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# AN INTEGRATED APPROACH TO MODEL REDISPATCH AND TO ASSESS POTENTIAL BENEFITS FROM MARKET SPLITTING IN GERMANY

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**Abstract**

Future congestion management is one of the major market design issues in the European electricity market. In the light of the sharp increase in redispatch measures seen within the last years, the importance of an efficient management of network congestion increases particularly in Germany. Against this background, we develop an integrated approach to model (re)dispatch for Germany in detail while considering interactions with neighbouring countries. Compared to 2011, our findings indicate a much more critical network situation in Germany for 2015. We identify increased RES production, resulting imports and exports, delays in grid extension and the impacts of the nuclear phase-out (leading to an amplified north-south congestion problem) as main drivers for the nearly doubling of redispatch volumes in 2015. We show that market splitting can potentially contribute to a secure grid operation and leads to a significant reduction of redispatch volumes (59%) according our model calculations. We state that market splitting can of course not be the 'one and only solution' but an interim approach to manage upcoming congestion in Germany in times when grid expansion has not yet been completed and that the implementation of market splitting can also serve as an alternative to grid extension within less congested areas.



*Keywords: redispatch, congestion management, market design, market splitting*

*JEL-Classification: Q40, Q47, Q49*



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# 1 Introduction

Germany's accelerated nuclear phase out, increasing intermittent renewable electricity (RES) production and a grid not keeping pace with these developments as well as increasing international trading activities are challenging the European electricity transmission grids and cause increasing difficulties for TSOs in daily grid operation. While redispatch in Germany was rather exceptional in the past, congestion management and especially redispatch are now more and more necessary to secure grid stability. Several congestion schemes such as nodal, zonal and uniform pricing combined with redispatch but also market coupling are currently discussed in academic literature and policy making.

According to textbook economic theory, the first-best answer for an efficient congestion management is market splitting through nodal pricing (cf. Hogan 1992) as nodal prices reflect not only marginal generation costs but take also the costs of grid constraints into account. However, a timely implementation in Germany or Europe seems unrealistic for several reasons - notably due to the need for a German or European-wide ISO. The implementation of alternative bidding areas with regard to physical transmission constraints, or in other words: zonal pricing as e.g. implemented in the Scandinavian market Nordpool, could be a preferable interim solution to deal with the increasing congestion in Germany (cf. also Breuer et al 2013). No ISO is needed and a faster implementation of the mechanism is to be expected.

In order to be able to evaluate different congestion management schemes for Germany, first the development of the congestion situation and the corresponding redispatch volumes in Germany have to be modelled adequately. Yet, we face two main challenges: on the one hand modelling redispatch requires a very detailed modelling of the unit commitment and dispatch and the resulting electricity flows with a high temporal resolution - leading to a (computational demanding) hourly mixed-integer unit commitment model for Germany. But on the other hand the stand-alone modelling of Germany is insufficient as the intermittent production of RES, changes in market design (like the implementation of zonal pricing in Germany) and grid expansion substantially influence electricity flows within the entire ENTSO-E grid. To deal with those conflicting requirements, we develop an integrated modelling approach for modelling congestion and redispatch in Germany while considering interactions with neighbouring countries.

The focus of our case study is on Germany in 2015. Beside the evaluation of the congestion situation from a system security and an economic point of view, we analyse potential benefits from market splitting and highlight main issues posing challenges to the successful design and implementation of zonal pricing in Germany.

The paper is organized as follows. After a short review of the relevant literature focussing on the modelling of redispatch and congestion management (cf. section 2), we describe our methodology including the dispatch models and the load flow approximation in section 3. The indicators chosen to analyse the impact of market splitting on security of supply and economics are discussed in section 4. The scenario description and the data assumptions made for our case study are summarised in section 5. Our results are shown in section 6 where we evaluate changes in the congestion situation in Germany from 2011 to 2015 and also the impacts of the implementation of market splitting. Section 7 concludes.

## 2 Literature review

Future congestion management is one of the major market design issues in the European electricity market. The framework guidelines on capacity allocation and congestion management for electricity (CACM) as published by ENTSO-E (2012b) are a major step to pave the way for an efficient congestion management for whole Europe. Due to increasing RES feed-in, the accelerated nuclear phase out and insufficient grid expansion, congestion management in Germany is of particular interest.

But so far, it is not possible to investigate a full European system with a high (hourly) temporal resolution – due to the high dimensionality of the resulting mixed integer optimization problem (cf. also Breuer et al. 2013). The modelling of redispatch volumes and costs involves necessary but appropriate simplifications. For instance, Burstedde (2012) uses the cost-minimizing European linear investment and DC grid model NEULING to quantify the difference in total system costs between a first-best nodal and a second-best zonal electricity market design for Europe. Within this context also redispatch costs are calculated. While the high temporal resolution (8760 hours a year) and the geographical representation of the core European model regions[1] seem to be adequate simplifications with regard to the European focus of the study, the linear programming approach allows only to model the dispatch of power plant groups and not a unit-wise modelling what is especially important with regard to unit-specific constraints like on-/off-status, minimum run times or minimum generation. Furthermore the missing intertemporal optimisation of redispatch leads to an

[1] The core regions (CWE, Switzerland and Austria) are represented by 79 nodes which are connected via 434 lines. Neighbouring regions like Great Britain and the Scandinavian countries are in each case considered by country nodes.

overestimation of ramping costs. As already stated by the author herself: "However, redispatch is modelled by the hour such that ramping costs are overestimated in comparison to an intertemporal optimization. This is especially true if structural congestion requires continuous redispatch" (cf. Burstedde 2012 p. 6). With focus on Germany, Kunz and Zerrahn (2013) analyse the impacts of different degrees of coordination between TSOs within a generalized Nash game on redispatch costs and volumes. Although the hourly resolution of the model, the nodal representation of the German transmission network and the dispatch optimization on block level are suitable for the modelling of redispatch, the authors do not take into account limitation of units through unit commitment restrictions like ramping constraints, minimum generation and online/offline times. In addition the abstraction from intertemporal decisions like the not endogenously modelled dispatch of pumped-storage plants leads to a lower level of flexibility within the system. Furthermore direct interactions with neighbouring countries are not considered - import and exports are given exogenously.

Furthermore, several studies focused in recent time especially on the German or European area and examined the impacts of alternative bidding zones in Germany. For instance Breuer et al. (2012) analyse the impacts of alternative bidding zones on the Austrian transmission grid and critical transmission lines in Germany, Czech Republic and Poland for 2010. Their key finding is that a splitting of the joint German/Austrian market area would, among other things, not lead to a significant reduction in redispatch costs. Based on a qualitative analysis for 2011, Consentec and Frontier Economics (2011) also state that the economic impacts of a potential splitting of Germany into two bidding zone are very limited. Furthermore Thema consulting group and E-Bridge (2012) analyse the impact of internal congestion within Germany and Great Britain especially for the value of new interconnectors with Norway under the assumption of the establishment of three bidding zones in Germany and two market zones within Great Britain in 2018. They also find that the effects of market splitting are limited as there is only low internal congestion in Germany. As a result, this does not affect German prices significantly within the study. However, they assume grid extensions according to the electricity grid expansion act (EnLAG 2011) are completed as planned and do therefore not take into account current delays[2] in grid extension. Moreover the internal congestion in Germany depends strongly on the assumed expansion of RES – e.g. for 2015 the German TSOs expect more than 19 TWh generation only from offshore wind parks (cf. Amprion GmbH et al. 2012a). Hence, feed in from offshore wind is not included within studies with a time frame aligned to 2015, resulting in much lower internal congestion in Germany.

[2] cf. (Bundesnetzagentur 2012a)

So far there has hence been no study using a very detailed dispatch optimization model for Germany under consideration of intertemporal unit commitment restrictions and under usage of an hourly rolling planning approach as well as the impacts on imports and exports. The present paper does not aim at finding the optimal splitting of the German electricity market but to model redispatch in a more suitable way with acceptable computation times - and to investigate to what extent market splitting can potentially contribute to congestion management and to the integration of RES.

# 3 Methodology: an integrated approach

## 3.1 Modelling approach

Modelling redispatch for Germany and assessing the impact of market splitting as accurately as possible requires on the one hand a very detailed modelling of the power plant dispatch and the resulting electricity flows with a high (hourly) temporal resolution. A high temporal resolution for an entire year is needed especially to consider fluctuations in load flows, renewable infeeds and resulting redispatch including seasonal variations. On the other hand varying production of RES, changes in market design and grid expansion in Germany can have substantial impacts on electricity flows not only within Germany. Changes in the German electricity market design like the introduction of market splitting will influence the whole European power system in terms of national power prices and resulting imports and exports – and will therefore also induce indirect impacts on redispatch. Thus the stand-alone-modelling of Germany with fixed imports and exports is inappropriate in the context of modelling redispatch. Hence, an intertemporal Europe-wide, nodal, mixed-integer unit commitment model with hourly resolution under usage of the rolling planning approach would be the best way to meet all these requirements. But obviously, such a huge model would be very difficult to handle due to exploding computation times. We therefore develop an integrated modelling approach as represented in Figure 1 that optimises redispatch for Germany in acceptable computation times while the most important impact factors on redispatch are considered in an adequate way.

