure, where generators in congestion areas signal their respective expected cost of redispatch. For competitive bidding it is assumed that generators will bid in the expected cost of redispatch, i.e. the (expected) APX price minus the marginal cost of operation.[13] A bid and its relative position in the resulting bid curve only determines the priority of constraining a particular unit off in the face of redispatch requirements where priority is given in the order of increasing bids, i.e. priority of redispatch is given to the units with the lowest expected redispatch costs. No payment is associated with the bid.

Once congestion occurs, the TSO assigns the necessary constrained off volume to the bids in order of increasing redispatch costs. Generators, whose bids are ‘accepted’, are selected to be constrained off. In addition, the highest bid accepted sets the marginal congestion price, or the congestion fee, which is charged to generators that are not constrained off.

The generators that are constrained off are obliged to contract compensatory power from the TSO at APX prices, without any financial compensation. The TSO is expected to contract compensatory power in the non-congested areas. The constrained on market is proposed to involve a centralized market with uniform pricing.

5.4.2 Assumptions

The congestion model description by Hakvoort et al. (2009) assumes a binary network system with only one congestion region and one non congestion region. The nodal decomposition of the Dutch network applied for the representation of the Dutch power system involves four nodes, among which multiple nodes may show congestion or offer constrained on power.

For the purpose of the welfare calculations it is assumed that for each congestion region a nodal congestion fee applies. The nodal congestion fee is based on the node-specific highest constrained off bid accepted.

[13] If the submission of bids is scheduled after clearance of the APX, the settlement prices are known. However, if it is required that bidding takes place prior to clearing, these prices will need to be estimated.

In order to simulate the welfare results for the market redispatch model an additional assumption is required regarding the bids of the generators in the congestion area. As indicated in the previous section, bids of generators in congestion areas are expected to reflect their respective costs of redispatch, set by the (expected) APX price of compensatory power offered by the TSO minus their individual marginal cost of operation.

For the purpose of the following welfare analysis, bids of constrained off generators are simulated by the single node price minus the respective marginal cost of operation of the generators in the constrained off region. Hence it is assumed that all generators in the congestion areas are able to predict the APX price accurately, or that the APX price is known at time of the bidding.

5.4.3 Simulation Results

The simulation results for the hybrid redispatch model in case of Scenario A (High New Generation Capacity) as applied to the simulation of the Dutch power system are presented in Table 5.3 . As before, the resulting yearly generator surplus in each of the regions distinguished is presented. The generator surpluses are differentiated for the constrained off (C_{off}), non constrained off (non C_{off}) and constrained on (C_{on}) generators. The national surplus, TSO surplus, total redispatch costs and the change in surplus as a percentage of the total redispatch costs are presented as well. Results are presented for both the case of sufficient transmission capacity (dispatch) and the case of insufficient transmission capacity (redispatch).

Compared to the system redispatch model, the loss of surplus for the generators in the congested areas again increases significantly, be it somewhat more moderate than the case for the market redispatch model. For instance, the non-constrained off generators in Zuid-Holland lose a significant proportion of their surplus due to the congestion fee, reducing their surplus -24% per year which is a somewhat more moderate reduction than in case of the market redispatch model but higher than the reduction in case of the system redispatch model with cost pass-through to generators. For Scenario A the congestion fee itself amounts to some 0.90€/MWh on average per year, but may go up to levels of some 5€/MWh during super peak in mid season. Furthermore, the constrained off generators' surplus is zero in the hybrid redispatch model because the congestion fee, set by the difference between APX prices and the marginal cost of operation, is equal to the marginal revenue of the partially constrained off unit.

Table 5.3 Yearly surplus simulations for hybrid redispatch model for Scenario A

	Dispatch [mln €/yr]	Redispatch [mln €/yr]	Delta [mln €/yr]	[% of RDC]
Surplus Gen NN	431.68	436.19	4.51	10
NN C_{off}	0.00	0.00	0.00	0
NN non C_{off}	0.00	0.00	0.00	0
NN C_{on}	0.00	4.51	4.51	10
Surplus Gen RN	451.65	474.99	23.34	50
RN C_{off}	0.00	0.00	0.00	0
RN non C_{off}	0.00	0.00	0.00	0
RN C_{on}	0.00	23.34	23.34	50
Surplus Gen ZH	305.24	233.54	-71.70	-153
ZH C_{off}	21.59	0.00	-21.52	-46
ZH non C_{off}	207.79	157.69	-50.18	-107
ZH C_{on}	0.00	0.00	0.00	0
Surplus Gen ZL	165.89	168.13	2.24	5
ZL C_{off}	0.00	0.00	0.00	0
ZL non C_{off}	0.00	0.00	0.00	0
ZL C_{on}	0.00	2.24	2.24	5
Surplus TSO	0.00	-5.35	-5.35	-11
Surplus Gen NL	1354.46	1312.85	-41.61	-89
Total Surplus	1354.46	1307.50	-46.96	-100
Redispatch Costs			46.96	

In contrast to the case of system redispatch, that assumes a pay-as-bid pricing, the hybrid redispatch model results in increases of surplus for the constrained on generators in the Northern Provinces (NN), Zeeland (ZL) and the ring (RN) which is also observed in the market redispatch model.

Compared to the market redispatch model, the distributive effects of this system are likely to be moderate. Both the total incurred costs for the non-constrained off generators and the revenues for the TSO are substantially lower in the hybrid redispatch model. As the bid for constrained off in this model is set by the APX price minus marginal cost, instead of expected constrained on price minus marginal cost, the constrained off bids are much lower; therefore, congestion fees are substantially lower than in case of the market redispatch model.

Tables D.1, D.2 and Tables D.3, D.4 in Appendix D, the simulation results for Scenario B (Low Generation investment) and Scenario C (High Wind) are presented. In both cases, overall redispatch costs decline significantly as less congestion occurs. The distributive effects of the scheme are in line with the results for Scenario A.

5.4.4 Discussion

For the competitive evaluation, the hybrid redispatch shows the moderate distributive effects and losses in congested areas in comparison to the three other systems considered. Therewith, the risk of spill-over of redispatch costs into the wholesale market, indirectly affecting consumers, is not a predominant characteristic for this system. This system is offers no benefits for being constrained off so incentives are in line with the requirements, both for the short as for the long term.

The generator bids are proposed to be based on APX prices. If the submission of bids is scheduled after clearance of the APX, the APX prices are known, so that no estimation is required and the bid curve is likely to represent the most efficient priority order for constraining generators off. However, if it is required that bidding takes place prior to APX clearing; the APX prices need to be estimated.

The main risk associated with this system is that it leaves the TSO exposed to differences in the revenues resulting from the congestion fee and costs of redispatch, being the difference between constrained on costs and the APX price. Such risk would be mitigated if the congestion fee would be set as is the case for the system redispatch with cost pass-through to generators. This would imply that the congestion fee would be set by total congestion costs.

5.5 Market Agent Approach

5.5.1 Brief Description

The market agent approach transfers the responsibility to deal with congestion entirely to market parties. The implementation considered involves a *pro rata* reduction of the transmission rights of all generators in congestion areas until the congestion is solved. The generators need to compensate for the reduced generation by themselves, by purchasing power in the non-congestion areas. No financial compensation is offered to the constrained-off generators. Therefore all redispatch costs rest with the generators in the congestion region.

The pro rata assignment of transmission rights compromises efficient redispatch of the power system as it assigns capacity to be constrained off irrespective of the associated marginal cost of production, rather than that highest-cost facilities are constrained off. A secondary market for congestion rights may therefore arise. Trading transmission rights such that low-cost generators can maintain their nominated production, while high-cost generators become increasingly constrained off therefore decreases total redispatch costs and increases overall surplus for the generators. Clearly generators therefore have a parallel interest to re-allocate the transmission rights such that efficient allocation of generation is achieved, but distribution of the benefits and transaction costs may compromise efficient re-allocation.

5.5.2 Assumptions

In case of the rise of a secondary market for transmission rights[14], it is required that price formation of transmission rights is characterized and quantified. To this end one may characterize the value of transmission rights to the various generators in a congestion region, as in Figure 5.1. Here a stylised nodal residual supply curve is presented for some congestion region, with price P or marginal costs MC in €/MWh versus Volume Q in MW. The nominated or unconstrained production volume is indicated as Q_u which has been sold at an unconstrained price P_u. However the available transmission capacity T is lower than nominated production Q_u and congestion management is required. The efficiently dispatched non constrained off volume (NCV) is shown to be equivalent to the transmission capacity, while the remainder of the nominated production is indi-

[14] The rise of an explicit market for transmission rights is somewhat hypothetical as it would require tradable transmission rights with an associated institutional framework. For the purpose of this analysis however a hypothetical market for transmission rights forms a convenient framework of analysis. In practice transmission rights may be traded implicitly through trading of production volume among the constrained off generators in a particular node, for example through bilateral trading. Such trading seems less likely to take place through the intra-day market as this market currently does not accommodate for distinction of locational aspects of production.

cated as efficiently dispatched constrained off volume CV. Pro-rata reduction of transmission rights is indicated for two generators G1 and G2, by the representation of the constrained off volume CV1 of generator G1 and the non constrained off volume NCV_2 for generator 2. The sum of all CV_n of all generators in the efficient NCV range equals the sum of the NCV_n in the efficient CV range.

The value of transmission rights that would accommodate production of CV_1 is determined by the sum of the lost profit due to being constrained off, indicated in red, and the avoided cost of redispatch, indicated in dashed red. Here the loss of profit equals to the generator surplus for this volume, i.e. the total revenues for CV_1 minus the total cost of production of CV_1.

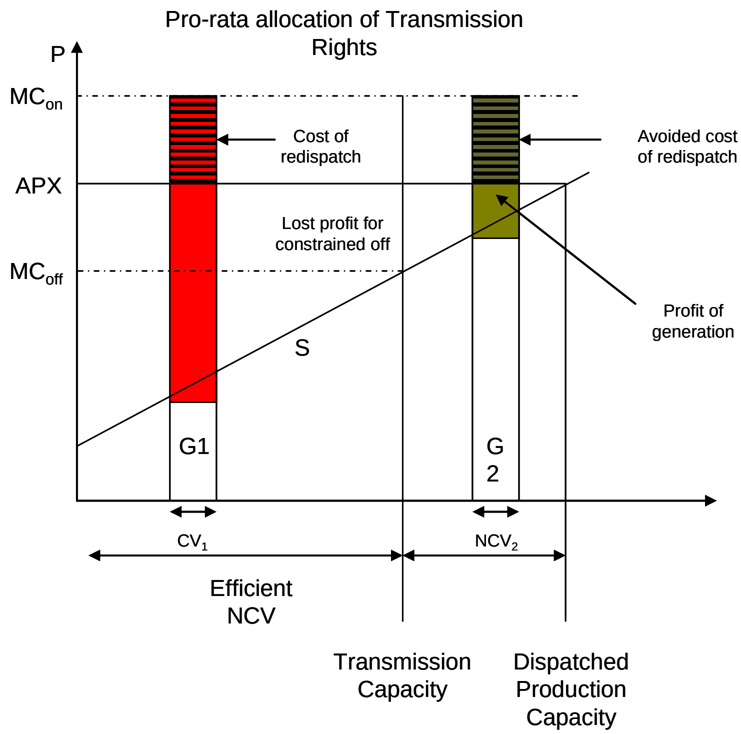

Figure 5.1 *Pro-rata grand-fathering of transmission rights*

The avoided cost of redispatch equals to the total cost of compensating constrained on volume priced at marginal cost MC_{on}, minus the total revenues for CV_1, priced at P_u. Accordingly the value of transmission rights for generator G2 is represented by the sum of profit of generation and the avoided cost of redispatch for volume NCV_2.

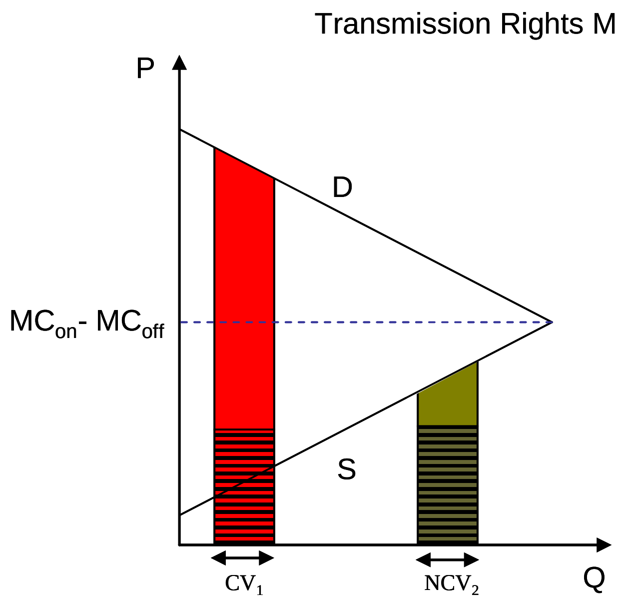

Figure 5.2 *Nodal transmission rights market assuming competitive pricing in a liquid market*

The supply of transmission rights is formed by all NCV_n volumes in the efficient CV range. The associated supply curve is determined by a curve of strictly increasing value of transmission for the generators in the efficient CV range, as indicated in Figure 5.2. Analogously, demand for transmission rights arises from all CV_n volumes in the efficient NCV range, and the demand curve is formed by the strictly decreasing value of transmission for the generators in the efficient NCV range.

The sums of all CV_n in the efficient NCV range and NCV_n volumes in the efficient CV range and the equilibrium price would be equal to the marginal costs of constrained on power MC_{on} minus the efficient marginal cost of constrained off volume MC_{off}. This equilibrium outcome for the transmission rights market is however hampered by the fact that it requires a liquid and competitive market with many generators, so that a relatively smooth supply and demand curve for transmission rights reflecting the respective opportunity costs of transmission will result. In case of Figure 5.2 where only two generators G1 and G2 consider trading of transmission rights, one may observe that generator G1 and G2 value the transmission rights at widely different levels. Effectively one could consider the transmission rights price to be indeterminate in such a market context.