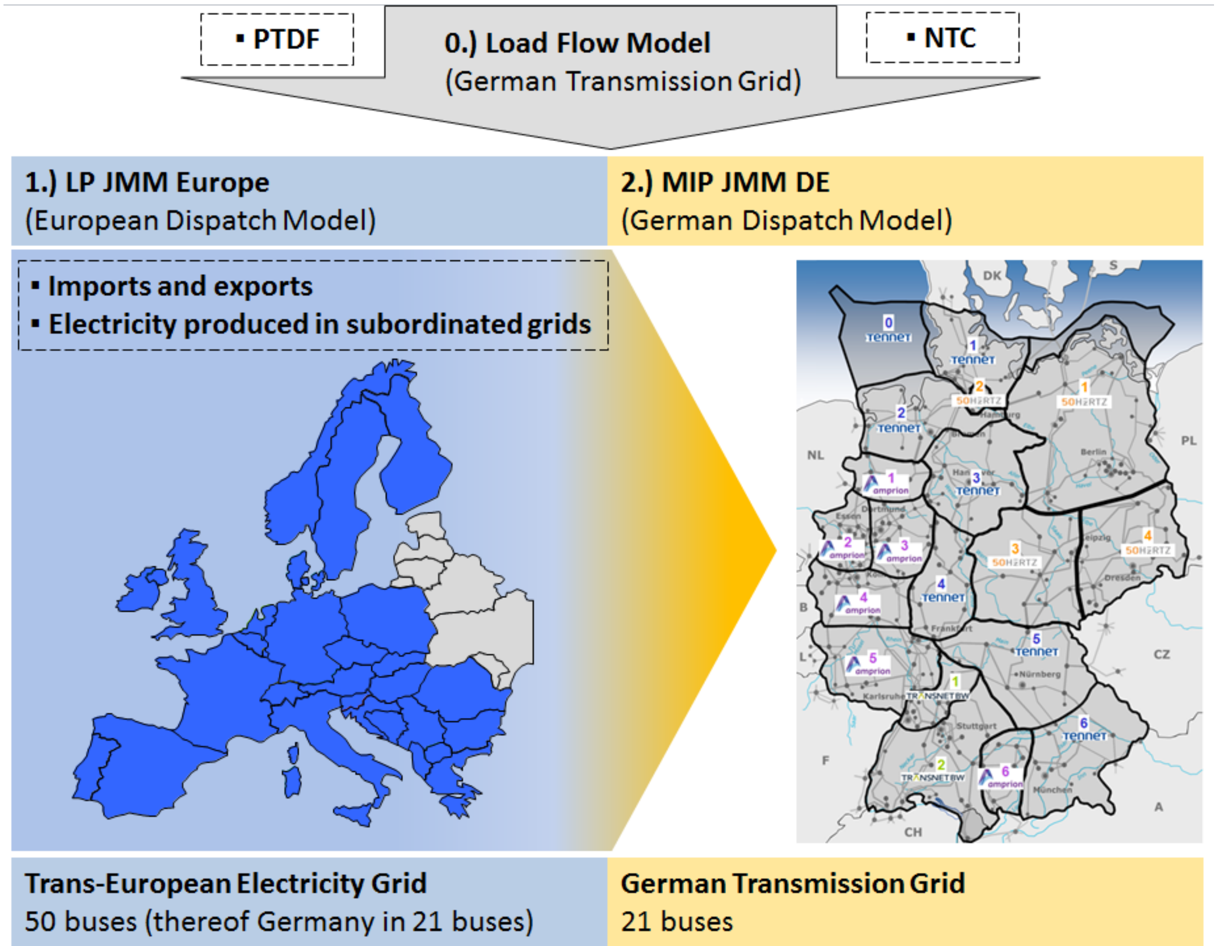


Figure 1: Model framework and geographical scope

The basic idea is to combine two model variants of the scheduling[3] model WILMAR (cf. section 3.3): a basic linear model variant for Europe (LP JMM Europe) and a more detailed one for Germany (MIP JMM DE). First the power plant commitment and dispatch is optimized within LP JMM Europe under simplified assumptions for most European countries (cf. Figure 1), using NTC values to model transactions between countries. By usage of a European PTDF matrix, the modelled European trading flows are then transformed ex post into physical import and export flows. The import and export flows are then used as input factors for the more detailed MIP JMM DE, which focuses on the German transmission grid.

Small-scale power plants not directly connected to the transmission grid are a particular issue for the modelling. Those represent more than one third of the total generation in Germany, yet they are typically not used for redispatch measures. Therefore they are not modelled endogenously within MIP JMM DE, yet they are within LP JMM Europe.

[3] Note that we use the term *scheduling* to designate both *unit commitment* and *dispatch* decisions for power plants. Obviously, the linear programming model will not provide exact unit commitment decisions, but rather a continuous approximation labeled *capacity online* (cf. Weber et al. 2009, Tuohy et al. 2011 for more details).

Consequently, the electricity produced in underlying grids as modelled in LP JMM Europe is used to calculate the load at the transmission grid level (the so-called "vertical load") which is used in turn as input in MIP JMM DE.

The model LP JMM Europe hence assures that the main impacts of changes within Germany (RES, conventional power plants, grid extension, market design etc.) are considered within the highly meshed European electricity grid. The model variant MIP JMM DE complements this by modelling unit commitment and dispatch for Germany in detail together with the electricity flows as well as the resulting congestion and the corresponding redispatch measures .

While most European countries are represented by one bus, Germany is represented by 21 buses (according to the regional model of the German TSOs as used for instance in Amprion GmbH et al. 2009). Load flow approximation is done by using PTDFs and NTCs, both calculated within a load flow model for Germany (cf. Figure 1, part 0.), which is described within section 3.2.

The main benefits of our integrated approach to model redispatch (and assess potential benefits from market splitting) can be summarized as follows:

(1) Possible impacts of changes in Germany (like market splitting) on European electricity markets (that may influence redispatch in Germany) are considered. This aspect is very important especially with regard to the high degree of meshing in the European electric transmission grid.
(2) The mixed-integer, unit-wise modelling of the German dispatch assures an adequate modelling of the impacts of the unit commitment and dispatch of each German power plant unit on resulting flows, congestion and redispatch.
(3) The used rolling planning approach assures acceptable computation times and applies the intertemporal modelling of unit commitment for 8760 hours without the usage of simplifications like day types or typical hours.

With regard to the focus of our study the simplifications made (especially concerning the approximation of load flows[4]) appear from our point of view as acceptable compromise between the need for a very detailed modelling of power plant scheduling and electricity flows on the one hand and manageable calculation times on the other hand.

[4] No full nodal representation of the German transmission grid is used but an approximation by 21 buses within both scheduling models.

## 3.2 Load flow model

Within our approach, Germany is represented by 21 buses[5] and load flow approximation is done using power transmission distribution factors (PTDFs) and net transfer capacities (NTCs). In order to calculate PTDFs for the interconnections of the region electricity transport model and NTCs for the zonal border (between alternative bidding zones in Germany) a nodal load flow model for Germany is developed, containing the German extra high voltage grid (380 kV, 220 kV) with 601 buses (454 regular and 147 auxiliary buses), all generators with an installed capacity greater than 100 MW, offshore and onshore wind generation and the locational vertical load levels. The implemented DC security constrained optimal power flow (SCOPF) minimizes the overall costs of generation subject to generation capacities, maximum line flow constraints and violations that would occur during contingencies. All transmission lines and nodes of the German SCOPF model are based on the ENTSO-E Grid Map (cf. ENTSO-E 2012).[6] The electrical parameters of the transmission lines are estimated from the lengths, voltage levels and typical impedance values for overhead lines. The thermal limits are taken from Kiessling et al. (2003).[7] The surrounding countries are represented by country nodes that are connected to the German grid via cross border lines. According to the ENTSO-E-network map the load flow model includes 18 interconnectors to incorporate the imports and exports from respectively to all neighbouring countries[8].

For a more detailed description of the German SCOPF model used and also the calculation of PTDFs see Bucksteeg, Trepper, and Weber (2013). The calculation of NTC limiting the transport between the German buses corresponds to the calculation of the zonal transfer capacity (between the alternative market zones within the market splitting scenario) as described in section 5.3.2.

## 3.3 WILMAR Joint Market Model – description

The WILMAR Joint Market Model, a stochastic scheduling tool to analyse the impact of the fluctuating feed in from wind in energy markets, was originally developed within the

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[5] As mentioned within (Amprion GmbH et al. 2009) the regional transportation model is designed to highlight the long-distance transport of electricity between those load and generation centers. The regional model applies only to the representation of technical grid connections and carries physical flows. Trade flows between regions respectively buses are not subject of the representation.

[6] The data base was created in ArcGIS and the grid was validated based on several publicly available grid maps (cf. Umweltbundesamt 2013, TU Delft 2013, VDE 2012).

[7] As no detailed information on transformers is publicly available we assume a transformer with unlimited capacity in case of two geographically superposed 220 kV and 380 kV nodes. This implies that transformers do not cause congestions.

[8] Denmark, Sweden, Poland, Czech Republic, Austria, Switzerland, France, Luxembourg and the Netherlands

project Wind Power Integration in Liberalised Electricity Markets (WILMAR) supported by the EU (cf. Barth et al. 2006).[9]

The objective function being minimized is the overall variable cost of the system over the optimization period, covering fuel, $CO_2$, start-up and further variable costs. Multiple technical restrictions e.g. startup time, minimum up and down times, ramping rates, minimum and maximum generation and reserve targets are included. Beside electricity also heat demand has to be met in 8760 hours a year. The modeled market prices reflect the marginal generation costs. More detailed information about the scheduling model including all equations can be found in Weber et al. (2009), Tuohy et al. (2009), Barth et al. (2006) and Meibom et al. (2006).

As the modeling of redispatch depends strongly on the hourly load flows, this requires a very detailed modeling of the power plant dispatch notably of pumping storage plants. In this view, the usage of a model using day types or typical hours is inappropriate. Instead an intertemporal, hourly optimization of the unit-wise power plant dispatch as implemented within the WILMAR JMM is needed to model load flows and congestion in an adequate way and will be described in the following.

Within this study no load and wind forecast errors or unplanned plant outages are considered ("perfect forecast"). This is especially done to model the pure effect of grid constraints on redispatch. One may also argue that intraday trading (which is not explicitly taken into account in the model) and reserve markets handle large parts of the existing forecast error.

The planning horizon of the WILMAR JMM is up to 36 hours with hourly optimization. Thereby two decision problems can be distinguished:

- Day-ahead market for power trading (according to EPEX-based trading)
- Redispatch to relieve the remaining transmission grid restrictions (Intraday [10])

Rolling planning is shown in Figure 2 with rolling every 12 hours.[11] Starting at noon, the system is scheduled over 36 hours until the end of next day (Day 1). The power plant (re)dispatch is optimized every 12 hours again, based on the then available information. While the optimization for the day-ahead market does not take into account

[9] See www.wilmar.risoe.dk for more details. Further developments had been done within the EU projects SUPWIND www.wind-integration.eu and EWIS www.supwind.risoe.dk.

[10] Within this study the term *Intraday* is used to describe the planning loops after the day-ahead market in which the day-ahead schedule can be changed (re-dispatch) to relieve the remaining transmission constraints. Within this study the term *Intraday* does not refer to intraday markets, which are normally part of the electricity wholesale market and where electricity is traded to balance deviations from the day-ahead-schedule (e.g. due to forecast errors or power plant outages).

[11] Originally rolling planning has been done every 3 hours in WILMAR. But to avoid excessively high computation times we reduce the rolling to 12 hours.

transmission grid restrictions (consideration of bidding zones as copperplates), this happens intraday after day-ahead market closure, whereby units are up and down regulated (redispatched) compared to the day-ahead schedule. The unit commitment, i.e. whether they are operating or not, can also be changed intraday. When rolling forward, the state of the units at the end of the first planning loop of the previous optimization period is used as the starting state of the next optimization period, i.e., if rolling is done every 12 hours, the state of a unit (on or off and how long it has been on or off) at the end of hour 12 is used as the starting state for the next optimization. After rolling forward, the system is then planned until midnight of the following day, so that the system is optimized two times over a 24-hour period.

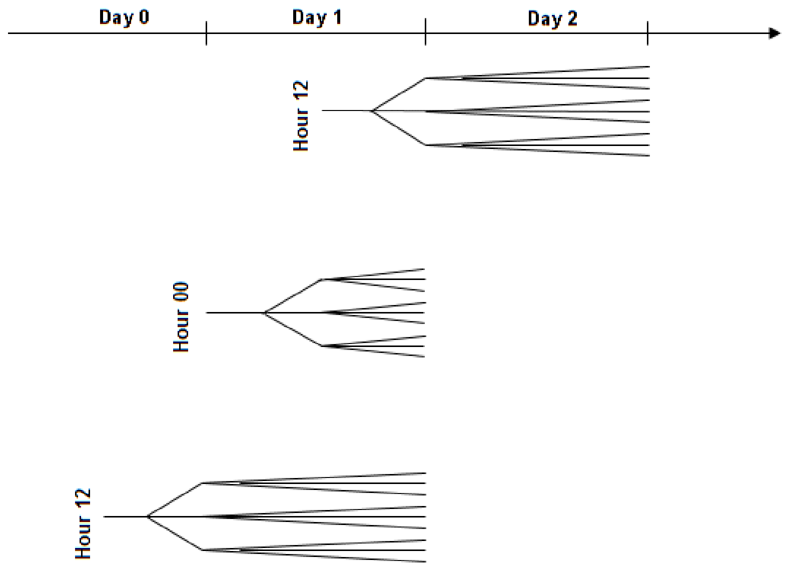


Figure 2: Rolling planning

Due to the high complexity of the scheduling model, we approximate load flows and dispatch by a trans-European-50 bus system to keep calculation times manageable. In line with the so-called “region model” of the German TSOs, the German transmission grid is represented by 21 buses, thereof 3 offshore buses (cf. Amprion GmbH et al. 2009).

In the following we describe the main equations that are relevant for the modeling of redispatch, especially the load flow equations. The equations shown relate to the model variant MIP JMM DE (German dispatch model) where load flow approximation is done using PTDFs and NTCs. Descriptions of the used indices, parameters and decision variables can be found in the appendix.

To ensure that the power flow $P_{r,r',t}^{TRANS,DAY-AHEAD}$ planned at the day-ahead market does not exceed the available day-ahead (transfer) capacity $L_{r,r',t}^{TRANS,DAY-AHEAD,MAX}$ between market zones, equation (1) is defined:

$$P_{r,r',t}^{TRANS,DAY-AHEAD} \leq L_{r,r',t}^{TRANS,DAY-AHEAD,MAX}$$

$$\forall (r,r') \in V, \forall t \in T \qquad (1)$$

After the day-ahead optimization of the power plant dispatch, physical transmission capacities $L_{r,r',t}^{TRANS,INTRADAY,MAX}$ are taken into account within the intraday loops. To calculate the power exchange between regions we use the PTDF approach that translates financial transactions between market participants into physical load flows. For the formulation of PTDFs for linear load flows see for instance Sauer (1981). In case that physical transmission resulting from the day-ahead dispatch exceeds physical transmission capacities, redispatch measures are needed.

The equations (2) and (3) therefore guarantee that the physical (intraday) flows do not exceed the available transmission capacity under consideration of the thermal, security constrained capacity restrictions $L_{r,r',t}^{TRANS,INTRADAY,MAX}$ of the transmission lines and the relevant PTDFs $ptdf_{r,r',r^*,t}$. They are applied for those time segments when the optimization describes intraday adjustments. At this moment in time the day-ahead variables $P_{r,r',t}^{TRANS,DAY-AHEAD}$ are fixed and only the intraday variables $P_{r,r',s,t}^{TRANS,INTRADAY,AC,+}$ are subject to optimization. Nevertheless the day-ahead decisions have to be included in the restrictions, because they impact the (over-)loading of the lines. The equations also include the possibility of DC connections and the possibility to reserve part of the transmission capacity for (non-spinning) reserves. Furthermore the possibility is also foreseen to turn off intraday changes to the power flows via the binary parameter $B^{TRANS,INTRADAY\_YES}$.

$$B^{TRANS,INTRADAY\_YES} \sum_{r^*} ptdf_{r,r',r^*,t} \left[ \sum_{r''} \left( P_{r^*,r'',s,t}^{TRANS,INTRADAY,AC,+} - P_{r^*,r'',s,t}^{TRANS,INTRADAY,AC,-} \right) \right.$$

$$\left. - \sum_{r''} \left( P_{r'',r^*s,t}^{TRANS,INTRADAY,AC,+} - P_{r'',r^*,s,t}^{TRANS,INTRADAY,AC,-} \right) \right]$$

$$+ B^{TRANS,INTRADAY\_YES} \left( P_{r,r',s,t}^{TRANS,INTRADAY,DC,+} - P_{r,r',s,t}^{TRANS,INTRADAY,DC,-} \right)$$

$$+B^{TRANS,NONSP\_YES}\sum_{r^*} ptdf_{r,r',r^*,t}$$

$$+\ B^{TRANS,NONSP\_YES} \cdot\ P^{TRANS,NONSP,DC}_{r,r',s,t}$$

$$+\sum_{r^*} ptdf_{r,r\prime,r^*,t}\left(\sum_{r''} P^{TRANS,DAY-AHEAD,AC}_{r^*,r'',t} - \sum_{r''} P^{TRANS,DAY-AHEAD,AC}_{r'',r^*,t}\right)$$

$$+\ P^{TRANS,DAY-AHEAD,DC}_{r,r',t}$$

$$\leq L^{TRANS,INTRADAY,MAX}_{r,r\prime,t}$$

$$\forall (r,r') \in V,, \forall t \in T, \forall s \in S \qquad (2)$$

$$B^{TRANS,INTRADAY_{YES}}\sum_{r^*} ptdf_{r,r',r^*,t}\left[\sum_{r''}\left(P^{TRANS,INTRADAY,AC,+}_{r^*,r'',s,t} - P^{TRANS,INTRADAY,AC,-}_{r^*,r'',s,t}\right)\right.$$
$$\left. - \sum_{r''}\left(P^{TRANS,INTRADAY,AC,+}_{r'',r^*s,t} - P^{TRANS,INTRADAY,AC,-}_{r'',r^*,s,t}\right)\right]$$

$$+B^{TRANS,INTRADAY\_YES}\left(P^{TRANS,INTRADAY,DC,+}_{r,r',s,t} - P^{TRANS,INTRADAY,DC,-}_{r,r',s,t}\right)$$

$$+B^{TRANS,NONSP\_YES}\sum_{r^*} ptdf_{r,r',r^*,t}$$

$$+\ B^{TRANS,NONSP\_YES} \cdot\ P^{TRANS,NONSP,DC}_{r,r',s,t}$$

$$+\sum_{r^*} ptdf_{r,r\prime,r^*,t}\left(\sum_{r''} P^{TRANS,DAY-AHEAD,AC}_{r^*,r'',t} - \sum_{r''} P^{TRANS,DAY-AHEAD,AC}_{r'',r^*,t}\right)$$

$$+\ P^{TRANS,DAY-AHEAD,DC}_{r,r',t}$$

$$\geq -\ L^{TRANS,INTRADAY,MAX}_{r',r,t}$$

$$\forall (r,r') \in V, \forall t \in T, \forall s \in S \qquad (3)$$

## 3.4 Differences between the European and German dispatch model

While most of the general characteristics and restrictions are the same within both dispatch models, some simplifications have been made to achieve manageable computational times. Table 1 summarizes the specific model assumptions. Modelling redispatch as accurately as possible requires a detailed modelling of electricity flows and explains the need for unit-wise generation modelling. Within MIP JMM DE the dispatch of each unit is modelled in much more detail but only the transmission network level and vertical load are considered.

Table 1: Specific model assumptions of the dispatch models

| *Specific model assumptions* | *LP JMM Europe (European dispatch model)* | *MIP JMM DE (German dispatch model)* |
|---|---|---|
| **Optimization** | Linear | Mixed-integer |
| **Dispatch** | Grouping of power plants | Unit-wise modelling |
| **Geographical scope** | Europe (ENTSO-E grid except Baltic states) and 21 regions in Germany | 21 regions in Germany and imports and exports as modelled within LP JMM Europe |
| **Demand scope** | Total demand | Vertical load (Focus on transmission network), calculated based on the modelled electricity production in subordinated grids |
| **Production scope** | All power plants | Power plants connected to the high-voltage transmission grid (and further power plants which are relevant for redispatch) |
| **District heating** | Consideration of district heating and resulting CHP operation restrictions | No consideration of district heating, CHP operation is set exogenously |
| **Load flow approximation** | NTC and ex-post load flow approximation using PTDF (from a European load flow model) | PTDF and corresponding line capacities (both derived from a nodal German load flow model (see section 3.2) |

# 4 Methodology: indicators for security of supply (SoS) and economic impacts

In order to evaluate the potential benefits of market splitting in Germany in 2015, we define both security of supply-related and economic indicators.

### 4.1 Security of supply-related indicators

We identify four main indicators to compare the security of supply respectively to measure the impact of market splitting on the system reliability of the German transmission grid for 2015: **number of congestion hours**, **number of congestion event hours**, **total congestion amount** and **total redispatch amount.**

**Congestion hours** are those hours in which redispatch is (still) needed to preserve system reliability – anywhere in the transmission system. The maximum number of congestion hours is 8760, the number of hours of a year. E.g. if there are two congested lines in one hour, only one congestion hour is counted.

**Congestion event hours** (CEH) are those hours in which redispatch is (still) needed to preserve system reliability. The number of (remaining) congestion event hours can exceed the hours of a year as each congestion event on each regional border is counted separately. E.g. if there are two congested regional borders in one hour, those are counted as two congestion event hours.