For the purpose of the evaluation of welfare impacts of the market agent approach with secondary market, we assume transmission rights market in each congestion area to be liquid, and competitive with many generators, which of course is a strong assumption. Transmission rights are therefore assumed to be traded at price levels equal to the delta of the MC_{on} and the nodal MC_{off}.

5.5.3 Simulation Results

The simulation results for the market agent model in case of Scenario A (Moderate generation investment) as applied to the simulation of the Dutch power system are presented in Table 5.4. As before, the resulting yearly generator surplus in each of the regions distinguished is presented. The generator surpluses are differentiated for the constrained off (C_{off}), non constrained off (non

C_{off}) and constrained on (C_{on}) generators. The national surplus, TSO surplus, total redispatch costs the total redispatch costs are presented as well. Results are presented for both the case of sufficient transmission capacity (dispatch) and the case of insufficient transmission capacity (redispatch). Finally the change in surplus is presented both in absolute terms and as a percentage of the redispatch costs (RDC).

Based on this scenario, the only constrained off generators in Zuid-Holland face a high loss of surplus as they are required to compensate loss of volume by contracting constrained on power. The non-constrained off generators also lose some proportion of their surplus due to buying transmission rights from high cost constrained off generators in the secondary market.

As in the market and hybrid redispatch models, the market agent model also results in the same impact on surplus increase for the constrained on generators in the Northern Provinces (NN), Zeeland (ZL) and the ring (RN).

Similar to the hybrid redispatch model, the distributive effects of this scheme is likely to be moderate. Finally as expected, the TSO remains unaffected by this scheme, since the TSO assigns transmission rights and leaves the market to deal with redispatch costs.

Table D.1, D.2 and Table D.3, D.4 of Appendix D, the simulation results for Scenario B (Low Generation investment) and Scenario C (High Wind) are presented. The distributive effects of the scheme are in line with the results for Scenario A.

Table 5.4 *Yearly surplus simulations for the market agent approach for Scenario A*

	Dispatch	Redispatch	Delta	
	[mln €/yr]	[mln €/yr]	[mln €/yr]	[% of RDC]
Surplus Gen NN	431.68	436.19	4.51	10
NN C_{off}	0.00	0.00	0.00	0
NN non C_{off}	0.00	0.00	0.00	0
NN C_{on}	0.00	4.51	4.51	10
Surplus Gen RN	451.65	474.99	23.34	50
RN C_{off}	0.00	0.00	0.00	0
RN non C_{off}	0.00	0.00	0.00	0
RN C_{on}	0.00	23.34	23.34	50
Surplus Gen ZH	305.24	228.19	-77.05	-164
ZH C_{off}	21.59	-3.19	-24.70	-53
ZH non C_{off}	207.79	155.52	-52.35	-111
ZH C_{on}	0.00	0.00	0.00	0
Surplus Gen ZL	165.89	168.13	2.24	5
ZL C_{off}	0.00	0.00	0.00	0
ZL non C_{off}	0.00	0.00	0.00	0
ZL C_{on}	0.00	2.24	2.24	5
Surplus TSO	0.00	0.00	0.00	0
Surplus Gen NL	1354.46	1307.50	-46.96	-100
Total Surplus	1354.46	1307.50	-46.96	-100
Redispatch Costs			46.96	

5.5.4 Discussion

In this system TSO and consumers are not directly exposed. This system shows moderate distributive characteristics like the hybrid redispatch model. Accordingly, the risk of spill-overs of redispatch costs into the wholesale market, indirectly affecting consumers, is not a predominant characteristic for this system.

On should note however that a liquid secondary market for transmission rights is assumed. At this stage it is unclear if such a market could come to existence as only the generators in a congestion region can trade these rights. If no efficient arbitrage takes place, pro rata redispatch applies which by definition is inefficient and may result in a significant increase in redispatch costs.

5.6 Conclusions

Reviewing the simulation results and the discussions on each of the congestion management systems within the context of non-strategic behaviour, one may conclude that each of the systems has its virtues, but also disadvantages.

An overview of the findings regarding the simulations is presented in Table 5.5. In this table, the change of yearly generator surplus in each of the regions distinguished, is presented as a percentage of total redispatch costs (RDC). The generator surpluses are differentiated for the constrained off (C_{off}), non constrained off (non C_{off}) and constrained on (C_{on}) generators. The national surplus, TSO surplus, total redispatch costs the total redispatch costs are presented as well. Results for all four congestion management systems are presented. Here one may be observed that within the context of this assessment, total surplus change for all four systems is equivalent and equals the total redispatch costs. However, the distributive effects of the systems differ substantially. Particularly the market redispatch model shows a remarkable transfer of surplus from both constrained off and non-constrained off generators to the TSO, which totals an amount that is some seven to eighth times higher than the total redispatch costs. Both the hybrid model and the market agent approach show more moderate levels of redistribution of income, while the system redispatch model with cost pass-trough to generators results in transfers that match the total redispatch costs exactly.

An overview of the additional findings in this chapter is presented in. Table 5.6. Here the signs indicate if the congestion management system considered performs well (+), moderate (+/-) or poor (-) regarding the critical aspect considered.

Table 5.5 *Change of surplus as % of total redispatch costs for Scenario A (Baseline Scenario)*

	System Redispatch Model with cost pass-through to generators [%]	Market Redispatch Model [%]	Hybrid Redispatch Model [%]	Market Agent, with efficient secondary market [%]
Surplus Gen NN	0	10	10	10
NN C_{off}	0	0	0	0
NN non C_{off}	0	0	0	0
NN C_{on}	0	10	10	10
Surplus Gen RN	0	50	50	50
RN C_{off}	0	0	0	0
RN non C_{off}	0	0	0	0
RN C_{on}	0	50	50	50
Surplus Gen ZH	-100	-759	-153	-164
ZH C_{off}	-9	-235	-46	-53
ZH non C_{off}	-91	-524	-107	-111
ZH C_{on}	0	0	0	0
Surplus Gen ZL	0	5	5	5
ZL C_{off}	0	0	0	0
ZL non C_{off}	0	0	0	0
ZL C_{on}	0	5	5	5
Surplus TSO	0	594	-11	0
Surplus Gen NL	-100	-694	-89	-100
Total Surplus	-100	-100	-100	-100

System redispatch with cost pass-through offers a system that resembles current practice and has been known to be applied in multiple instances in the past. Furthermore, it inherently leaves both consumers and TSO unexposed directly to the price developments in the associated markets. Distributive effects are relatively limited so that market impacts are relatively low, limiting the risk of spill-over of redispatch costs into the wholesale market. In addition, it assumes centralized markets for both constrained off and constrained on power so that the congestion management system offers relatively open access for both small and large players and required transactions will come at relatively low costs. For the long run, the system may motivate generators to keep inefficient facilities up and running that would otherwise be candidates for decommissioning.

Market redispatch results in relatively strong distributive effects due to the congestion fee that is set by the price difference between expected constrained on price and marginal cost of operation of the respective generators in the congestion regions. This induces the risk of spill-over of redispatch costs into the wholesale market, as structurally loss-making sales may drive generators to withdraw capacity from the market. As such the system shows an increased risk of indirectly exposing consumers to the costs of redispatch. No direct exposure to costs of redispatch results for either consumers or the TSO however. The system assumes bilateral trading for both constrained off and on power, so that access for small generators may be compromised. In addition transaction costs may be high as a result of bilateral trading. The proposal to introduce a monthly congestion rights auction induces a significant increase of uncertainty in the expected redispatch cost assessment as it requires for month-ahead forecasting of the constrained on price. The resulting spread in expectations seems likely to compromise the actual least-cost priority order of the generator bids and, as a consequence, may result in inefficient dispatch and increased overall redispatch cost. Long term efficiency of the system, such that generators are incentivised to decommission obsolete capacity and not motivated to invest in new generation capacity in congestion areas seem assured, as generation capacity in a congested region under the market redispatch system faces significant costs due to the congestion fees.

The hybrid redispatch model leaves the TSO directly exposed to the delta between APX prices and the prices of the constrained on power, which is a significant drawback. The distributive effects of this system are more moderate than for the market redispatch system, so that indirect exposure of consumers through spill-over of redispatch costs into the wholesale market is modest. As this system assumes a centralized market for the constrained off power, accessibility of the constrained off market for small generators seems assured. As far as competitive behaviour is assumed, efficiency of redispatch for the system does not seem to be compromised as redispatch costs relate to the APX price which is assumed to be known at time of constrained off bidding. In addition, no benefits can arise from being constrained off as costs of compensatory power will be equal to the revenues of original sales on average. As far as long term efficiency is concerned, both for constrained off and non constrained off capacity, profitability decreases in comparison to unconstrained dispatch, hence no more incentives arise from the congestion management system to maintain inefficient capacity or consider investment in new generation capacity in the congestion region.

Table 5.6 *Assessment of critical (dis)advantages of the congestion management systems considered*

	System Redispatch Model with cost pass-through to generators	Market Redispatch Model	Hybrid Redispatch Model	Market Agent approach, with efficient secondary market
Distributive effects	+	-	+/-	+/-
Direct exposure of consumers and TSO	+	+	-	+
Indirect exposure of consumers due to spill-over	+	-	+/-	+/-
Accessibility of constrained off/on market for small generators	+	-	+	-
Transaction costs for generators	+/-	-	+/-	-
Efficiency of redispatch	+	-	+	+
Long term efficiency	-	+	+	+

The market agent approach leaves TSO and consumers with no direct exposure to the costs of congestion. Assuming an efficient secondary market however, distributive effects are comparable to the hybrid redispatch model; hence this system shows comparable moderate risk of indirect exposure of consumers to costs of congestion due to potential spill-over into the wholesale market. Accessibility of the constrained on and off market for small scale generators may be compromised as the system assumes bilateral trading. In addition transaction costs for generators may result to be relatively high, like in the case of the market redispatch model. Assuming an efficient secondary market, the system results in efficient redispatch. However, if no efficient secondary market arises, inefficiencies in redispatch may result, at least partially, in redispatch on a pro rata basis. As a consequence overall system cost of redispatch may result to be significantly higher than the least-cost solution. Long term efficiency of this system seems assured, in line with the expectations regarding the market redispatch.

Conclusively it is fair to state that both the market redispatch model shows some significant disadvantages within the context of the preceding assessment. The market redispatch model may result in strong distributive effects, increasing costs for generators such that they may be forced to refrain from offering power in the wholesale market resulting in spill-over of redispatch costs into the wholesale market. A moderate performance with regard to the criteria considered is offered by the market agent approach. However this performance is somewhat conditional as the assessment assumes an efficient and liquid secondary market for transmission rights to arise. Such a market should come to existence and may require additional regulation. If such a market does not come to existence, inefficient redispatch may result inducing significant increases of overall redispatch costs. The system redispatch model with cost pass-through to generators and the hybrid redispatch model offer a more beneficial perspective in several respects. The system redispatch with cost pass-trough however may be hampered by limited performance regarding the long term efficiency of the system, whereas the hybrid redispatch model leaves the TSO partially exposed to the redispatch costs. This exposure could be mitigated if the congestion fee would be set, following the methodology proposed for system redispatch with cost pass-trough to generators.

6. Analysis under Strategic Behaviour

6.1 Introduction

Strategic behaviour is a crucial aspect to consider in market design. Generally speaking, international experience in power markets suggests that if there are opportunities for strategic behaviour, there will be strategic behaviour. However strategic behaviour is generally difficult to detect and prove. On the other hand, once proof of strategic behaviour has been established, ex-post mitigating measures have shown to be cumbersome and often ineffective. Therefore structural market design solutions and incentive mechanisms seem to be a preferable approach for mitigation of opportunities and impacts of strategic behaviour, though it is not always feasible.

In this chapter the opportunities for and consequences of strategic behaviour under various congestion management schemes will be analysed. Strategic behaviour in this context will involve adjusted bidding behaviour regarding both price and/or volume, such that systematically higher profits result for the bidder than would be the case if this agent behaves as is assumed in the analysis presented in Chapter 5 on competitive behaviour.

Strategic behaviour is an inherently complex theme to analyse as the opportunities for strategic behaviour may be highly dependent on the particularities of the portfolio of a specific generator. If for example a particular generator owns both generation capacity in a constrained off area and a constrained on area, opportunities for strategic behaviour may substantially differ from a generator that owns generation capacity in the constrained off area only. Moreover, these opportunities will also depend on the associated marginal cost of operation, relative to the marginal cost of competing capacity in the area, i.e. the position of the generator on the local merit order. In addition to individual generator portfolios, one may account for combined generator portfolios as generators may find joint interests and may show strategic behaviour as if they operate as a single entity. Such joint behaviour may arise as a result of agreements between generators but can even arise without explicit communication and/or signalling but through mutual independent recognition of such opportunities and establishment of an informal behavioural agreement, also called *tacit* collusion. Opportunities to explore such mutual understanding are particularly well provided within the context of daily markets, effectively offering repeated games where initial exploration may come at some costs but eventually significant pay-off may result.

For a full ex-ante analysis of the opportunities for strategic behaviour, be it for single generators or for colluding generators, it would therefore be required to consider all conceivable configurations of generation capacity, underlying fuel price developments and the associated opportunities for strategic behaviour. Clearly this is an impossible task. As a pragmatic approach, a variety of strategies will be explored on the basis of systematic analysis of generic opportunities for each of the classes of generators participating in the congestion management systems considered, i.e. the constrained off, non-constrained off, and constrained on generators. If appropriate, increasing complexity of the ownership structure will be considered on the basis of international experience regarding strategic behaviour in the face of congestion management.

6.2 Classification of Strategies

As far as strategic behaviour within the context of congestion management systems is concerned, a variety of strategies may be considered. In this chapter only strategies will be considered that may be applied generically by a particular class of generators affected by the introduction of a congestion management system in the face congestion (constrained off, non-constrained of and constrained on).