The **congestion amount** refers to the amount of energy scheduled after day-ahead market closure which cannot be transported due to limited physical transmission capacities. E.g. if the day-ahead market results in a specific hour lead to physical flows of 3,000 MW over the specific regional border Amp5/TnBW1 where the physical transmission capacity is limited to around 2,000 MW, the congestion amount in this hour would be 1,000 MWh.

The **redispatch amount** refers to the amount of energy that has to be re-adjusted (or in other words: re-dispatched) to remove congestion and keep up system security. As the amount of positive redispatch corresponds to the amount of negative redispatch all figures and tables that refer to modelled redispatch volumes apply to negative redispatch unless specified otherwise.

### 4.2 Economic indicators

In order to analyse also economic effects related to future congestions, we focus on the following economic indicators: **total redispatch costs, specific redispatch costs, mean day-ahead price (difference) and total system costs**.

Within the described model approach **total redispatch costs** can be interpreted as difference of total system costs of a network with (constrained) and without (copperplate) transmission constraints considered. While the copperplate-variant indicates the system costs for a scenario without any binding transmission constraints, the higher system costs within the constrained-variant occur due to redispatch measures needed to keep up the security of supply. To calculate the total redispatch costs we therefore run two model calculations for each scenario – one model run with Germany considered as a copperplate and another model run with consideration of transmission constraints within Germany[12] (after day-ahead market). It should be noted that the modelled redispatch costs have to be regarded as lower boundary[13] mainly due to costs minimization under perfect foresight (no forecast errors or plant outages). Costs for wind shedding are not included within the redispatch costs.

**Per-unit redispatch costs** are then calculated by taking the total redispatch costs divided by the total amount of redispatch (I) respectively the total amount of congestion (II).

The **mean day-ahead price difference** is calculated as price difference from the yearly average day-ahead prices of both market zones.

To derive statements about the effect of market splitting on the total welfare, we consider the difference between the **total system costs** with and without market splitting. But costs for wind shedding are not included within the total system costs since those have been set deliberately and arbitrarily high to make wind shedding the ultimate ratio in dispatch (as commended by the German renewable legislation).

# 5 Case study: development of redispatch and potential benefits from market splitting in Germany in 2015

## 5.1 Data

The analysis is done for 2015. Due to the full availability of data and the already performed backtesting (for the validation of the model and the input data within several projects[14]) the reference year is 2008.

[12] Despite of the zonal transfer capacity between both German market zones.

[13] To be more precise: in reality congestion can not only be removed by redispatch but also by changing the network status, what is not considered within our model. Therefore the amount of redispatch modelled could also be higher than redispatch done in reality. Nevertheless our model underestimates the amount of redispatch needed in reality from an overall perspective as the effect by the perfect forecast is considered higher. The comparison of the modelled redispatch and the redispatch seen in 2008 in reality (what has been done within some industrial projects) confirms this statement.

[14] E.g. within the German TSO redispatch study (cf. Schmitz, Frohmajer, and Weber 2012)

The current German market design related to renewable electricity is retained in all scenarios. In particular, this means that the (unlimited) priority of RES feed-in is retained and wind curtailment is only allowed for purposes of system security. Because of the large-scale expansion of RES, it is assumed that the curtailment of wind is also possible on the day-ahead market. The assumed costs for wind curtailment are 1,000 EUR/MWh. In general, the development of RES within all European countries is based on the national renewable action plans respectively UCTE (2009), for Germany the expectations of Amprion et al. (2012) are retained (cf. Table 2). Wind and solar production are modelled as exogenous production and are region-specific.

Table 2: RES production 2015 in Germany (in TWh)

| **RES** | **2015** |
|---|---|
| Wind onshore | 61.4 |
| Wind offshore | 19.0 |
| Photovoltaic | 49.5 |
| Total | 129.9 |

Based on the EWL database, which is continuously updated on the basis of publications and press reports, commissioning and decommissioning of conventional power plants in Europe are taken into account. For Germany, the power plant park 2015 is considered especially with regard to the power plant list published by the Bundesnetzagentur (2011). Table 6 in the Appendix shows the considered energy mix in the German scheduling model.

Given the currently known delays in grid expansion, the timeline for completion of all projects proposed under the DENA studies respectively the EnLAG (cf. Deutsche Energie-Agentur 2005, Deutsche Energie-Agentur 2010, Bundesnetzagentur 2012b) has been reviewed carefully for Germany.

A more detailed description of the used input data including the assumed fuel and $CO_2$ prices for 2015 can be found in the appendix.

### 5.2 Reference scenario

We consider two scenarios within this paper: the reference scenario and the market splitting scenario, both for 2015. The aim of the reference scenario, as kind of business as usual scenario, is to analyse and understand challenges and opportunities for German TSOs. The focus is thereby on congestion and redispatch associated with the increased RES production and the expected status of network expansion in Germany in 2015.

Within the reference scenario, it is assumed that the current market design in Germany is maintained until 2015 and congestion management is done via redispatch while transport restrictions within Germany are not considered in the day-ahead market (or in other words: Germany is treated as a copperplate), but exchange flows between countries are limited. The specific data assumptions made are explained in section 5.1 and in the appendix.

## 5.3 Market splitting scenario

In light of the challenging network situation in Germany in 2015, the market splitting scenario investigates the impacts of introducing market splitting as one possible measure to deal with upcoming congestion in the German (and European) electricity system. The focus is thereby on the security of supply-related and economic impacts of market splitting. When defining a market splitting scenario for Germany, two main challenges arise. The first one is the specific zonal delimitation. Obviously the zonal border (where the day-ahead market is split) should run along the main bottlenecks to 'catch' major congestions already on the day-ahead market and therefore reduce redispatch. Otherwise market splitting would not be very effective. The second challenge is then to determine the zonal transfer capacity that is provided for trading to the day-ahead market. In this context we are facing a trade-off between system security and market liquidity. The lower the zonal transfer capacity given to the day-ahead market, the higher the system security would probably be due to the fact that the restricted trading volume results in a lower utilisation of the generally congested lines between the market zones. But on the other hand, a too low zonal transfer capacity decreases the liquidity of the day-ahead market and results in potentially unused transmission capacity along the zonal border. Except for the market splitting, all specific data assumptions made in the market splitting scenario e.g. about the energy mix, RES and network expansion are the same as those applied in the reference scenario.

### 5.3.1 Delimitation of market zones

To determine new market zones for Germany at first the main bottlenecks in the German transmission grid need to be identified. The left part of Figure 3 shows the congestion amounts by regional border obtained in the reference scenario for Germany in 2015.

During the last years, the most congested line was the "Thüringer Waldleitung" (between the regions 50Hz3 and Te5, cf. Bundesnetzagentur and Bundeskartellamt 2012). Our model results confirm that this line also heavily congested in 2015.

Moreover, major congestions occur at the regional borders Amp2/Amp4 and Te5/TrBW1 in 2015. The German electricity market is split into two zones to deal with this increased congestion – a northern and a southern zone (marked in green in Figure 3) – along the two major bottlenecks 50Hz3/Te5 and Amp2/Amp4. As market liquidity in general decreases with more and smaller market zones, we do not consider a further market splitting along the third bottleneck Te5/TrBW1. It is worth mentioning that our model results show that congestion within this network area is also removed to a large part by the 2 zones-market splitting.
In addition Figure 3 shows that the highest part of (negative) redispatch required for system stability occurs within the northern regions of Germany.

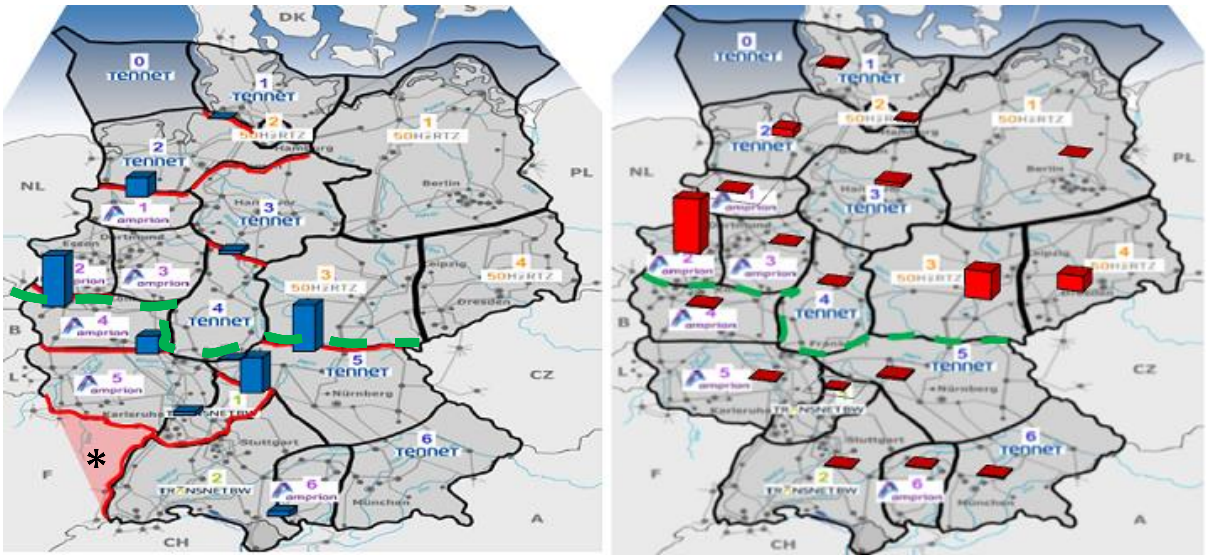

Figure 3: Congestion amount for the top 10 regional borders (left) and negative redispatch amount by region (right) for Germany (reference scenario 2015)

Notes: *Interconnection between regions Amp5 and TrBW2

### 5.3.2 Determination of zonal transfer capacity

There is an obvious trade-off between giving the market as much zonal (transfer) capacity as possible in order to use existing transmission capacity most completely and the minimization of remaining congestion after the day-ahead market. Therefore the determination of the zonal transfer capacity requires a comprehensible and transparent approach.

We define the zonal transfer capacity as net transfer capacity ($NTC_{z,z'}$) and calculate the $NTC_{z,z'}$ based on the approach described in ENTSO-E (2011). ENTSO-E defines the NTC as the maximum commercial exchange program between two interconnected market zones *z* and *z'*, which is possible without compromising system security and taking into account uncertainties on future network conditions. The $NTC_{z,z'}$, calculated as shown in (4), corresponds to the total transfer capacity ($TTC_{z,z'}$) reduced by a transmission reliability margin (TRM). The $TTC_{z,z'}$ indicates the maximum amount of electric power that can be transferred from one to the other market zone under the security constraints and assuming that all future system conditions are known in advance. The uncertainties involved are then addressed by the TRM that corresponds to the amount of transmission transfer capability necessary to maintain system reliability.

$$NTC_{z,z'} = TTC_{z,z'} - TRM \tag{4}$$

The calculation of the $TTC_{z,z'}$ requires detailed information on future network conditions, generation and load patterns and cross border exchanges. Based on this information the base case exchange ($BCE_{z,z'}$) between the two market zones is computed using the German SCOPF model. The calculation of the initial dispatch and load flows is carried out under the with N-1 security constraints. In order to analyse the impact of RES feed-in on the NTC we already include wind and photovoltaic generation at this stage. (cf. Bucksteeg, Trepper and Weber 2013) To find the maximum additional exchange ($\Delta E_{z,z'}^{max}$) between the two market zones, (conventional and non-intermittent) generation is proportionally increased in the source and decreased in the sink, while loads remain constant, until an N-1 security limit is violated. The $TTC_{z,z'}$ is then given by the sum of $BCE_{z,z'}$ and $\Delta E_{z,z'}^{max}$ as follows in (5):

$$TTC_{z,z'} = BCE_{z,z'} + \Delta E_{z,z'}^{max} \tag{5}$$

The TRM copes with uncertainties of calculated $TTC_{z,z'}$ values arising from the fact that future network conditions are not known perfectly in advance. Uncertainties about the fluctuating RES production and load forecasts, emergency exchanges and load frequency regulation e.g. due to outages can result in unscheduled physical flows between the considered zones. As there is no (European) standard guideline for determining this security margin, the heuristic formula of the German TSOs (cf. Amprion 2012b) as shown in (6) is applied. To illustrate this: in case of nine transmission line circuits connecting two market zones, the calculated $TTC_{z,z'}$ between both zones would have to be reduced by a TRM of 300 MW.

$$TRM = \sqrt{number\ of\ circuits} \cdot 100\ MW \tag{6}$$

According to the described approach, we determine the zonal transfer capacity between Northern Germany (DE_N) and Southern Germany (DE_S) to be about 10,000 MW. A more detailed description of the calculation of zonal transfer capacities can be found in Bucksteeg, Trepper and Weber (2013).

# 6 Results

## 6.1 Security of supply-related indicators

According to the identified SoS indicators, the network situation in Germany will become more critical in 2015 (under the made assumptions). Table 3 compares the identified SoS indicators for 2011 (as far as data is publicly available) and for both scenarios for 2015. Market splitting in Germany yet substantially contributes to system security. Compared to the reference scenario, total congestion and redispatch volumes are both reduced drastically by 72% respectively 59%.

In general a shift in bottlenecks can be observed. Besides already existing bottlenecks (50Hz3/Te5), also new bottlenecks (Amp2/Amp4 and Te5/TrBW1) contribute to high increases in congestion and a nearly doubling of the total redispatch volume compared to 2011. One of the key reasons is the huge increase in RES production – and the resulting transport, including high cross-border loop[15] flows going from the north of Germany over the Czech Republic and Poland to the south of Germany. Besides additional onshore wind capacities also considerable offshore wind capacities are included in 2015. The major part of congestion occurs due to the transport of wind production in the north of Germany to the load centers located in the center and south. Another key reason for congestion (mainly at Amp2/Amp4) is the production of new coal fired plants in Amp2 and Amp3.[16] While the number of the modelled CEH increases within the reference scenario compared to 2011 by 75%, the modelled redispatch amount increases by 92%.

But as for Germany there are only redispatch event hours (REH) publicly available, the direct comparison of the REH for 2011 with the modelled CEH in 2015 has to be done with care. This problem has already been described by Schmitz and Weber (2013), the main difference is that redispatch event hours include also events not related to congestion but e.g. to forecast errors or unplanned plant outages.

However, both SoS indicators suggest that the network situation in 2015 will intensify the TSOs' challenges to secure the grid operation, or in other words: the SoS tends to be more endangered in 2015 compared to 2011.

[15] See (Schavemaker and Beune 2013) for the distinction between loop and transit flows.
[16] Grevenbroich-Neurath BoA 1 and 2 (lignite, 2x 1,050 MW), Walsum (coal, 800 MW) and Datteln 4 (coal, 1,000 MW).

Table 3: Comparison of security of supply indicators for Germany 2015

| **SoS indicator** | *Unit* | **Germany 2011** | **Reference scenario, Germany 2015** | **Market splitting scenario, Germany 2015** |
|---|---|---|---|---|
| **Number of congestion hours** | *Hours* | *not available* | 3,942 | 3,373 |
| **Number of congestion event hours' (CEH)** | *hours* | 5,374[1] | 9,414 | 5,066 |
| **Total congestion amount** | *GWh* | *not available* | 6,350 | 1,795 |
| **Total redispatch amount** | *GWh* | ca. 3,800 | 7,314 | 3,009 |

Notes: [1] number of hours with redispatch measures as per §13.1 EnWG and §13.2 EnWG

Source: Bundesnetzagentur and Bundeskartellamt (2012), TSO websites, own calculations

The implementation of market splitting in Germany has a beneficial effect for SoS in Germany. All four SoS indicators suggest a higher level of SoS than indicated for the scenario without market splitting. While the total number of congestion hours can be reduced by 569 hours (or 14%), the number of CEH decreases by 46% (compared to the reference scenario). The corresponding congestion amount shrinks by 72% through market splitting. Figure 4 shows where congestion and redispatch (related to zones) occurs within both scenarios. As expected, the major reduction in terms of congestion occurs along the zonal border. It is noticeable that the relative level of reduction of congestion, both at the zonal border and within zones, is of comparable height. One might have expected that the relative reduction would be higher at zonal borders, yet there are indirect effects: e.g. if congestion caused by high wind feed-in in the North is already removed by market splitting at the zonal border DE_N/DE_S, this will also reduce the transmission flows within network areas situated more to the South. And consequently also congestion within these areas is lower. But the absolute reduction is of course significantly higher along the zonal border (cf. Figure 4). In addition, Note:
*Interconnection between regions Amp5 and TrBW2
Figure 6 in the Appendix shows in more detail (by region) where congestion occurs. A detailed comparison of congestion event hours by regional border for both scenarios is also included in the Appendix (cf. Table 8).

As shown in Figure 4, the corresponding redispatch amount that is needed to remove congestion can be reduced by 59% through market splitting. The reduction is mainly

achieved within the northern market zone DE_N since congestion occurs in general in direction north to south. Note: *Interconnection between regions Amp5 and TrBW2
Figure 6 in the appendix shows in more detail (by region) where (negative) redispatch is needed to keep up system reliability.

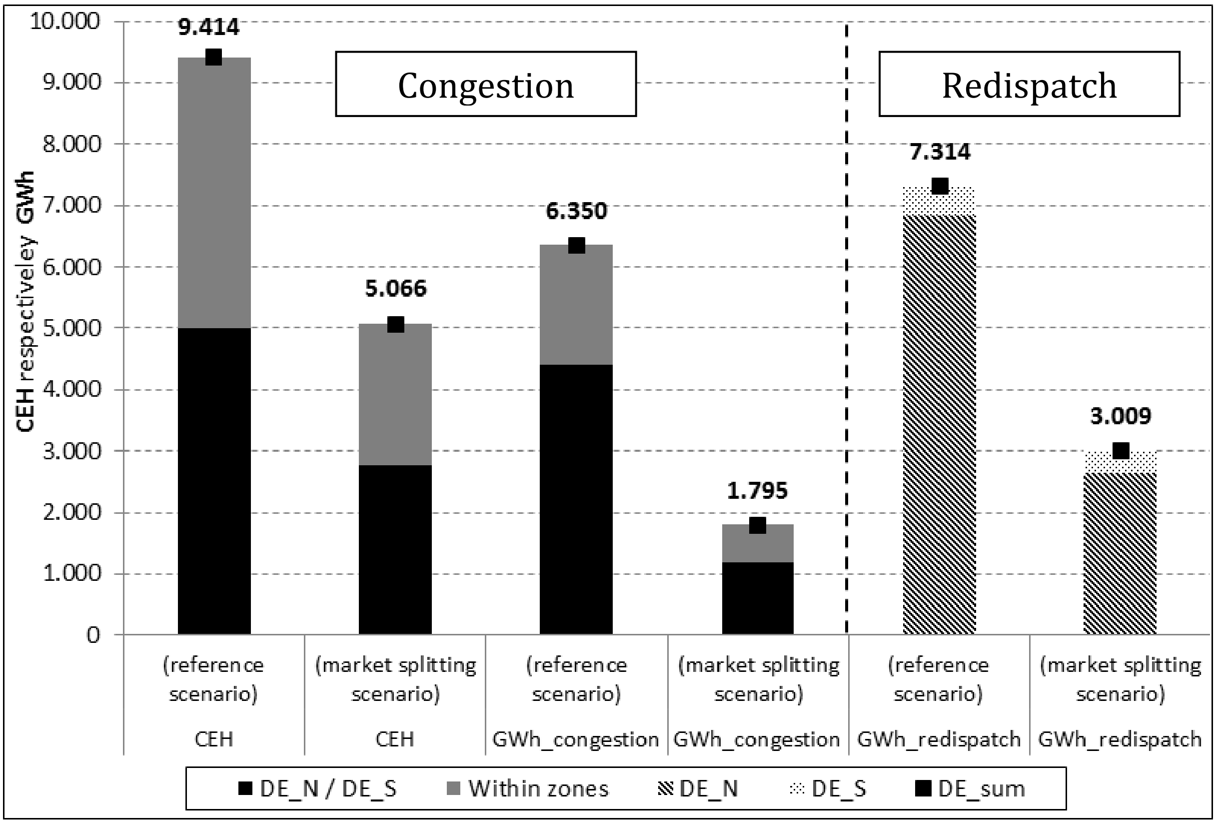


Figure 4: Comparison of congestion (at zonal border and within zones) and redispatch (by market zone) for Germany 2015

It is obvious that congestion within the bidding zones still remains and has to be removed by redispatch as market splitting can only deal with congestion between the bidding zones. But due to transit flows and the unbalanced use of transmission lines along the zonal border, some congestion also remains between the day-ahead bidding zones (ca. 28% compared to the reference scenario 2015, cf. Table 3).