A distinction of strategies that apply to the constrained off market and the constrained on market can be made. Furthermore within each of these markets, one may distinguish between strategies that involve strategic adjustment of the height or level of the price bidding on one hand and strategic adjustment of the volume offered on the other, both in comparison to competitive bids. Of course these strategies may be applied individually or combined.

In the following sections therefore the following four types of strategic behaviour are considered:
- Strategic price bidding in the constrained off market.
- Strategic volume bidding in the constrained off market.
- Strategic price bidding in the constrained on market.
- Strategic volume bidding in the constrained on market.

The potential and the consequences of the instances for each of these strategic options, will be discussed for each congestion management system evaluated.

Strategies for the TSO to increase surplus are not considered in this analysis. Though the Dutch TSO currently is a non profit organisation it is however considered to be conceivable that the TSO would behave strategically. Moreover it seems conceivable that the future role of the TSO in the Dutch power system changes and the organisation would become a profit-driven organisation. It is however assumed that due to the nature of the central role of the TSO in the power system, close monitoring and accounting of the behaviour of the TSO by the regulator should be in place. In addition, as the TSO has a natural monopoly, transparency and accountability regarding its decision-making procedures do not form a risk for its position in the market. Therefore legal obligations to offer transparency and accountability can and should be enforced and will harness non strategic behaviour of this entity.

6.3 Strategic price bidding in the constrained off market

If there are costs associated with the level of the constrained off bids, it will pay off to reduce the level of the bids in the constrained off market. In case of system redispatch with cost pass-through to generators, the level of the bids in the constrained off market represent the generators' willingness to pay for the transferral of their production obligations. Decreasing the bid level effectively decreases the costs for the constrained off generators and as such increases the compensation from being constrained off. This opportunity for gaming is discussed in Section 6.3.1. In case of both the market redispatch and the hybrid redispatch model, no payment is associated with the constrained off bids but the highest bid accepted sets the congestion fee. If the market agents successfully reduce the level of their respective bids in the constrained off market, this would result in a reduction of the congestion fee. This opportunity for gaming is discussed in Section 6.3.2.

6.3.1 Increasing constrained off compensation

The strategy to increase constrained off compensation involves reducing the bid levels reflecting the willingness to pay to transfer production obligations to the TSO. As for this market a pay-as-bid pricing structure is assumed, generators will enjoy higher profits if they bid below marginal cost of production. However that comes at risk of being constrained on. Being constrained on at reduced bid levels is not beneficial as it implies that the generator will remain to face production requirements with the additional costs of congestion fees. Given the assessment of congestion fees for the system redispatch model with cost pass-through for Scenario A, the exposure seems limited in the sense that congestion fees are likely to be in the order of several Euros per MWh. It would be more beneficial to be constrained off however, as in that case no congestion fees are to be paid and profits are equal to or higher than the profits enjoyed in case of actual production. Therefore generators expecting to be candidates for being constrained off on the basis of competitive bidding and efficient redispatch may consider reducing their bids to the levels of the expected marginal bid, i.e. the expected highest bid accepted. This applies in particular to generators in the high end of the supply curve. Consequently one may expect all the generators expecting to be constrained off to bid at or around the expected highest bid accepted. As such the pay-as-bid pricing structure effectively transforms into a uniform pricing structure with uniform prices equalling the expected highest bid accepted. One may therefore conclude that the pay-as-bid pricing structure will induce generators to bid the expected uniform price levels.[15] One should also note that due to the uncertainty involved here, the expectations may differ and inefficient dispatch seems likely to result though to a lesser extend than in case of bidding in the monthly congestion rights auction proposed for the market redispatch model (see Section 5.3.4).

Consequently, overall redispatch costs may increase compared to the competitive analysis. As these costs are being passed-through by the TSO in the form of an increased congestion fee, the additional costs end up with the non constrained off generators. This form of strategic behaviour therefore results in an additional transfer of surplus from non-constrained off generators to constrained off generators.

[15] This is a particular case from the more general “revenue-equivalence theorem,” which states that, having enough information, bidders would incorporate into their bids any change in the market rules, trying to obtain the most favorable possible result from the market. Market outcome will therefore remain constant at the market equilibrium point independently of which format is used for the auction (although the theoretical proof does not fully hold for the case of an electricity market).

Table 6.1 *Yearly surplus simulations for system redispatch with cost pass-through to generators, assuming 'reduced constrained off bidding'*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain [mln €/yr]
Surplus Gen NN	431.68	431.68	431.68	431.68	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen RN	451.65	451.65	451.65	451.65	0.00
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZH	305.24	258.28	305.24	258.28	0.00
ZH C_{off}	21.59	17.28	21.59	17.06	0.22
ZH non C_{off}	207.79	165.15	207.79	165.36	-0.22
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	165.89	165.89	165.89	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus TSO	0.00	0.00	0.00	0.00	0.00
Surplus Gen NL	1354.46	1307.50	1354.46	1307.50	0.00
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

It should be emphasised that even if a particular generator owns both constrained off and non-constrained off generation in the congestion area such a strategy would pay off as the costs of the additional benefits for the constrained off generation are socialized among the non-constrained off generators. Only when a generator owns all non-constrained off capacity, no benefits would result from this strategy as then the added benefits for the constrained off capacity would go at an equivalent increase of total costs for the congestion fees.

In case only few generators have presence in the congestion region, market power or (tacit) collusion may aggravate the opportunity for strategic behaviour in the sense that the generators may uniformly reduce bid levels. However the additional benefits resulting for the constrained off volume will go at cost of the increase of total costs due to the increasing congestion fees. Generators expecting to be non constrained off on the basis of competitive behaviour and efficient redispatch have little to gain with decreasing bids, as it will only reduce the chances of being constrained off which is more beneficial than not being constrained off. In addition, reduction of bids from non constrained off generators only increases the opportunity for constrained off generators to reduce their bids without being constrained off and as such only increases redispatch costs and therewith congestion fees.

The potential additional transfer of surplus from non-constrained on generators to constrained off generators for the case of Scenario A is indicated in Table 6.1. In this table, the surplus results for reduced bidding at level of the highest bid accepted are reported adjoined with the original results for the assumptions laid down in the analysis for competitive behaviour. In addition, the column on the right-hand side of the table reports the gain in surplus for each of the agents considered. This strategy results in a relatively limited gain of surplus of some 0.85 mln € yearly for the constrained off generators in Zuid-Holland, at cost of the non-constrained off surplus in this region.

The extent to which this strategy pays off for constrained off generators seems somewhat limited in comparison to overall surplus. It is important to realise that this is a direct consequence of the assumed Scenario for generation investment in the congestion region Zuid-Holland, being Scenario A. If more capacity would be available in the congestion region, the extent to which this strategy pays of could be higher.

6.3.2 Gaming the congestion fee

In case the congestion fee is set by the highest constrained off bid accepted, it will pay off the decreased bids for constraining off power. This is the case for both the market redispatch and the hybrid redispatch model.

The reduced bidding of the individual generator(s) expecting to be offering the congestion fee-setting bid therefore entails the unfavourable risk of being fully constrained off. However in case the individual generator(s) expecting to be offering the congestion fee-stetting bid own a substantial amount of capacity that is expected not to be constrained off, reduced bidding will induce costs reductions for the non constrained off capacity at risk of having some more capacity being constrained off. Reduced bidding may therefore result to be a beneficial strategy, particularly in case of unilateral market power, i.e. if only few generators have presence in the congestion area.

Table 6.2 *Yearly surplus simulations for market redispatch, assuming 'reduced constrained off bidding'*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain [mln €/yr]
Surplus Gen NN	431.68	436.19	431.68	436.19	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	4.51	0.00	4.51	0.00
Surplus Gen RN	451.65	474.99	451.65	474.99	0.00
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	23.34	0.00	23.34	0.00
Surplus Gen ZH	305.24	228.19	305.24	-50.97	279.16
ZH C_{off}	21.59	-55.53	21.59	-88.73	33.20
ZH non C_{off}	207.79	207.87	207.79	-38.10	245.97
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	168.13	165.89	168.13	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	2.24	0.00	2.24	0.00
Surplus TSO	0.00	0.00	0.00	279.16	-279.16
Surplus Gen NL	1354.46	1307.50	1354.46	1028.34	279.16
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

Clearly decreased bidding for the generator expecting to be offering highest bid accepted implies an increased risk of being constrained off for this generator. In the particular case of the market - and hybrid redispatch models, it is unfavourable to be constrained off as in these systems there is no compensation offered for being constrained off. In case of the market redispatch model a generator being constrained off is facing the costs of compensatory power in the constrained on market, which is expected to be higher than the revenues from the original sales on average. In case of the hybrid redispatch model, a generator being constrained off is facing the costs of compensatory power at APX price, which is expected to equal the revenues from the original sales on average.[16]

In Table 6.2 and Table 6.3, surplus results are reported for the case of market redispatch and hybrid redispatch respectively. These tables indicate an extreme case in which the generators game the congestion fee to the max, i.e. assuming that bidding is such that the congestion fee results to be zero. It should be emphasized that this assumption seems somewhat extreme as the bid behaviour involves submission of bids at zero €/MWh in the congestion rights market. Such low levels should trigger the regulator to investigate the constrained off market. The results therefore are likely to exaggerate the gains somewhat and should be considered as the maximum gains achievable. Bid level reductions of some 10% to 20% may however go undetected and more difficult to prove.

Table 6.3 *Yearly surplus simulations for hybrid redispatch, assuming 'reduced constrained off bidding'*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain [mln €/yr]
Surplus Gen NN	431.68	436.19	431.68	436.19	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	4.51	0.00	4.51	0.00
Surplus Gen RN	451.65	474.99	451.65	474.99	0.00
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	23.34	0.00	23.34	0.00
Surplus Gen ZH	305.24	290.29	305.24	233.54	56.75
ZH C_{off}	21.59	6.56	21.59	0.00	6.56
ZH non C_{off}	207.79	207.87	207.79	157.69	50.18
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	168.13	165.89	168.13	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	2.24	0.00	2.24	0.00
Surplus TSO	0.00	-62.10	0.00	-5.35	-56.75
Surplus Gen NL	1354.46	1369.60	1354.46	1312.85	56.75
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

[16] It is important to realise that revenues from sales result from forward trading, whereas costs of compensatory power are set by day-ahead trading. Though it may be assumed that there are no long term structural opportunities to arbitrage between forward and day ahead markets, it may be that during prolonged periods of time, like one or more quarters of a year, price levels of day ahead markets differ on average from forward markets. Is such effects are not structural, it is considered to be impossible to anticipate the opportunities such dynamics entail for generators and it is therefore assumed that no structural strategic approach can be developed seeking to exploit such temporary imbalances.

In the left-hand side of both tables, results for this type of strategic behaviour are reported, followed by the results for competitive assumptions. Finally on the right-hand side, gains of each agent due to the strategic behaviour are reported.

In case of market redispatch, effective gaming of the congestion fee results in a complete transfer of TSO surplus to the constrained on generators in the congestion region Zuid-Holland. Also some surplus increase for the constrained off generators seems to result, but this relates to the capacity of constrained off generators that is not constrained off. The TSO ends up with zero surplus due to the redispatch with strategic behaviour as the TSO remains to be exposed to the cost of redispatch but no longer enjoys the revenues from the congestion fees.

In case of the hybrid system, also a complete transfer of TSO surplus relating to congestion fee revenues results towards constrained on generators in the congestion region Zuid-Holland. Again some surplus seems to be transferred to constrained off generators in the congestion region, but as mentioned before this relates to the non constrained off volume of the constrained off generators. In case of the hybrid system, the TSO ends up with significant negative surplus due to the redispatch with strategic behaviour as the TSO remains to be exposed to significant increase in the cost of redispatch.

Finally, one may note that if the congestion fee for the hybrid system would be set as in the case of system redispatch with cost pass-through to generators, as proposed in the previous chapter, this type of strategic behaviour would no longer apply.

6.4 Strategic volume bidding in the constrained off market: DEC games

Decreased bid games or DEC games[17] refer to games where an increased volume in congestion areas is nominated in comparison to efficient dispatch, aggravating or creating congestion. A variety of DEC games could be devised, depending on the market structure and institutional context. For the particular context of the future Dutch congestion management system two DEC games are distinguished in this analysis. The first DEC game (DEC1) involves a strategy that could be applied by any generator with *excess capacity* in a congestion region. Here excess capacity refers to capacity that would not be dispatched assuming efficient dispatch. The second DEC game (DEC2) considered, involves a DEC game that requires a generator to own excess capacity in a congestion area, but in addition owns an equivalent or higher amount of dispatched capacity in a non congestion area as well.

The DEC games only pay off in case there are benefits related to being constrained off. This is the case for system redispatch with cost pass-through to generators. In addition, if an efficient secondary market is assumed in case of the market agents approach, also the grand fathering of transmission rights in this system incentivises increased volume bids in the constrained off power. The following analysis therefore applies to the system redispatch model with cost pass-trough and the market agent approach assuming an efficient secondary market.

6.4.1 DEC1: a risky game

If a generator owns excess capacity in a congestion area, the generator may sell this capacity on the wholesale market at bid levels below its marginal cost, anticipating to be constrained off. This strategy only pays off in case constrained off generators are compensated, as is the case for the

[17] DEC games, or decrease bid games, were first observed in congestion markets in the USA.

system redispatch model with costs pass-through. Also for the market agent approach some benefits relate to overstating production in congestion regions, as this yields additional transmission rights. This is a risky game however as the generator may not be constrained off, for example in case no congestion occurs or due to the relative position of its bid in the bid curve. In these latter instances one would be forced to run at loss-generating price levels.