The amount of inter-zonal congestion captured day-ahead, depends strongly on the considered cross-zonal transfer capacity (NTC value). The lower the zonal transfer capacity, the less energy can be traded between the zones day-ahead and the lower is the probability that resulting exchange flows between the zones exceed the physical transmission capacities. The appropriate choice of the zonal transfer capacity has hence a strong influence on the effectiveness of market splitting. Only an appropriate design of the market splitting (zones) assures higher grid stability. But there will still be the need for some redispatch of the system as transmission constraints may be violated by intra-zonal power flows (cf. Hogan 2012).

## 6.2 Economic effects on Germany

Table 4 compares the identified economic indicators for 2011 (as far as data is publicly available) and for both scenarios for 2015. The increase seen in redispatch volumes in 2015 of more than 90% implies also much higher total redispatch costs (+70%). Interestingly, the per-unit redispatch costs I (per $MWh_{redispatch}$) are lower in 2015 compared to 2011. In general, one would expect that the specific redispatch costs would increase if both the total redispatch costs and amount increase. But the relationship between redispatch amount, congestion amount and redispatch costs is not linear due to Kirchhoff's law and different marginal generation costs. Moreover the values for 2011 are derived from actual data and inefficiencies in actual redispatch may have increased the cost.

Table 4: Comparison of economic indicators for Germany 2015

| **Economic indicator** | *Unit* | **Germany 2011** | **Reference scenario, Germany 2015** | **Market splitting scenario, Germany 2015** |
|---|---|---|---|---|
| **Total redispatch costs** | *Mio. EUR* | 130[a] | 221 | 70 |
| **Per-unit redispatch costs I** | *EUR/ $MWh_{redispatch}$* | 34.21 | 30.19 | 23.27 |
| **Per-unit redispatch costs II** | *EUR/ $MWh_{congestion}$* | *not available* | 34.78 | 39.00 |
| **Mean day-ahead price** | | | | |
| **DE** | *EUR/MWh* | 51.58[b] | 47.58 | |
| **DE_N** | *EUR/MWh* | | | 46.48 |
| **DE_S** | *EUR/MWh* | | | 48.78 |
| **Total system costs** | *Mio. EUR* | *not available* | 76,057 | 76,046 |

Notes: [a] includes only costs for redispatch and countertrading
[b] yearly average of volume-weighted EEX Spot prices

Source: Bundesnetzagentur and Bundeskartellamt (2012), www.eex.com, own calculations

The decrease in the average price of 4.0 EUR/MWh obtained in the reference scenario 2015 compared to 2011 is mainly a result of the increased RES production since fuel and $CO_2$ prices are left almost unchanged compared to 2011 (cf. Appendix A.1). Wind and PV production with marginal costs of nearly zero shift the merit order in such a way that conventional power plants with higher marginal costs like old coal power plants are no longer price-setting and are driven out of the market. As a result prices decrease.

In line with the reduction of congestion and redispatch volumes, market splitting induces a strong decrease in total redispatch costs. But while the introduction of market splitting reduces the total redispatch costs by 68% (compared to the reference scenario 2015) the effect on the per-unit redispatch costs is not clear as both types of per-unit redispatch costs develop differently. While the per-unit redispatch costs (I) with regard to the redispatch amount decrease, the per-unit redispatch costs (II) increase when the congestion amount is taken as reference instead. This can be explained by the non-linear relationship between redispatch and congestion amounts. When comparing the relative decrease of congestion and redispatch amounts, a much higher decrease of the congestion amount is observed.

Market splitting affects prices only in those hours in which congestion occurs. This occurs in 2,736 hours in 2015 and leads to a difference of 2.30 EUR/MWh in yearly average prices between both market zones. Day-ahead prices in the south of Germany increase due to the fact that higher-cost units located in DE_S have to be dispatched in order to meet the local demand as day-ahead transfer capacity and therefore the import of wind energy from the north of Germany is limited. In parallel, day-ahead prices in the north of Germany decrease due to the limited export capacities to the south. According to the described price effect, the consumers in DE_N could benefit from market splitting while the producer rents decrease. Conversely, the producers in DE_S would benefit from increasing prices induced by market splitting while the consumer rents would decrease.

In total, the introduction of market splitting in Germany leads to a negligible reduction of total system costs of only 11 Mio EUR in Europe[17]. This is probably an underestimation of the actual cost savings since a cost-efficient redispatch under perfect foresight is assumed. Yet it is nevertheless an indication that short-term inflexibilities are not a strong driver for redispatch cost.

The duration curves of the hourly power prices for the German market and the market zones are shown in Figure 5. While the mean price difference is 2.30 EUR/MWh (cf. Table 4), the price differences go up to 3.65 EUR/MWh. Interesting with regard to the current discussion surrounding the issue of the need for a capacity mechanism in Germany is the improvement in operating profits for peaking units. As expected the

[17] Costs for wind curtailment are not considered.

prices in southern Germany are higher during peak times, what is beneficially for peak power plants. A first rough quantification of the effect is obtained by comparing the operating profits per kW for a simple clean-spark spread option, i.e. a gas-fired CCGT plant with neither operating restrictions nor start-up costs. At variable costs of 50 EUR/MWh, the operating profit is 20.20 EUR/kW in the scenario without market splitting. This value increases to 24.50 EUR/kW in DE_S in the case of market splitting, i.e. an improvement by 21 %. With slightly higher variable costs of 55 EUR/MWh, the relative difference even increases to 38 %, with 10.40 EUR/kW operating profits in DE_S with market splitting and 7.60 EUR/kW without. This is still far from covering the capital costs, yet it may at least cover annual fix costs for staff, insurance etc. and thus avoid the shutdown of existing capacities even without a capacity payment. The improvement in profitability is even more pronounced in absolute terms yet the relative improvement is below 10 %.

A detailed analysis of investment incentives through market splitting is yet not the primary focus of this study and should therefore be addressed in future research.[18]

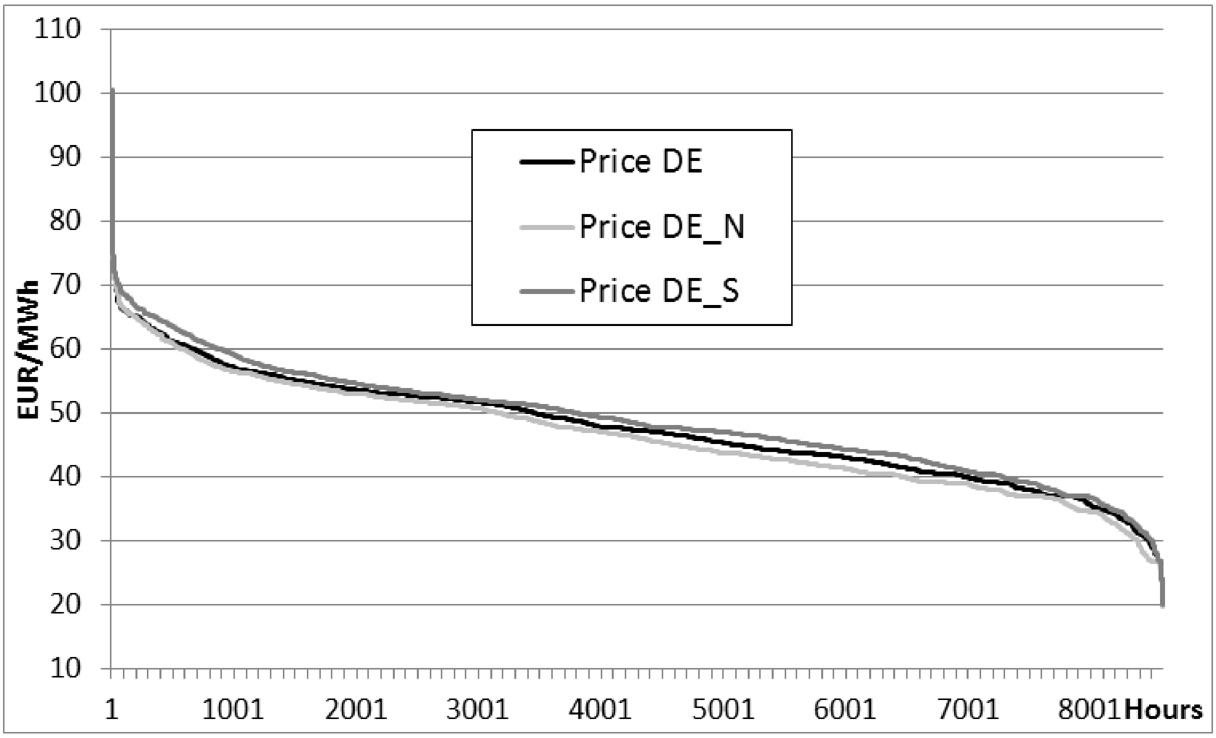


Figure 5: Duration curves of power prices for Germany 2015

The main benefits of market splitting for Germany rather seen in a significant increase of security of supply (cf. section 6.1) and one may argue that, compared to the current

[18] (Harvey and Hogan 2000) already discuss several implications of zonal pricing with regard to the setting of incentives for transmission investments.

German uniform market price, market splitting could set weak but potentially better investment signals for generation capacities.

As the European grid is highly meshed, changes in market design in one electricity market affect also prices levels and the corresponding cross-border flows within the total ENTSO-E grid. The price effects of the introduction of market splitting in Germany on relevant European countries is shown in the Appendix A.4.

# 7 Conclusion

Our analysis indicates a much more critical network situation in Germany in 2015 than in 2011. In general, a shift in bottlenecks can be observed. New bottlenecks (Amp2/Amp4 and Te5/TrBW1) as well as already existing ones (Thüringer Waldleitung 50Hz3/Te5) lead almost to a doubling of redispatch in 2015 compared to 2011. Four main drivers can be identified:

- Increasing RES production (far away from load centers)
- Resulting export and import flows
- Grid extension not keeping pace with RES expansion
- Nuclear phase-out.

Table 5: Brief overview of key results 2015 with focus on Germany

| *Perspective* | *Situation in Germany in 2015*<br><br>*(Reference scenario 2015)* | *Effects of market splitting for Germany in 2015*<br>*(Market splitting scenario 2015)* |
|---|---|---|
| **Security of supply** | • High increases in total congestion and redispatch volumes in Germany (+92% compared to 2011)<br>• Main bottlenecks: Amp2/Amp4, 50Hz3/Te5, Te5/TrBW1<br>• High loop flows from north of Germany over PL and CZ to south of Germany<br>• Main drivers: Increasing RES, corresponding export and import flows, grid extension not keeping pace with RES expansion<br>• All four SoS indicators suggest a more critical network situation in Germany | • Significant reducing effect on total congestion (-72%) and redispatch (-59%) volumes<br>• All four SoS indicators suggest a higher level of SoS than in the scenario without market splitting<br>• But some congestion still remains<br>• Beneficial effect depends strongly on:<br>(1) Appropriate design of market zones<br>(2) Appropriate determination of zonal transfer capacity |
| **Economic** | • Much higher redispatch costs than 2011 in Germany (+ 91 Mio EUR)<br>• But per-unit (specific) redispatch costs decrease<br>• Decrease of yearly average price due | • 151 Mio EUR decrease of redispatch costs in Germany<br>• Effect of market splitting on the per-unit redispatch costs is not clear |

| | | |
|---|---|---|
| | to high RES production | • Decrease of (average) price in DE_N and higher (average) price in DE_S<br>• Total welfare effect in Europe is negligible (11 Mio EUR)[19] |

Together with the high increase in the total redispatch volume, the total redispatch cost also increase by 70% in 2015 compared to 2011.

The security-of-supply indicators selected here make clear that the implementation of market splitting in Germany substantially contributes to secure grid operation. Compared to the reference scenario, total congestion and redispatch volumes are both reduced significantly by 73% respectively 59%. Yet some congestion still remains in the model.[20] This is due to loop flows and the unbalanced use of transmission capacities along the zonal border. Compared to the reference scenario 2015 total redispatch costs are reduced by 68%. The limited transfer capacity between both German market zones results in lower prices in the north and higher prices in the south on average. According to these price effects one could derive that the consumers in the north of Germany (DE_N) would gain along with the producers in the south (DE_S). However, the total welfare effect induced by market splitting in Germany calculated as difference of the total system costs is negligible (decrease of total European system costs by 11 Mio. EUR).

As already stated above, the major contribution of market splitting is a significant increase in system security. But the beneficial effects of market splitting depend strongly on a "good design". This includes in particular (1) the appropriate design of the day-ahead market zones and (2) the adequate determination of the zonal transfer capacity. The zonal borders should run along the main bottlenecks to catch main congestions already on the day-ahead market. Changing flow patterns however require also regular checks and adaptations of the market zones. Concerning the determination of the zonal transfer capacity, a trade-off between market liquidity and the effectiveness of congestion management arises. If the transfer capacity is set too high, this will lower the effectiveness of market splitting as the amount of remaining redispatch after day-ahead market closure is high. If the zonal transfer capacity is determined too low, market liquidity will be reduced and the entire available transport capacity will frequently not be fully used. However, there will still be the need for some redispatch of the system as

[19] Without consideration of changes in wind curtailment.
[20] However, a complete avoidance of redispatch would yet not be feasible due to e.g. plant outages and forecast errors. Furthermore there will still be the need for some redispatch of the system as transmission constraints may be violated by intra-zonal power flows (cf. Hogan 2012).

transmission constraints may be violated by not reflected intra-zonal power flows. Especially with regard to congestion, there is no way to a perfect zonal market design as it is not possible to determine aggregated market zones and consider intra-zonal impacts on the transmission grid ex ante Hogan (2012). Only locational marginal prices fully reflect all constraints of the transmission system.

Obviously a differentiated choice between market splitting and grid extension is needed to mitigate security of supply-related risks. And also TSO measures like flow-controlling devices have to be taken into account. Market splitting cannot be expected to be the ‚one and only solution'. But our model calculations show that market splitting can be an (interim) solution to manage upcoming congestion in Germany in times when grid expansion has not yet been concluded (construction delays) and that market splitting can also serve as an alternative to grid extension within less congested areas.

## Acknowledgement

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# Appendix

## A.1 Indices, parameters and decision variables of WILMAR Joint Market Model

| **Indices and Sets** | **Description** |
|---|---|
| *r, r', r'', r** | Index of regions |
| *s, S* | Index and Set of scenarios |
| *t, T* | Index and Set of time steps within a scenario tree |
| $V$ | Set of connecting lines between regions |
| $AC$ | Alternating current |
| $DC$ | Direct current |

| **Parameters** | **Description** |
|---|---|
| $L_{r,r\prime,t}^{TRANS,DAY-AHEAD,MAX}$ | Maximum transfer capacity of tie lines from region *r* to *r'* on the day-ahead market. |
| $L_{r,r\prime,t}^{TRANS,INTRADAY,MAX}$ | Maximum transmission capacity of tie lines from region *r* to *r'* on the intraday market. |
| $B^{TRANS,INTRADAY\_YES}$ | MIP-related parameter: Transmission scheduled on both the intraday and day-ahead market<br>if set to 1 transmission capacity is scheduled on both the intraday and the day-ahead market,<br>if set to 0 transmission capacity is available for the day-ahead market and not for the intraday market ('copperplate'). After the day-ahead market has been cleared the transmission between regions cannot be changed. |
| $B^{TRANS,NONSP\_YES}$ | MIP-related parameter: Transmission of non-spinning secondary reserve<br>if set to 1 the exchange of positive secondary reserve between regions is possible,<br>if set to 0 positive secondary reserve has to be provided within each region and exchange is not possible. |
| $ptdf_{r,r\prime,r^*,r^{**},t}$ | Power transfer distribution factor of the tie lines *r*, *r'* for the real power transaction between regions *r** (source) and *r*** (sink) at time step *t*. For a fixed sink it can be written $ptdf_{r,r\prime,r^*,t}$ |

| **Decision Variables** | **Description** |
|---|---|
| $P_{r,r\prime,t}^{TRANS,DAY-AHEAD}$ | Planned transmission (on all transmission lines) from region r to region r' when bidding on the day-ahead market at time step t |
| $P_{r,r\prime,t}^{TRANS,DAY-AHEAD,AC}$ | Planned transmission on AC transmission lines from region r to region r' when bidding on the day-ahead market at time step t |
| $P_{r,r\prime,t}^{TRANS,DAY-AHEAD,DC}$ | Planned transmission on DC transmission lines from region r to region r' when bidding on the day-ahead market at time step t |
| $P_{r,r',s,t}^{TRANS,INTRADAY,AC,+}$, $P_{r,r',s,t}^{TRANS,INTRADAY,AC,-}$ | Contribution to up/ down regulation after day-ahead market closure (= redispatch measures in case of perfect forecast) in region r' by increased/ decreased transmission of power on AC transmission lines from region r to region r' in scenario s at time step t |
| $P_{r,r',s,t}^{TRANS,INTRADAY,DC,+}$, $P_{r,r',s,t}^{TRANS,INTRADAY,DC,-}$ | Contribution to up/ down regulation after day-ahead market closure (= redispatch measures in case of perfect forecast) in region r' by increased/ decreased transmission of power on DC transmission lines from region r to region r' in scenario s at time step t |
| $P_{r,r',s,t}^{TRANS,NONSP,ANC,AC,+}$, $P_{r,r\prime,s,t}^{TRANS,NONSP,ANC,AC,-}$ | Reservation of up/ down regulation at non-spinning secondary reserve market in region r' by increased/ decreased transmission of power on AC transmission lines from region r to region r' in scenario s at time step t. |
| $P_{r,r',s,t}^{TRANS,NONSP,ANC,DC,+}$, $P_{r,r\prime,s,t}^{TRANS,NONSP,ANC,DC,-}$ | Reservation of up/ down regulation at non-spinning secondary reserve market in region r' by increased/ decreased transmission of power on DC transmission lines from region r to region r' in scenario s at time step t. |

## A.2 Detailed data description

In addition to the brief data description in section 5.1, the input data used is described in the following in more detail. There are some parameters which are constant in all scenarios and which are taken from the reference year 2008. These are in particular: wind and solar profiles, electricity respectively heat demand profiles, electricity respectively heat demand level, water reservoir levels, water inflows and plant availabilities.

- **Electricity demand**

It is assumed that the European economy has recovered from the financial crisis in 2015 and that therefore the electricity demand reaches in 2015 the level seen in 2008. The regional distribution of the total demand levels (as provided by ENTSO-E 2008) has been done in relation to the distribution of inhabitants per ZIP code.

- **Renewables: Wind and solar production**

As already mentioned within section 5.1 wind and solar production are modelled as exogenous production and are region-specific. The regional distribution of solar and wind production for 2015 in Germany is done proportionally to the distribution of the installed capacities 2008. The distribution of the offshore production is proportional to the installed capacities of the planned projects: 88% North Sea and 12% Baltic Sea. The assumed wind and solar production is shown in Table 2.

- **Conventional power plants**

While the total installed capacity is considered in the European dispatch model (LP JMM Europe), the vertical load retained in the German dispatch model (MIP JMM DE) has only to be met by those power plants which are directly connected to the high-voltage transmission grid or which are relevant for redispatch. Table 6 shows the considered energy mix in the German dispatch model MIP JMM DE.

Table 6: Energy mix 2015 for Germany as considered in MIP JMM DE[21]

| ***Technology*** | ***Installed capacity in GW (MIP JMM DE)*** | ***Technology*** | ***Installed capacity in GW (MIP JMM DE)*** |
|---|---|---|---|
| Nuclear | 12.2 | Run-of-river | 0.05 |
| Lignite | 19.5 | Annual storage plant | 0.9 |
| Coal | 26.8 | Pumping storage plant | 7.3 |
| Biomass | 0.6 | Photovoltaic | 53.8 |
| Gas | 11.4 | Wind onshore | 35.4 |
| Oil | 1.1 | Wind offshore | 4.7 |

[21] Only power plants with direct interconnection to the high-voltage-transmission grid or with high relevance for redispatch.

- **Transmission Network**

For Germany, the main grid expansion projects considered as finished in 2015 are the transmission lines Görris/Krümmel (50Hz1/50Hz2), Lauchstädt/Vieselbach (intra-region 50Hz3) and Hamburg/Nord-Dollern (Te1/Te2) and the phase shifter Diele. NTC values determining the day-ahead trading capabilities between European countries e.g. between Germany and Austria are taken from ENTSO-E (cf. ENTSO-E 2010). As already described within section 3, NTC and PTDF used for load flow approximation within Germany are derived from the nodal DC German load flow model as described in section 3.2.