A comparable strategy that only applies to the market agent approach would involve a generator with excess capacity in a congestion region selling this capacity to a friendly party that does not need this power. The generator then subsequently bids in the constrained off market at levels below market price. In case the bid is accepted, the excess capacity is constrained off and any benefits associated with being constrained off are enjoyed. The friendly party now receives power sourced by constrained on producers, while it has no need for this volume. The friendly party may sell this excess production on the intra-day market. In case the bid is not accepted and the generator is not constrained off, the contract is annulled.

Like the first variant, this second variant leaves the colluding agents exposed to significant risk. In particular, the friendly party ends up with a volume it has no need for in case the generator bid for constrained off power is accepted. This volume will need to be sold in the intra-day market in order to avoid ending up in the imbalance market at high cost.

Table 6.4 *Yearly surplus simulations for system redispatch with cost pass-through to generators, assuming both reduced bidding and DEC1*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain [mln €/yr]
Surplus Gen NN	431.05	431.05	431.68	431.68	-0.63
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen RN	450.85	450.85	451.65	451.65	-0.80
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZH	285.40	254.81	305.24	258.28	-3.47
ZH C_{off}	5.07	17.74	21.59	17.06	0.67
ZH non C_{off}	204.48	161.22	207.79	165.36	-4.15
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.66	165.66	165.89	165.89	-0.23
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus TSO	0.00	0.00	0.00	0.00	0.00
Surplus Gen NL	1332.96	1302.37	1354.46	1307.50	-5.13
Total Surplus	1332.96	1302.37	1354.46	1307.50	-5.13
Redispatch Costs		-30.60		-46.96	

Table 6.4 presents results for the DEC1 game in case of system redispatch with cost pass-through to generators, in addition to assuming reduced bids for constrained off power as discussed in Section 6.3. The DEC strategy is applied by all generators with excess capacity in the congestion region Zuid-Holland. On the left-hand side, results for the assumed strategic behaviour are presented, followed by the results for competitive behaviour. On the right-hand side, surplus gain of each agent under the DEC1 game are reported.

One may take note of the fact that dispatch results differ for the strategic and competitive framework. As the strategy requires more volume to be offered at loss-generating price levels in order to result in actual increases of volume sold and nominated, the wholesale market equilibrium shifts somewhat. In comparison to the competitive dispatch, strategic dispatch results in the offering of higher volumes at low prices in the wholesale market, depressing equilibrium prices and inducing increased demand and export, while displacing higher cost generation capacity.

Accordingly overall surplus for the various agents and redispatch costs RDC change somewhat for the strategic case, resulting in overall lower redispatch costs. Would redispatch costs be based on the cost of competitive dispatch and the cost of strategic redispatch, the redispatch costs increase somewhat in comparison to competitive redispatch, to a level of - 52.09 mln € yearly.

As shown in Table 6.4 for system redispatch the strategy of DEC1 combined with decreased bids in the constrained off market results in a positive gain for the constrained of generators in the congestion region Zuid-Holland, where yearly gains amount some 0.67 mln €, at cost of the non constrained on generators.

Table 6.5 *Yearly surplus simulations for market agent approach, assuming an efficient secondary market and assuming DEC1*

	Strategic Dispatch	Strategic Redispatch	Competitive Dispatch	Competitive Redispatch	Gain
	[mln €/yr]	[mln €/yr]	[mln €/yr]	[mln €/yr]	[mln €/yr]
Surplus Gen NN	431.05	435.56	431.68	436.19	-0.63
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	4.51	0.00	4.51	0.00
Surplus Gen RN	450.85	477.78	451.65	474.99	2.79
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	26.93	0.00	23.34	3.59
Surplus Gen ZH	285.40	221.08	305.24	228.19	-7.11
ZH C_{off}	2.30	-3.82	21.59	-3.19	-0.63
ZH non C_{off}	207.25	149.04	207.79	155.52	-6.48
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.66	167.96	165.89	168.13	-0.17
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	2.29	0.00	2.24	0.05
Surplus TSO	0.00	0.00	0.00	0.00	0.00
Surplus Gen NL	1332.96	1302.37	1354.46	1307.50	-5.13
Total Surplus	1332.96	1302.37	1354.46	1307.50	-5.13
Redispatch Costs		-30.60		-46.96	

On the other hand, non constrained off generators in Zuid-Holland lose some surplus due to decrease in the wholesale prices. Generators in all non congestion regions also lose some surplus due to loss of sales in the wholesale market as the constrained off generators in Zuid-Holland offered more volume at loss-making price levels displacing sales from the other regions.

The congestion management model for the market agent approach implies benefits for increased volume offering in congestion areas as well, as it assumes free pro rata allocation of transmission rights. In case an efficient secondary market is assumed, these transmission rights represent a value as discussed in Section 5.3.2. Therefore, also in case of the market agent approach with an efficient secondary market it may pay off to increase bid volumes in the congestion area.

Table 6.5 presents results for the DEC1 game in case of the market agent approach. The DEC1 strategy is applied by all generators with excess capacity in the congestion region Zuid-Holland. On the left-hand side results for the assumed strategic behaviour are presented, followed by the results for competitive behaviour. On the right-hand side surplus gains of the strategy assumed are reported for each of the agents. Like for the case of system redispatch with cost pass-through to generators, the dispatch results differ for the strategic and competitive framework. As the strategy requires more volume to be offered at loss-generating price levels in order to result in actual increases of volume sold and nominated, the wholesale market equilibrium shifts somewhat. Accordingly overall surplus for the various agents and redispatch costs RDC change for the strategic case, resulting in overall lower redispatch costs. Would redispatch costs be based on the cost of competitive dispatch and the cost of strategic redispatch, the redispatch costs increases somewhat in comparison to competitive redispatch, to a level of - 52.09 mln € yearly.

As shown in Table 6.5, for market agent approach, the strategy of DEC1 results in a negative gain for the constrained off generators in the congestion region Zuid-Holland, where yearly gains amount some -0.63 mln €. On the one hand, the constrained off generators will experience an increase of the surplus resulting from the increased volume of transmission rights received, while on the other hand these generators face an increase of the production volume required to be compensated by purchases of constrained on power. If these latter costs are higher than the benefits resulting from the additional transmission rights, additional losses will arise. Whether additional losses or profits will result for the constrained off generators is highly dependent on the scenario assumed, so that outcomes are not robust. As such, this strategy seems particularly risky for the constrained off generators, though it is conceivable that actual market conditions render this strategy to be systematically profitable. Non-constrained off generators in Zuid-Holland lose some surplus due to both decrease in their revenues from lower wholesale prices and increase in their costs from buying additional transmission rights from constrained-off generators. Finally most generators in the Northern part of the Netherlands lose some surplus due to loss of sales as the constrained off generators in Zuid-Holland offered volume at loss-making price levels displacing sales in the other regions. The generators in the other non constrained off regions experience an increase of surplus for this scenario due to the increasing demand for constrained on power.

6.4.2 DEC2: a risk-free game

In case a generator owns excess capacity in a congestion area and an equivalent or higher amount of dispatched capacity in non congestion regions the generator is in the position to behave strategically and at virtually no cost or risk.

Assume a generator sells power conforming regular trading, i.e. not considering strategic behaviour regarding the congestion management scheme. Assume that these sales would result in some sales volume that under efficient dispatch would (at least partially) be sourced with capacity in a non congestion region and some excess capacity in the congestion region. The generator may now claim to source some of its sales with its excess capacity in the congestion region and the rest of its sales with its efficient capacity in the non congestion region. This claim would only need to be formalized in the energy program and as such it would be aggravating expected congestion in comparison to an energy program that would reflect efficient dispatch.

Table 6.6 *Yearly surplus simulations for system redispatch with cost pass-through to generators, assuming DEC2*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain of game [mln €/yr]
Surplus Gen NN	431.68	431.68	431.68	431.68	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen RN	451.65	451.65	451.65	451.65	0.00
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZH	305.24	258.28	305.24	258.28	0.00
ZH C_{off}	21.59	20.00	21.59	17.28	2.94
ZH non C_{off}	207.79	162.43	207.79	165.15	-2.94
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	165.89	165.89	165.89	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus TSO	0.00	0.00	0.00	0.00	0.00
Surplus Gen NL	1354.46	1307.50	1354.46	1307.50	0.00
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

In case congestion arises and the excess capacity is constrained off, the generator will enjoy the associated benefits. In case congestion arises and the excess capacity is not constrained off, the generator may simply run efficient dispatch, i.e. redispatch such that the efficient production capacity in the non congestion region is dispatched and the excess capacity in the congestion region is undispatched. This would result in the additional benefits of being compensated for excess capacity in system redispatch model and additional revenues from sales of transmission rights in market agent model. In case no congestion arises, again the generator may redispatch internally and ends up with an efficiently dispatched portfolio sourcing its sales. In other words, the DEC2 game can not result in any loss of surplus and is likely to result in additional surplus. In addition it does not require any deviation from normal operational planning, except claiming dispatch of high-cost facilities in the congestion area in the energy programme.

In Table 6.6 the surplus results of the DEC2 strategy for the system redispatch with cost pass-through to generators are presented. On the left-hand side, results for DEC gaming are presented, while competitive results and the gain are presented on the right-hand side. It may be observed that surplus for the constrained off generators in the congestion area Zuid-Holland increases with some 2.94 mln € yearly in case of strategic behaviour. The TSO ends up with an equal increase of costs, but increases the congestion fee accordingly, so that the non constrained off generators face an equal decrease of surplus.

Table 6.7 *Yearly surplus simulations for the market agent approach, assuming an efficient secondary market with DEC2*

	Strategic Dispatch [mln €/y]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain of game [mln €/yr]
Surplus Gen NN	431.68	436.19	431.68	436.19	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	4.51	0.00	4.51	0.00
Surplus Gen RN	451.65	474.99	451.65	474.99	0.00
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	23.34	0.00	23.34	0.00
Surplus Gen ZH	305.24	228.19	305.24	228.19	0.00
ZH C_{off}	21.59	-0.87	21.59	-3.19	2.31
ZH non C_{off}	207.79	153.21	207.79	155.52	-2.31
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	168.13	165.89	168.13	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL not C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	2.24	0.00	2.24	0.00
Surplus TSO	0.00	0.00	0.00	0.00	0.00
Surplus Gen NL	1354.46	1307.50	1354.46	1307.50	0.00
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

Table 6.7 presents results for application of DEC2 by the constrained off generators in the congestion region Zuid-Holland in case of the market agent approach with an efficient secondary market. On the left-hand side results for strategic behaviour are presented, followed by competitive results. On the right-hand side the gain of the DEC2 strategy is reported. For the particular case of Scenario A, one may observe that the DEC2 strategy pays off as surplus for the constrained off generators in the congestion area Zuid-Holland increases with some 2.31 mln € yearly in case of strategic behaviour. The increase goes directly at cost of the surplus of the non constrained off generators in the congestion region as these generators buy the transmission rights.

In this assessment it has been assumed that DEC gaming only occurs when congestion is expected. It is conceivable however that DEC2 is applied, such that congestion is induced. In these instances the impact of DEC2 would be significantly higher.

6.5 Strategic price bidding in the constrained on market

The constrained on market offers opportunities to generate revenues with capacity that would otherwise have been idle. In case of uniform pricing in the constrained on market, as is assumed in the market redispatch model, the hybrid redispatch market and the market agent approach, opportunities to submit bids above marginal cost of production may arise. As such this market does not differ much from the day ahead market. In case there is sufficient competitive pressure, i.e. in case there are a large number of independent generators serving this market, increased bidding may not arise as one runs the risk of losing volumes to lower bids of competitors. However if only a limited number of generators is in the position to bid in to the constrained on market, unilateral market power or (tacit) collusion may arise. In general, the number of generators serving this market will be somewhat limited during instances of high national demand, like during peak hours. Particularly during such periods increased bids in the constrained on markets may occur.

For the particular case of the system redispatch with cost pass-through to generators, one should take note of the fact that a pay-as-bid market is assumed. Since pay-as-bid at levels of marginal cost of production does not generate any profits, one may assume that increased bidding will take place for this particular system at any rate. Much like the reduced constrained off bids in case of the system redispatch with cost pass-through to generators, bids in the constrained on market may go up to the expected highest bid accepted, essentially transforming the pay-as-bid market into a uniform pricing market and the opportunities for strategic price bidding in the constrained on market are much like the opportunities for the other congestion management systems.

Table 6.8 *Yearly surplus simulations for Hybrid Redispatch with increased constrained on bidding at 110% of marginal cost of production*

	Strategic Dispatch [mln €/yr]	Strategic Redispatch [mln €/yr]	Competitive Dispatch [mln €/yr]	Competitive Redispatch [mln €/yr]	Gain [mln €/yr]
Surplus Gen NN	431.68	450.36	431.68	436.19	14.17
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN not C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	18.68	0.00	4.51	14.17
Surplus Gen RN	451.65	498.05	451.65	474.99	23.06
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN not C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	46.40	0.00	23.34	23.06
Surplus Gen ZH	305.24	233.54	305.24	233.54	0.00
ZH C_{off}	21.59	0.00	21.59	0.00	0.00
ZH not C_{off}	207.79	157.69	207.79	157.69	0.00
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.89	172.76	165.89	168.13	4.63
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL not C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	6.87	0.00	2.24	4.63
Surplus TSO	0.00	-47.20	0.00	-5.35	-41.85
Surplus Gen NL	1354.46	1354.70	1354.46	1312.85	41.85
Total Surplus	1354.46	1307.50	1354.46	1307.50	0.00
Redispatch Costs		-46.96		-46.96	

None of the congestion management systems considered intrinsically mitigates the risk of the occurrence of this behaviour. As an illustration of the impact of increased constrained on bidding in a uniform pricing constrained on market, Table 6.8 presents the surplus results for such a strategy in case of the hybrid redispatch model, assuming bids to match 110% of the marginal costs of production. Such a moderate bid level can be considered as a realistic bid level that is not likely to be detected so that the regulator would not have a strong case for further investigation.