- **Fuel- and $CO_2$-prices**

Fuel prices are represented as sum of a general fuel price (cf. Table 7), wherever possible derived from market future prices for 2015 and a region-specific transportation cost component.

Table 7: General fuel and $CO_2$ price assumptions 2015

| Commodity | Price in 2015 |
|---|---|
| Coal | 12.94 EUR/MWh |
| Natural Gas | 27.14 EUR/MWh |
| Fueloil | 39.13 EUR/MWh |
| Lightoil | 56.25 EUR/MWh |
| Lignite | 4.53 EUR/MWh |
| Nuclear | 2.35 EUR/MWh |
| $CO_2$ | 9.27 EUR/t $CO_2$ |

## A.3 Further analysis concerning congestion and redispatch for Germany

Table 8 gives a detailed comparison of congestion event hours by regional border for both scenarios in 2015.

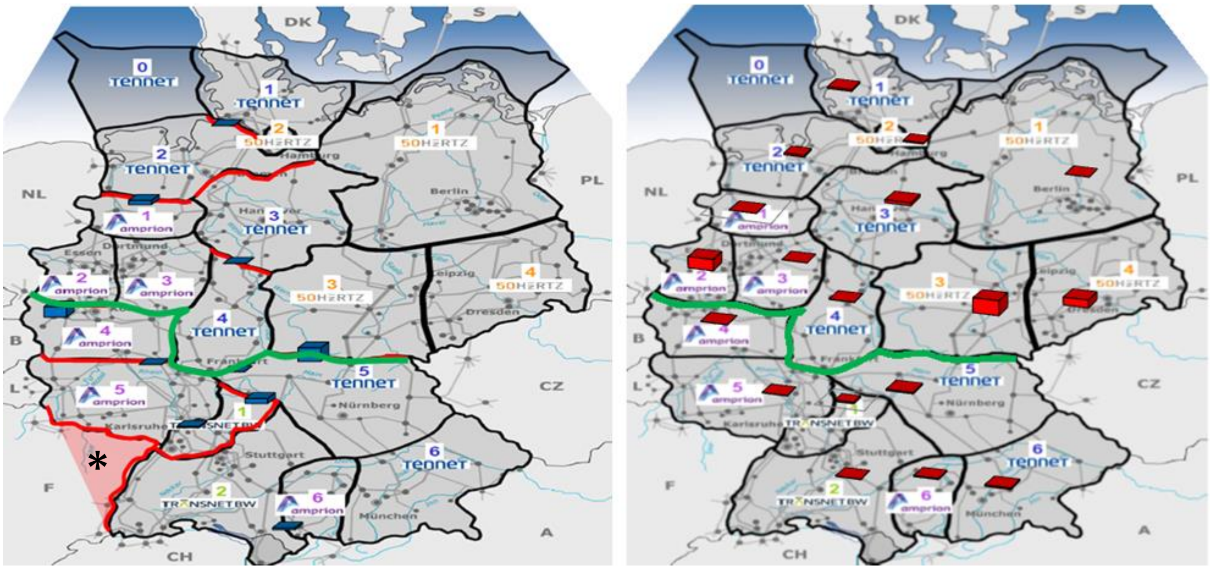
Table 8: Comparison of congestion event hours by regional border for Germany

| Regional Border | CEH<br>Reference scenario | CEH<br>Market splitting scenario |
|---|---|---|
| **R_AMP1_R_AMP2** | 8 | 8 |
| **R_AMP1_R_AMP3** | 19 | 19 |
| **R_AMP2_R_AMP4** | 2,569 | 1,122 |
| **R_AMP3_R_AMP4** | 9 | 0 |
| **R_AMP4_R_AMP5** | 887 | 28 |

| | | |
|---|---|---|
| **R_EnBW1_R_AMP5** | 201 | 200 |
| **R_EnBW2_R_AMP5** | 67 | 5 |
| **R_EnBW2_R_AMP6** | 243 | 271 |
| **R_TP2_R_AMP1** | 955 | 666 |
| **R_TP3_R_50Hz1** | 4 | 3 |
| **R_TP3_R_AMP1** | 77 | 47 |
| **R_TP3_R_TP4** | 199 | 35 |
| **R_TP4_R_AMP4** | 31 | 23 |
| **R_TP4_R_TP5** | 69 | 0 |
| **R_TP5_R_50Hz3** | 2,322 | 1,614 |
| **R_TP5_R_EnBW1** | 1,754 | 1,025 |
| **Total CEH** | **9,414** | **5,066** |

To enable a better understanding of the effects of market splitting on redispatch, Note: *Interconnection between regions Amp5 and TrBW2

Figure 6 shows in which regions negative redispatch is still needed to keep up system reliability in 2015.



Note: *Interconnection between regions Amp5 and TrBW2

Figure 6: Congestion amount for the top 10 regional borders (left) and negative redispatch amount by region (right) for Germany (market splitting scenario)

## A.4 Economic Effects on neighbouring countries

As the European grid is highly meshed, changes in market design in one electricity market affect also prices levels and the corresponding cross-border flows within the total ENTSO-E grid.

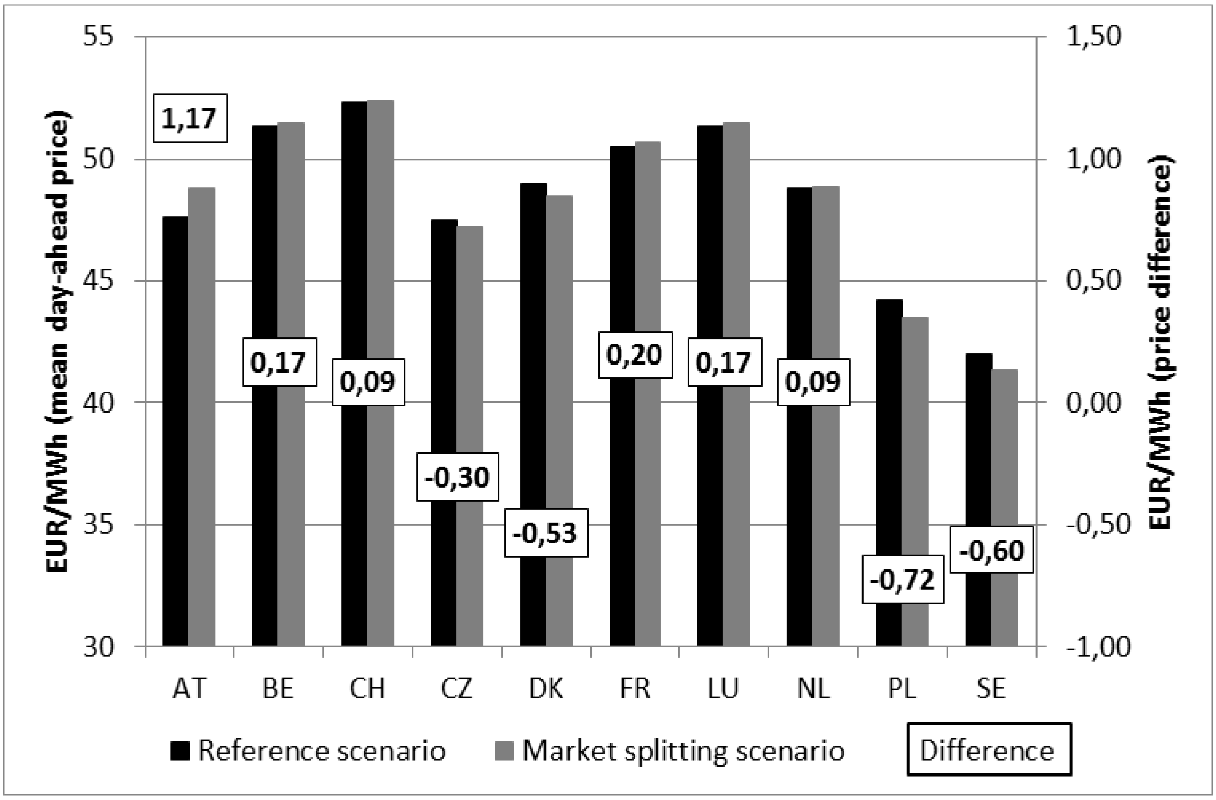



Figure 7: Comparison of yearly average day-ahead prices of selected European countries (2015)

Figure 7 shows the price effects of market splitting in Germany on the yearly average day-ahead prices of neighbouring countries for both scenarios in 2015. The price effects induced by market splitting on Poland, Sweden, France and Austria seem to be very clear. As Poland and Sweden are directly connected to DE_N the decreasing price effect of market splitting in Germany within DE_N has also a decreasing effect on the average price levels of Poland and Sweden. The same applies conversely for France and Austria due to their interconnections with DE_S. However, the interpretation of price effects on the Netherlands and on the Czech Republic is difficult as those markets are connected to both market zones in Germany. Under the model assumptions made, market splitting in Germany leads in 2015 to a lower price level in CZ on yearly average. At a first glance, the Dutch prices seem to be only slightly affected by market splitting in Germany as the yearly average price level in NL does not change very much. But this impression has to be revised when considering the much higher absolute price difference of 1.06 EUR/MWh on average (cf. Table 9).

Table 9: Effect of market splitting in Germany on day-ahead prices of selected European countries for 2015 (in EUR/MWh)

| Country | Average day-ahead price, reference scenario 2015 | Average day-ahead price, market splitting scenario 2015 | Mean price difference | Mean absolute price difference |
|---|---|---|---|---|
| **AT** | 47.61 | 48.78 | **1.17** | **1.38** |
| **BE** | 51.32 | 51.49 | **0.17** | **0.42** |
| **CH** | 52.33 | 52.42 | **0.09** | **0.30** |
| **CZ** | 47.51 | 47.21 | **-0.31** | **0.97** |
| **DK** | 48.98 | 48.45 | **-0.53** | **0.76** |
| **FR** | 50.46 | 50.66 | **0.20** | **0.42** |
| **LU** | 51.33 | 51.50 | **0.17** | **0.42** |
| **NL** | 48.77 | 48.86 | **0.09** | **1.06** |
| **PL** | 44.23 | 43.51 | **-0.72** | **0.99** |
| **SE** | 41.97 | 41.37 | **-0.59** | **0.67** |

According to the described price effects, the producers in France and Austria would especially gain along with the consumers in Sweden and Poland.