In Table 6.8 the simulated surplus results for the increased constrained on bid strategy are presented on the left hand side. Additionally the results for competitive behaviour are presented as well. Finally on the right-hand side the gain of the strategy compared to competitive bids is presented for each of the agents involved. One may observe that a significant increase of surplus results for the constrained on generators, amounting to a gain of 41.85 mln € for the constrained on generators combined. These increases in generator surplus go at cost of the TSO surplus, as in this particular redispatch model the TSO is exposed to the cost of redispatch, and the TSO ends up with an additional loss of 41.85 mln €.

6.6 Strategic volume bidding in the constrained on market: capacity withholding

Capacity withholding can be an effective strategy in uniform pricing markets seeking to increase prices, at cost of loss of volume. In case of generators offering lots of volume, it may be beneficial to withhold some capacity in order to increase prices at cost of a relatively small loss of volume. Typically this strategy pays off if significant price increases are achieved through withholding a relatively small proportion of overall market volume. In the particular case of Scenario A, the supply curve is relatively stable in the volume range at hand so that this strategy offers relatively limited potential in this scenario. None of the congestion management systems considered intrinsically mitigates the risk of the occurrence of this behaviour.

One may note that a comparable strategy could be applied in the wholesale market. As generators in non congestion regions expect higher pay-off in the constrained-on market than in the wholesale market, such behaviour may even be induced by congestion management in the face of congestion. Generators may be incentivised to retain capacity for the purpose of bidding into the constrained on market. As a result, wholesale market prices may increase which may be considered as a spill-over of constrained on power prices into the wholesale market. Furthermore, as low-cost generation in non congestion regions is retained and wholesale prices go up, more capacity in the congestion regions is sold in the wholesale market, aggravating the congestion problem.

6.7 Conclusions

In this chapter several gaming opportunities were assessed. Here, gaming opportunities involve adjusted bidding behaviour regarding both price and/or volume, such that systematically higher profits result for the bidder than would be the case if this agent behaves as it is assumed in the analysis presented in the Chapter 5 on competitive behaviour. As a pragmatic approach, a variety of strategies is explored on the basis of systematic analysis of generic opportunities for each of the classes of generators participating in the congestion management systems considered, i.e. the constrained off, non-constrained off and constrained on generators. If appropriate, increasing complexity of the ownership structure is considered on the basis of international experience regarding strategic behaviour in the face of congestion management. The results of the assessment are presented in

. Here the signs indicate if the congestion management system considered performs well (+), moderate (+/-) or poor (-) regarding the critical aspect considered. None of the systems considered shows an intrinsic mechanism to inherently mitigate the risk of either strategic price or volume bidding in the constrained on market, so that these gaming opportunities are not presented in this table.

The system redispatch with cost pass-through to generators shows some susceptibility to strategic price bidding in constrained off market. In particular, reduction of bid levels offers some opportunity to increase profitability for the constrained off generators in this system. Constrained off generators may increase the profitability by reducing their bid levels down to the level of the highest bid level expected to be accepted, effectively transforming the pricing structure of the constrained off market from a pay-as-bid structure to a uniform price structure. As a result congestion costs increase so that the congestion fee increases and surplus is transferred from the non constrained off generators to the constrained off generators in the congestion region. For the Scenario considered there is relative little room for this type of strategic behaviour, i.e. the resulting transfer of surplus is relatively limited in comparison to the overall distributive effects of the congestion management system. One should be aware that other realisations of generation investment, fuel prices and the like could result in a higher impact. Conclusively opportunities for increasing profitability for both constrained off and non constrained off generators in case of system redispatch with cost pass-through to generators seem relatively limited though not absent. On the other hand system redispatch with cost pass-through to generators shows to be more susceptible to strategic volume bidding in the constrained off market, i.e. DEC games. As this system provides for compensation of loss of volume in case of being constrained off, the system incentivises generators to overstate production volume in the congestion area, both increasing congestion and increasing the constrained off volume compensation. The associated increase in surplus for the constrained off generators goes at cost of the non-constrained off generators as the costs are passed on by the TSO in the form of the congestion fee.

Table 6.9 *Robustness of the congestion management systems considered against gaming*

	System Redispatch Model with cost pass-through to generators	Market Redispatch Model	Hybrid Redispatch Model	Market Agent approach, with efficient secondary market
Strategic price bidding in constrained off market	+/-	-	-	+
Strategic volume bidding in the constrained off market	-	+	+	-

The market redispatch model is more sensitive to strategic price bidding in the constrained off market. In case of market redispatch the congestion fee equals the marginal bid, i.e. the lowest constrained off bids accepted, in the congestion rights market. This provides for an opportunity to reduce the constrained off bids such that a lower congestion fee results. Decreasing the constrained off bids comes at the risk of being constrained off since the lowest bids are accepted. This strategy therefore requires unilateral market power or (tacit) collusion in order to harness the joint generator interest to decrease the congestion fee while not compromising the individual generator interest not to be constrained off. In these instances, the opportunity to game the congestion fee could in theory result in a reduction down to zero which would result in a high transfer of surplus from the TSO to the non constrained off generators. In practice however, one should expect the potential for reduction of the congestion fee not to be much larger than some 10% in order to go undetected by the regulator. The market redispatch system is not likely to offer opportunities for strategic volume bidding in the constrained off market, as the constrained off generators are not compensated for being constrained off in any way.

Similar to the market redispatch model, the hybrid redispatch model is sensitive to strategic price bidding in the constrained off market. Also in this system the congestion fee equals the highest constrained off bids accepted in the congestion rights market. Decreasing the constrained off bids comes again at the risk of being constrained off since the lowest bids are accepted. As in case of the market redispatch system, this strategy therefore requires unilateral market power or (tacit) collusion in order to harness the joint generator interest to decrease the congestion fee while not compromising the individual generator interest not to be constrained off. In these instances, the opportunity to game the congestion fee could in theory result in a reduction down to zero which would result in a high transfer of surplus from the TSO to the non constrained off generators. One should expect the potential for reduction of the congestion fee not to be much larger than some 10% in order to go undetected by the regulator. One may note that if this system would be altered, such that congestion fees are set as in the system redispatch with cost pass-through to generators, these considerations no longer apply. The hybrid redispatch system is not likely to offer opportunities for strategic volume bidding in the constrained off market, as the constrained off generators are not compensated for being constrained off.

The market agent approach is insensitive to strategic price bidding in the constrained off market, as no explicit constrained off market occurs in this system. Though of course the same argument applies to strategic volume bidding in the constrained off market, the system may be stated to be sensitive to strategic volume bidding in the constrained off market in the sense that it pays off to overstate nominated production in order to receive a higher amount of transmission rights on the basis of the pro rata assignment.

Conclusively, the assessment of gaming opportunities indicates that the different congestion management systems may be distinguished mainly on the basis of the robustness against gaming in the constrained off market, as none of the systems provides for incentive mechanisms that reduce the opportunity for gaming the constrained on market. System redispatch with cost pass-through to generators shows some susceptibility to both strategic price and volume bidding in the constrained off market though the simulations suggest that there is limited potential for these strategies. In addition one may note that within the context of system redispatch with cost pass-through to generators, these games involve transfer of surplus between generators only. Both the market and hybrid models show potential for gaming the TSO through strategic price bidding for the congestion fee. In the case of the hybrid system this notion is aggravated by the fact that the TSO is partially exposed to the redispatch costs and requires revenues from the congestion fee to cover for this exposure. Though the simulations indicate high transfers of surplus resulting from these games one should be careful to acknowledge that the simulations indicate a maximum transfer of surplus within the context of the scenario considered. In practice the transfers are likely to be in the order of 10% of the reported results as higher levels would probably lead to interventions from the regulator. Finally the market agent approach is mainly susceptible to strategic volume bidding of the constrained off market as it induces overstatement of production in order to retrieve higher volumes of transmission rights.

7. Conclusions

The results in Chapter 4 indicate that the benefits of the new connection policy for both consumers and producers are significant. The increase in total benefits, in particular consumer benefits, is robust under a variety of scenarios. However, congestion is likely to occur so that redispatch costs will be made due to reallocation of generation capacity from constrained areas to non-constrained areas. Hence, the benefits of consumers and/or producers may be reduced by the resulting redispatch costs. The simulations suggest that benefits are significantly higher than the redispatch costs, even when assuming that the transmission capacity expansion plans in both the Northern region of the Netherlands and Zuid-Holland will not be realized. The absolute value of benefits and costs may be dependent on the supply, demand, and fuel and CO_2 price developments. However, the benefits are shown to be roughly an order of magnitude higher than the redispatch costs; hence the conclusion is expected to be robust. On the other hand, one should note that the redispatch costs in Chapter 4 are based on the assumption that efficient redispatch takes place. Inefficiencies in redispatch, potentially caused by the congestion management system, may lead to an increase in the redispatch costs. In addition, the simulations assume no spill-overs from the congestion management system into the wholesale market.

In Chapters 5 and 6, four congestion management systems are evaluated, namely system redispatch with cost pass-through to generators, market redispatch, hybrid redispatch and the market agent approach. Each of these systems is shown to have several advantages and disadvantages. System redispatch is susceptible to strategic volume bidding of the constrained off market and, as a consequence, potentially shows limited redispatch efficiency. In addition, this system is not efficient in the long term as it may provide for an incentive to renounce decommissioning of older production capacity with high marginal cost of production that would be eligible for decommissioning in case no transmission limitations applied. Market redispatch potentially results in strong redistribution of income at the expense of the generators and as a consequence holds a significant risk of spill-over of congestion costs into the wholesale market. In addition it is highly susceptible to strategic price bidding of the constrained off market. The hybrid redispatch system leaves TSO exposed and is susceptible to strategic price bidding of the constrained off market as well. The short term efficiency of the market agent approach depends heavily on the rise of an efficient secondary market; hence it seems recommendable to consider additional measures in support of the rise of such a market from a regulatory and institutional perspective. As an alternative one could consider hybrid redispatch with cost pass-through to generators. Such a system effectively addresses the shortcomings of both the system redispatch with cost pass-through to generators and the hybrid redispatch system that are highlighted in the analysis.

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Appendix A The COMPETES model

To analyse the competition on wholesale electricity markets and between different national markets ECN developed the COMPETES[18] model. COMPETES covers twenty European electricity markets, i.e. Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom. Here Denmark is divided into two parts that belong to two different non-synchronised networks, while Luxembourg is added to Germany, because there is generally no congestion between them. The model assumes that these markets can influence the market prices in other markets.

The model is able to simulate strategic behaviour (oligopolistic competition) while considering the effect of transmission constraints between countries. This strategic behaviour is based on the theory of Cournot competition and Conjectured Supply Functions (CSF) on electric power networks[19]. The strategic behaviour of the generation companies is reflected in the conjectures each company holds regarding the supply response of rival companies. These response functions simulate each company's expectations concerning how rivals will change their electricity sales when prices change in response to the company's actions; these expectations determine the perceived profitability of capacity withholding and other strategies. The Cournot model represents one possible conjecture: that rivals will not change their outputs; COMPETES can also simulate the other extreme: that a company's actions will not change price (price taking behaviour). CSFs can be used to represent conjectures between these two extremes. COMPETES can also represent different systems of transmission pricing, among them fixed transmission tariffs, congestion-based pricing of physical transmission, netting restrictions, and auction pricing of interface capacity between countries.

Virtually all generation companies in the twenty countries are covered by the input data of the model. The user can specify which generation companies are assumed to behave strategically and which companies will be allocated to the so-called 'competitive fringe' (i.e. the price tak-ers). The model calculates the equilibrium behaviour of the generators - and the resulting out-comes - by assuming that they simultaneously try to maximise their profits. By considering the extremes of Cournot and perfectly competitive equilibria, as well as CSF equilibria between those extremes, the robustness of conclusions to assumptions about degrees of competitive behaviour can be assessed.

[18] COMPETES stands for COmprehensive Market Power in Electricity Transmission and Energy Simulator. This model is based on the theory of Cournot and Conjectured Supply Functions (CSF) competition on electric power networks, and is developed in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University, Baltimore, Maryland, USA.

[19] The basic transmission-constrained Cournot formulation underlying COMPETES was first presented in Hobbs (2001), while the conjectured supply function generalization appeared first in Day et al. (2002). COMPETES itself, including alternative transmission pricing formulations, is presented and applied in Hobbs et al. (2003a, 2003b). COMPETES has been used to analyze issues such as effects of proposed mergers (Scheepers et al., 2003), market coupling (Hobbs et al., 2005), and the EU Emissions Trading System (Neuhoff et al. 2006, Sijm et al. 2005, 2006, 2006a, 2006b). More recently, analyses have been undertaken of the representation of DC interties with Nordpool and the full EU20 power market (Hobbs et al. 2008, Lise et al. 2008). COMPETES can consider the market power mitigating effects of forward energy contracts as well as the effects of company conjectures concerning how transmission prices are affected by company actions. The formulation of transmission constrained oligopoly used by COMPETES is widely used in the industry, with the original Hobbs (2001) formulation being cited over 60 times by archival journal articles.

With regard to consumer behaviour, the present version of the model considers 12 different levels of demand, based on the typical demand during three seasons (winter, summer and autumn/spring) and four time periods (super peak, peak, shoulder and off-peak). The 'super peak' period in each season consists of the 240 hours with the highest sum of the loads for the twenty considered countries. The three other periods have equal numbers of hours and represent the rest of the seasonal load duration curve. Altogether, the twelve periods represent all 8760 hours of a year. The consumers are assumed to be price sensitive by using decreasing linear demand curves depending on price. The number and duration of periods and the price elasticity of demand in different periods are user-specified parameters.

Transmission of electricity among countries is constrained both by power transmission distribution factors (PTDF), which is a linearised "DC load flow" representation of the transmission network, and path-based restrictions, which reflect the contractually allowed flows among countries. The linearised load flow model recognizes the existence of controllable DC lines between nonsynchronized markets (UK, UCTE, and Nordpool). Interface constraints in the path-based restrictions include constraints between individual pairs of countries, as well as multicountry interfaces (for instance, aggregate exports from Germany to the Netherlands and to France are constrained). Note that the physical line capacity is generally larger than the contractually permitted amounts and this difference is also reflected in the COMPETES model.

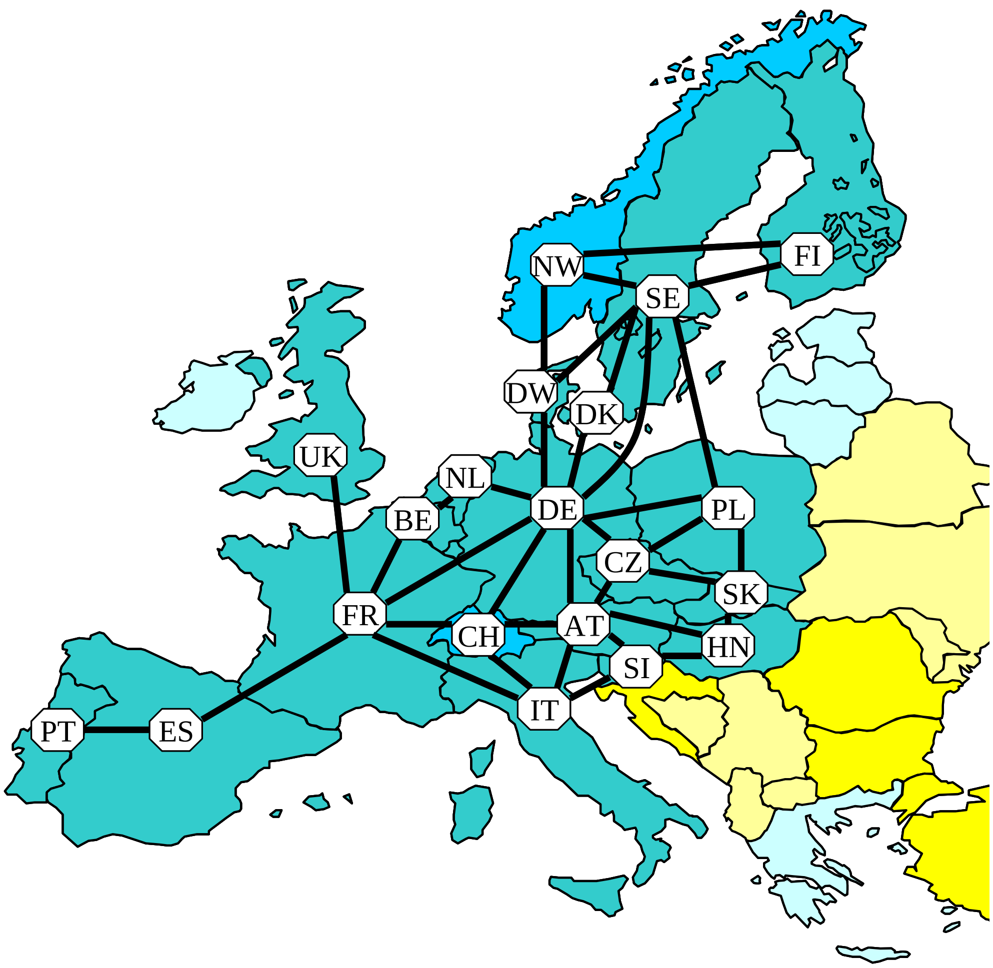

Figure A.1 *Nodal representation of EU20 in COMPETES*

The recent version of COMPETES model also includes detailed representation of German grid as illustrated in.Figure A.2. The detailed reprentation of the German grid is used in the joint study of ECN and The Bremen Energy Institute of the Jacobs University Bremen on the basis of the analysis for the impact of future power generation and transmission capacity developments in European electricity markets on the German power market.

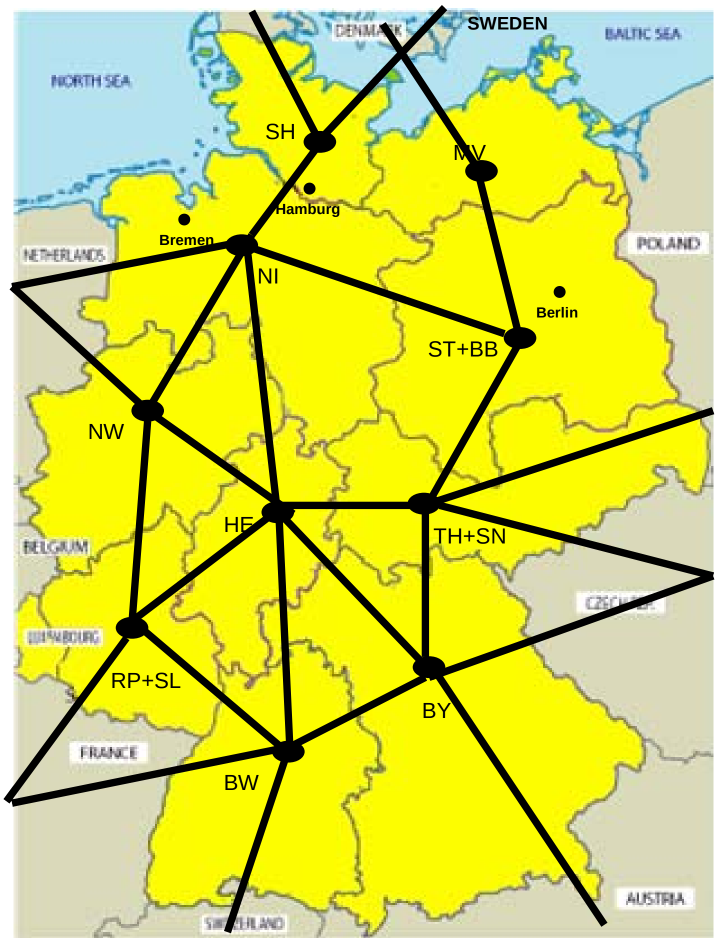

Figure A.2 Multi-*node representation of Germany in COMPETES*

Appendix B Scenario Assumptions

B.1 Baseline Scenario Assumptions (Scenario A):

Generation Capacity Investments in the Netherlands: According to TenneT list, 18.4 GW of generation capacity will definitely be connected to the high voltage grid by 2010. In addition to this capacity, the total amount of announced new generation capacity currently known to TenneT in future adds up to 30.5GW, though only a proportion of this total is planned to come online before 2012. In addition, announcements of new generation capacity do not guarantee that these investments will be realised. In the process towards realisation of an investment in generation capacity a multitude of go/no-go moments occurs.

In order to assess development of generation investment in the Netherlands, ECN tracks planning, permitting and contracting for known generation investments plans. Such information is used for the development of scenarios for generation investment, like the scenarios presented in the actualisatie referentieramingen. For the purpose of this study, the baseline scenario assumes a generation investment scenario in line with the actualisatie referentieramingen, combined with the latest insights in planning, permitting and contracting for known investments plans and information from TenneT. Under baseline scenario for new connection policy, total new/replaced generation capacity realized in near future is assumed to be 12.2 GW respectively. This is in line with the best estimate (Scenario B) System Adequacy Forecast (SAF) scenario of UCTE.

Table B.1 *The new generation capacity investments assumed in Scenario A*

Region	Technology		Scenario A (Baseline) New Generation Capacity [in GW]	
		2010 Capacity	New	Decommissioned
Ring (RN)	Wind offshore	0.1	1.5	
	Gas	6.4	1.7	-0.6
	Coal	2.7		
Northern Netherlands (NN)	Wind offshore		1.5	
	Gas	3.8	1.4	
	Coal		1.6	
Zuid-Holland (ZH)	Gas	2.2	1.6	
	Coal	1.0	2.9	
Zeeland	Gas	1.3		
(ZL)	Coal	0.4		
	Nuclear	0.5		
Total		18.4	12.2	-0.6

Table B.2 *Assumed new generation (I) and decommissioned/replaced (D) capacities in the neighbouring countries*

	DE		BE		FR		UK		NOR	
Technology	New	Decom	New	Decom	New	Decom	New	Decom	New	Decom
Gas	6.5		3.00		4.9		10.50		0.8	
Coal	18.6		1.10	-0.25		-3.6	1.10	-8.10		
Lignite	2.8									
Nuclear		-8.7		-0.40	1.6			-3.80		
Wind - onshore	3.5		0.70		6.1		1.30			
Wind - offshore	11.9		0.70		0.3		4.50		1.3	
Hydro									1.3	
Biomass			0.02				2.10		0.1	
Oil				-0.70				-2.60		-0.2
Total Increase	34.6		4.7		9.3		5		3.3	

*Generation capacity investments in the neighbouring countries***:** In addition to the generation capacity developments in the Netherlands, investments in new generation capacity is also expected in the neighbouring countries in near future. The new generation capacity assumptions given in Table B.2 for the neighbouring countries are in between the conservative (Scenario A) and best estimate (Scenario B) UCTE SAF. Since we would like to see the impact of additional generation capacity in the Netherlands, we fix the new generation capacities in the neighbouring countries in all the scenarios as given in Table B.2.

*Internal and Border Transmission Capacities in Dutch Network***:** The capacities of transmission lines within Netherlands represent the *net transfer capacity* (NTC). TenneT's has investment plans to increase transmission capacity in the Northern Netherlands and Zuid-Holland regions. Scenario A assumes post- realization of project Randstad 380 zuid and pre-realization of investment plans of the Northern Ring compared to the realization of the generation capacity investments in these regions. Table B.5 gives the internal secure transmission capacities or NTC values from Zuid-Holland and Northern Netherlands regions assumed for Scenario A.

In addition, there are two types of limitations of transmission between the Netherlands and the neighbouring countries. One is the total import/export limitations between the Dutch electricity market and the neighbouring countries determined by TSOs on the basis of safe operational capacity limits. Figure 3.1 represents the safe import/export capacities of the Netherlands assumed for Scenario A to E. Another limitation at the border is the individual secure transport capacity of each transmission corridor between the Netherlands and the neighbouring countries, which are presented in the network representation of multiple node simulations for each future scenario in Appendix C.

*Demand growth in the North-western Europe***:** Next we give the assumptions for demand growth in Scenario A based on the UCTE System Adequacy Forecast. The demand level assumptions represent 2015 values and are fixed for all the scenarios.

Table B.3 *Assumed demand in the Netherlands and the neighbouring countries*

	Growth rate per year [10%]	Demand (TWh)
NL(HV-grid)	1.99	112
DE	0.31	590
BE	1.77	105
NW	0.80	133
FR	1.06	526
UK	0.86	389

Source: UCTE System Adequacy Forecast

Fuel and CO_2 Prices: Fuel and CO_2 prices are taken from the baseline scenario of Actualisatie Referentieramingen (2009). Fuel price assumptions are fixed in all the scenarios as given in Table B.4 whereas CO_2 price is varied in Scenario E.

Table B.4 *Fuel and CO_2 prices*

	NL	BE	GER	FR	UK
Coal [€/GJ]	2.0	2.0	2.2	2.0	2.0
Gas [€/GJ]	6.1	6.1	6.1	6.1	6.1
CO_2 price [€/tonne]	35	35	35	35	35

Source: Daniels et al., 2009

B.2 Scenarios Assumptions of Domestic Transmission Capacity Investments within Netherlands: Scenarios A1-A3

For an indication of the impact of the realization of internal transmission capacity investment plans for the Northern Ring and the Randstad Zuid, the realization of internal transmission capacity assumptions for Dutch network in Scenario A is varied. Table B.5 gives an overview of the corresponding domestic transmission capacities assumed for each scenario.

Table B.5 *The scenarios for realization of future internal transmission capacity investment plans*

Explanation of Scenarios		Transmission Capacity [MW]	
		NN-RN	ZH-RN
Scenario A	Only the investment plans for Northern Ring is realized	4170	2600
Scenario A1	None of the investments plans are realized	2670	2600
Scenario A2	Both investment plans are realized	4170	5800
Scenario A3	Only the investments plans for Randstad Zuid is realized	2670	5800

B.3 Scenarios Assumptions of Domestic Generation Capacity Investments within Netherlands: Limited and Moderate Generation Investments

Limited generation investment: If new connection policy is not implemented, the new connections will be limited. In this Scenario, it is assumed that limited generation capacity investments is about 3.2 GW in total, of which 1.7 GW fuel-based power plants and 1.5 GW offshore wind are connected to the ring. In addition, 640 MW of gas-fired capacity is expected to be replaced by a more efficient capacity.

Moderate investment scenario (Scenario B): Under the new connection policy, a moderate assumption for total new/replaced generation capacity realized may be 8.9 GW which is largely in line with the conservative (Scenario A) System Adequacy Forecast (SAF) scenario of UCTE.

The comparison of the generation investment scenarios with the baseline scenario is given in Table B.6.

Table B.6 *The existing generation capacity connected to HVG in the Netherlands by 2010 and assumed new generation capacities for current and new systems between 2010-2012*

Region	Technology		Current System Limited New Generation Capacity [GW]		New System Expected New Generation Capacity [GW]			
			Limited		Moderate		High	
		2010 Capacity	New	Decom	New	Decom	New	Decom
Ring (RN)	Wind offshore	0.1	1.5		1.5		1.5	
	Gas	6.4	1.7	-0.6	1.7	-0.6	1.7	-0.6
	Coal	2.7						
Northern Netherlands (NN)	Wind offshore				1.5		1.5	
	Gas	3.8			1.4		1.4	
	Coal						1.6	
Zuid-Holland (ZH)	Gas	2.2			0.9		1.6	
	Coal	1.0			1.9		2.9	
Zeeland (ZL)	Gas	1.3						
	Coal	0.4						
	Nuclear	0.5						
Total		18.4	3.2	-0.6	8.9	-0.6	12.2	-0.6

B.4 Scenario Assumptions of More Wind Power Generation in North-western Europe: Scenario C

An average wind turbine output in winter is assumed to be 45% of capacity for offshore - and 36% for onshore wind parks in the baseline scenario. In Scenario C average winter turbine output is assumed to be 60% for offshore wind and 45% for onshore wind parks. As a result, the wind power generation increases by approximately 30% in the Northwest European countries consisting of the Netherlands, Germany, UK, Belgium, and Norway.

B.5 Scenario Assumptions of Increased Secure Transmission Capacity at Northern German border: Scenario D

Scenario A assumes maximum secure transmission capacity between the Northern Provinces of the Netherlands (NN) and the North of Germany (NW) to be 880MW whereas Scenario D assumes increased secure transmission capacity between the Northern Provinces of the Netherlands (NN) and the North of Germany (NW) set at 1345 MW. In both of these scenarios it is assumed that Germany would solve its own congestion problem and there is sufficient internal transmission capacity within Germany.

B.6 Scenario assumption for low CO_2 price: Scenario E

Fuel price assumptions are fixed in all the scenarios as given in Table B.4 whereas CO_2 price is varied at moderate level of 35 €/ tonne in Scenarios A-D and low level of 20 €/ tonne in Scenario E.

Appendix C Figures indicating congestion and flows for Scenarios A-E

In this Appendix, overview of import/export flows for single and multiple node simulations are given. In the figures, the following graphical representation is used:

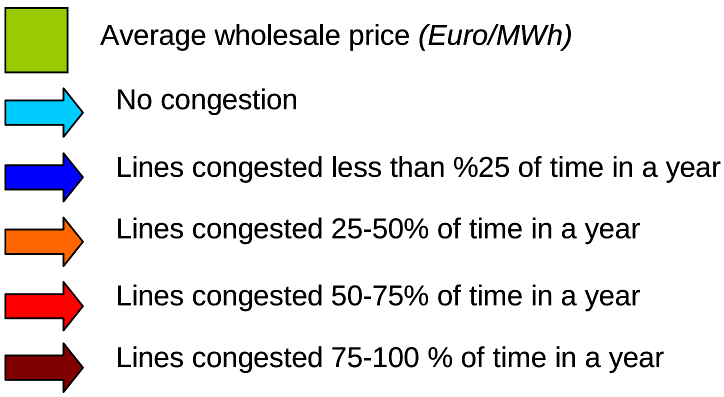

Figure C.1 *The representation for direction of flows and congestion in the figures*

Single-Node Simulation results:

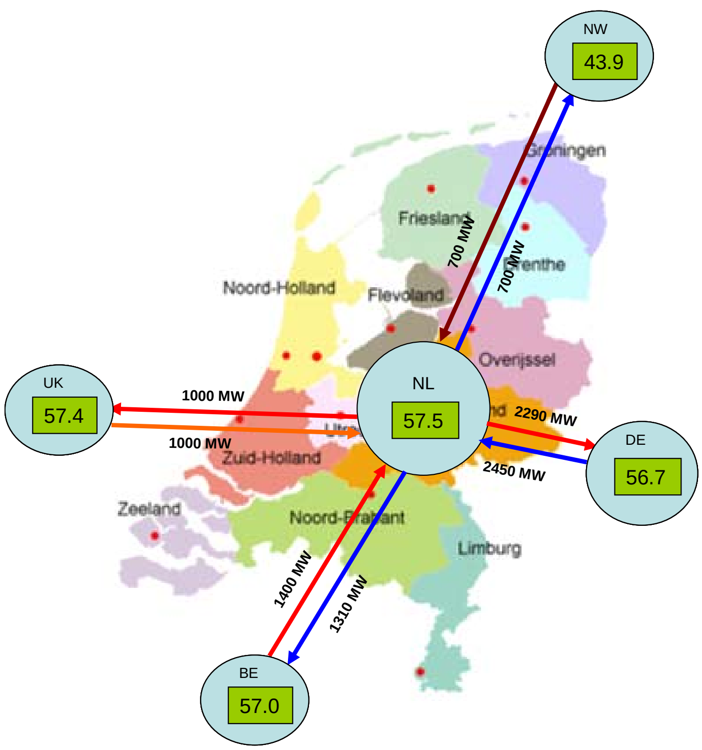

Figure C.2 *Exchange flows between Netherlands and the neighbouring countries in limited new generation capacity scenario under current system*

Scenario B
Low Generation Investment

Scenario A
Moderate Generation Investment

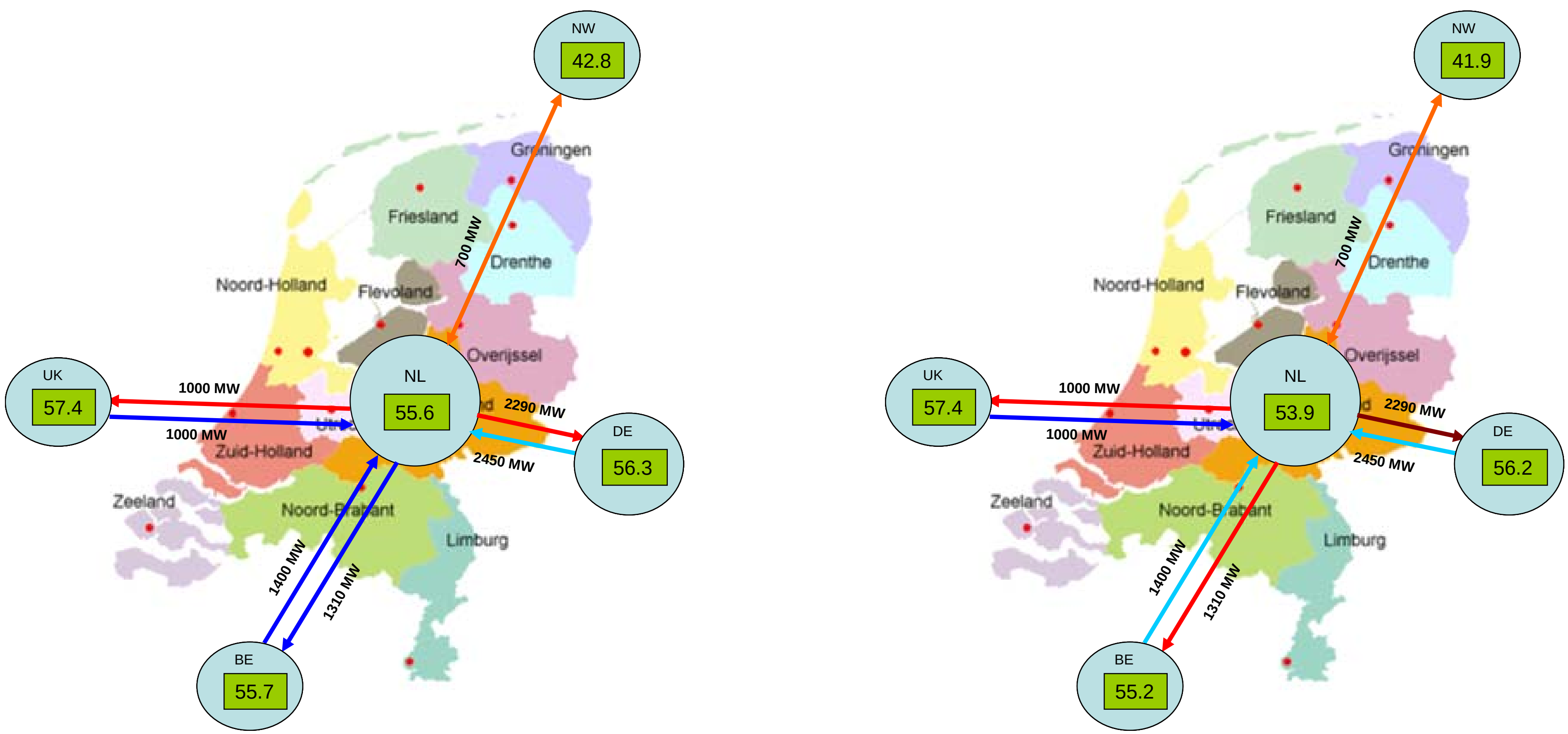

Figure C.3 *Exchange flows between Netherlands and the neighbouring countries in low or moderate generation investment scenarios under new system*

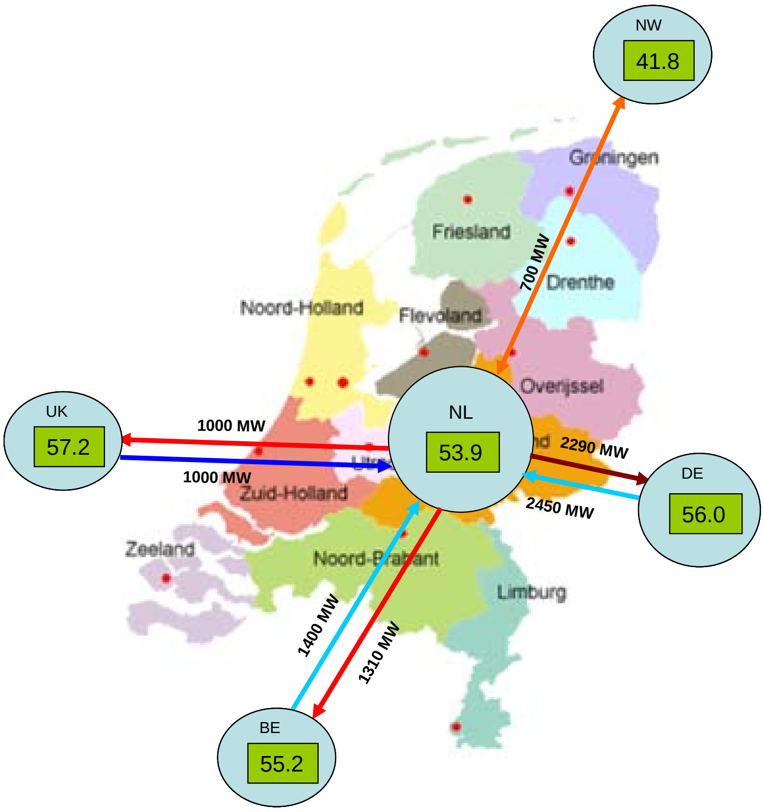

Figure C.4 *Exchange flows between Netherlands and the neighbouring countries in moderate generation capacity with high wind power generation scenario*

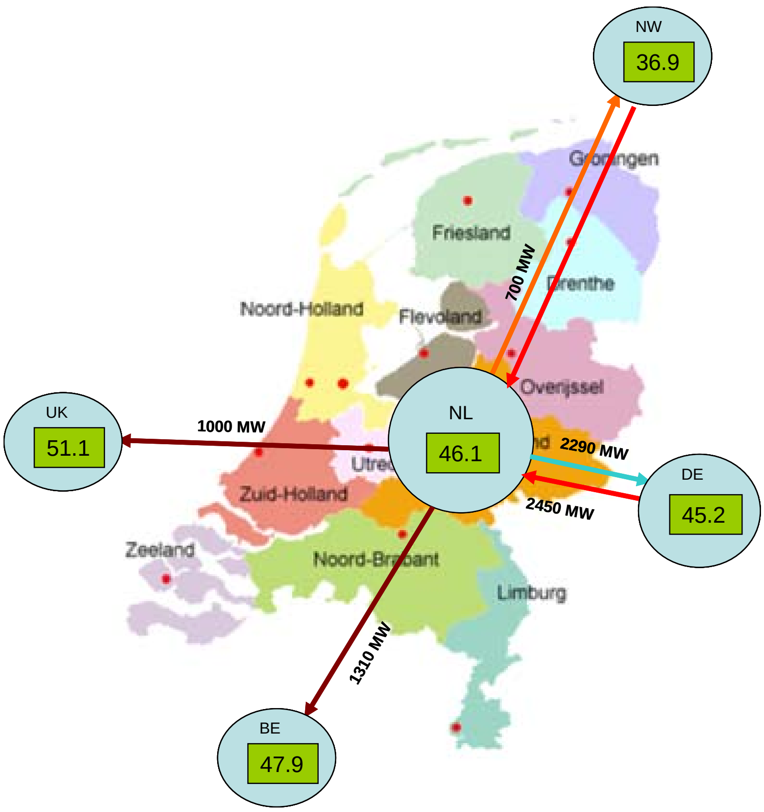

Figure C.5 *Exchange flows between Netherlands and the neighbouring countries in moderate generation capacity and low CO_2 price scenario*

Multiple-Nodes Simulation Results:

Scenario A
Moderate Generation Investment

Scenario B
Low Generation Investment

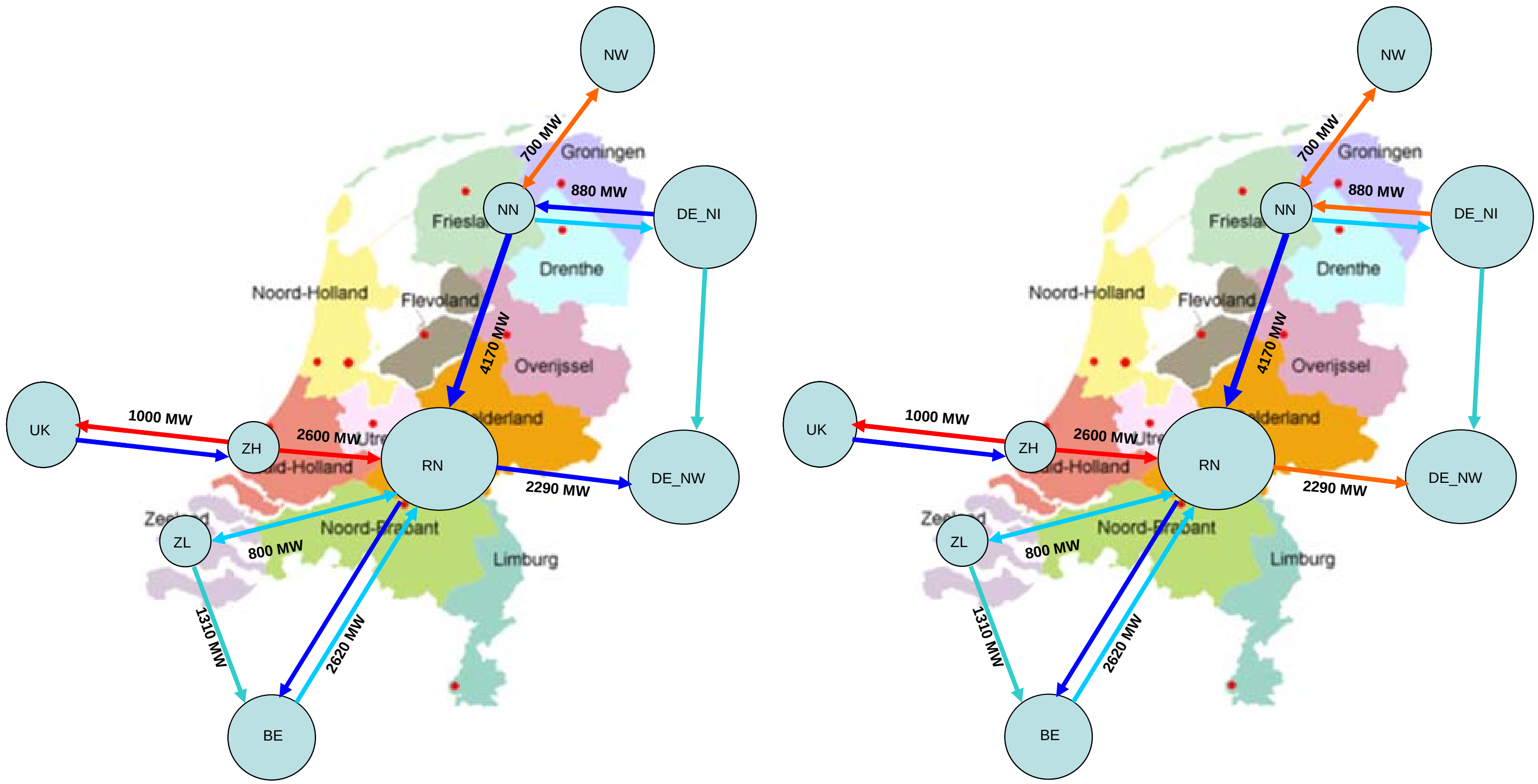

Figure C.6 *The congestion pattern in Dutch grid under low or moderate generation investment*

Scenario C
High Wind Availability

Scenario D
High NTC between NL and DE

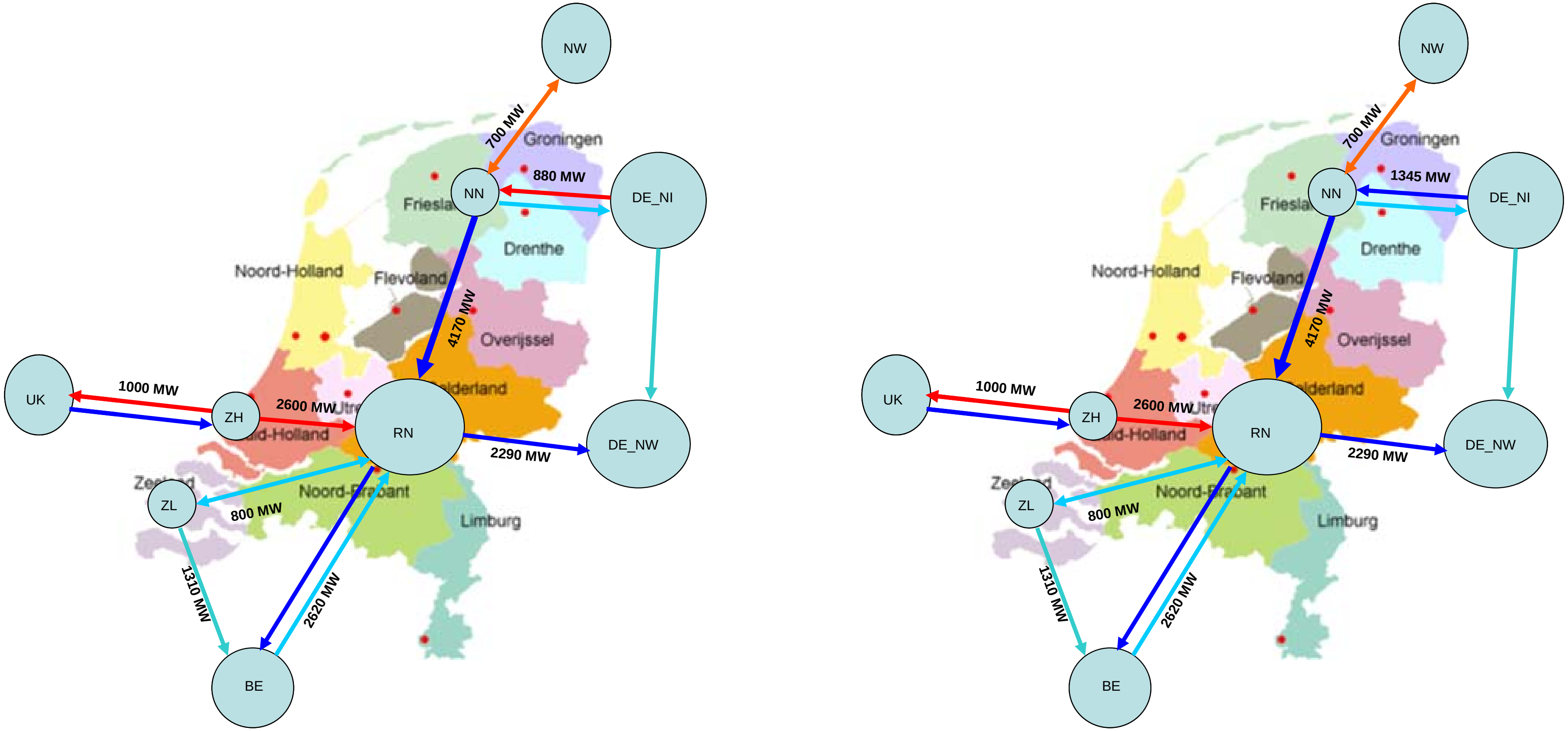

Figure C.7 *The congestion pattern in Dutch grid with high new generation capacity under high wind power generation or higher NTC scenario*

Scenario E
Low CO_2 price

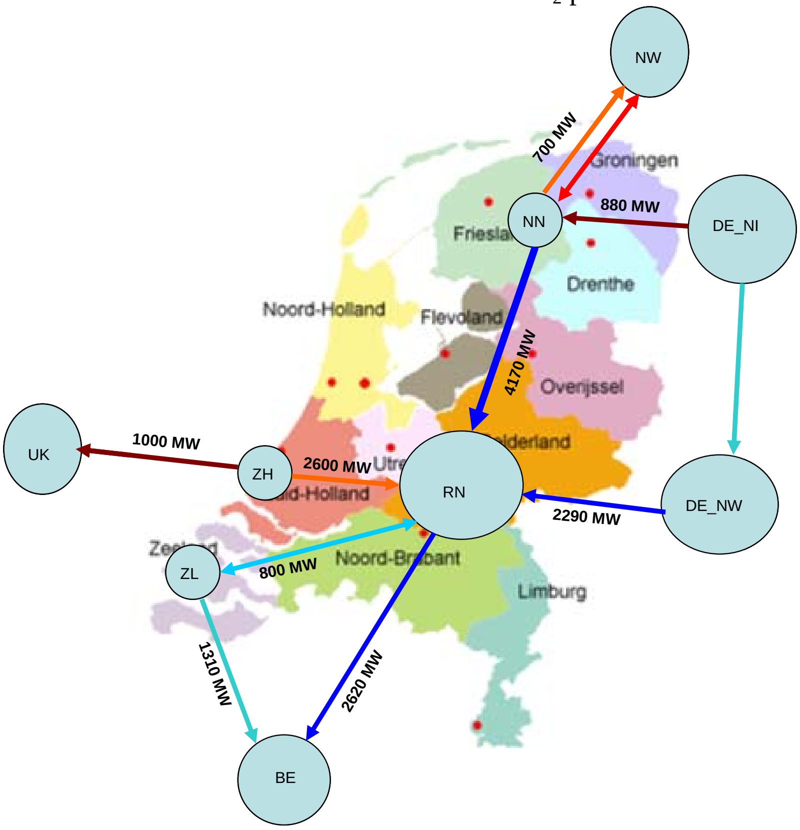

Figure C.8 *The congestion pattern in Dutch grid with moderate generation investment under low CO_2 price scenario*

Appendix D Analysis of Congestion Management under Non-Strategic Behaviour for Scenarios B and C

Table D.1 *Yearly surplus distributions under four congestion management systems for Scenario B (Low Generation Investment)*

		Delta after Redispatch [mln €/yr]			
	Dispatch [mln €/yr]	System Redis-patch	Market Redis-patch	Hybrid Redis-patch	Market Agent
Surplus Gen NN	353.95	0.00	0.00	0.00	0.00
NN C_{off}	0.00	0.00	0.00	0.00	0.00
NN non C_{off}	0.00	0.00	0.00	0.00	0.00
NN C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen RN	542.20	0.00	0.01	0.01	0.01
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	0.00	0.01	0.01	0.01
Surplus Gen ZH	266.80	-30.11	-171.03	-63.97	-30.12
ZH C_{off}	23.43	-6.64	-62.58	-23.43	-11.04
ZH non C_{off}	74.33	-23.48	-108.45	-40.54	-19.08
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	194.21	0.00	0.00	0.00	0.00
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus TSO	0.00	0.00	140.91	33.85	0.00
Surplus Gen NL	1357.16	-30.11	-171.02	-63.96	-30.11
Total Surplus	1357.16	-30.11	-30.11	-30.11	-30.11
Redispatch Costs		-30.11	-30.11	-30.11	-30.11

Table D.2 *Change of surplus as % of total redispatch costs for Scenario B (Low Gen. Invest.)*

	System Redispatch [%]	Market Redispatch [%]	Hybrid Redispatch [%]	Market Agent [%]
Surplus Gen NN	0	0	0	0
NN C_{off}	0	0	0	0
NN non C_{off}	0	0	0	0
NN C_{on}	0	0	0	0
Surplus Gen RN	0	0	0	0
RN C_{off}	0	0	0	0
RN non C_{off}	0	0	0	0
RN C_{on}	0	0	0	0
Surplus Gen ZH	-100	-568	-212	-100
ZH C_{off}	-22	-208	-78	-37
ZH non C_{off}	-78	-360	-135	-63
ZH C_{on}	0	0	0	0
Surplus Gen ZL	0	0	0	0
ZL C_{off}	0	0	0	0
ZL non C_{off}	0	0	0	0
ZL C_{on}	0	0	0	0
Surplus TSO	0	468	112	0
Surplus Gen NL	-100	-568	-212	-100
Total Surplus	-100	-100	-100	-100

Table D.3 *Yearly surplus distributions under four congestion management systems for Scenario C (High Wind)*

	Dispatch [mln €/yr]	Delta after Redispatch [mln €/yr]			
		System Redispatch	Market Redispatch	Hybrid Redispatch	Market Agent
Surplus Gen NN	477.22	0.00	1.42	1.51	1.50
NN C_{off}	0.00	0.00	-0.02	0.00	0.00
NN non C_{off}	42.77	0.00	-0.06	0.00	0.00
NN C_{on}	0.00	0.00	1.51	1.51	1.51
Surplus Gen RN	500.16	0.00	22.98	22.98	22.98
RN C_{off}	0.00	0.00	0.00	0.00	0.00
RN non C_{off}	0.00	0.00	0.00	0.00	0.00
RN C_{on}	0.00	0.00	22.98	22.98	22.98
Surplus Gen ZH	303.09	-36.02	-322.93	-68.83	-61.96
ZH C_{off}	20.89	-4.19	-98.73	-20.89	-19.52
ZH non C_{off}	206.34	-31.83	-224.20	-47.94	-42.44
ZH C_{on}	0.00	0.00	0.00	0.00	0.00
Surplus Gen ZL	165.28	0.00	1.45	1.45	1.45
ZL C_{off}	0.00	0.00	0.00	0.00	0.00
ZL non C_{off}	0.00	0.00	0.00	0.00	0.00
ZL C_{on}	0.00	0.00	1.45	1.45	1.45
Surplus TSO	0.00	0.00	261.05	6.87	0.00
Surplus Gen NL	1445.74	-36.02	-297.08	-42.89	-36.02
Total Surplus	1445.74	-36.02	-36.02	-36.02	-36.02
Redispatch Costs		-36.02	-36.02	-36.02	-36.02

Table D.4 *Change of surplus as % of total redispatch costs for Scenario C (High Wind)*

	System Redispatch [%]	Market Redispatch [%]	Hybrid Redispatch [%]	Market Agent [%]
Surplus Gen NN	0	4	4	4
NN C_{off}	0	0	0	0
NN non C_{off}	0	0	0	0
NN C_{on}	0	4	4	4
Surplus Gen RN	0	64	64	64
RN C_{off}	0	0	0	0
RN non C_{off}	0	0	0	0
RN C_{on}	0	64	64	64
Surplus Gen ZH	-100	-896	-191	-172
ZH C_{off}	-12	-274	-58	-54
ZH non C_{off}	-88	-622	-133	-118
ZH C_{on}	0	0	0	0
Surplus Gen ZL	0	4	4	4
ZL C_{off}	0	0	0	0
ZL non C_{off}	0	0	0	0
ZL C_{on}	0	4	4	4
Surplus TSO	0	725	19	0
Surplus Gen NL	-100	-825	-119	-100
Total Surplus	-100	-100	-100	-100