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Impacts of Res-Generation and Demand Pattern on Net Transfer Capacity: Implications for Effectiveness of Market Splitting in Germany

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Chair for Management Science and Energy Economics
University of Duisburg-Essen

EWL Working Paper No. [02/2014]

**IMPACTS OF RES-GENERATION AND DEMAND PATTERN ON
NET TRANSFER CAPACITY: IMPLICATIONS FOR EFFECTIVE-
NESS OF MARKET SPLITTING IN GERMANY**

by

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and

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01.05.2014

IMPACTS OF RES-GENERATION AND DEMAND PATTERN ON NET TRANSFER CAPACITY: IMPLICATIONS FOR EFFECTIVENESS OF MARKET SPLITTING IN GERMANY

by Michael Bucksteeg, Katrin Trepper, Christoph Weber

Abstract

For the further development of an integrated European electricity market, congestion management mechanisms are one of the major market design issues. Against the background of increasing generation from RES and resulting congestions, an efficient management of network congestions is gaining importance especially in Germany. Introducing nodal pricing as the first best mechanism is not considered to be realistic for Germany in the nearer future. Yet the splitting of the German electricity market into several market zones will also improve congestion management. A key issue in the so-called market splitting is the determination of the net transfer capacity (NTC) between the market zones as it determines the effectiveness of market splitting as congestion management mechanism. We therefore develop an integrated approach to incorporate the effects of renewables feed-in, load pattern and cross border flows on NTCs. We conclude that the NTCs strongly depend on RES infeed and that this effect has to be considered when modelling alternative congestion management mechanisms like market splitting.

Keywords : net transfer capacity, congestion management, market splitting

JEL-Classification : Q40, Q47, Q49

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1 Introduction

The energy markets and systems in Europe and worldwide experience more and more power generation far from the load centres and intermittent feed-in from renewable energy sources (RES). Especially in Germany this leads to serious differences in the geographical distribution of power generation and load flows between the hours of the year, as already today more than 80% of installed wind onshore capacity is located in the northern regions (cf. AMPRION ET AL. 2013). Given the nuclear phase-out and assuming that further delays in transmission grid expansion will occur in the nearby future (cf. BUNDESNETZAGENTUR AND BUNDESKARTELLAMT 2012, BUNDESKARTELLAMT 2012a), the extension of offshore wind energy particularly in the North Sea will amplify Germany's North-South congestion problem. The German market design is characterised by uniform prices. Congestion is removed by redispatch. Against this background, the four German TSOs will be challenged to ensure the system security requirements and alternative congestion management mechanisms are becoming more important.

The implementation of nodal pricing as first best congestion management alternative (cf. HOGAN 1992) in the nearer future is not considered to be realistic by the regulating authorities due to the need for a Europe-wide ISO (cf. e.g. OGGIONI AND SMEERS 2013, OPTIMATE 2011). Yet, a considerable improvement of the efficiency of congestion management can also be achieved by splitting the German electricity market into several market zones (cf. TREPPER ET AL. 2014). A key issue in the so-called market splitting is the determination of the net transfer capacity (NTC) between the market zones as its level affects the effectiveness of market splitting. This paper aims to analyse the specific effects of RES feed-in, demand pattern and the corresponding international cross border exchange on NTCs, PTDFs and load flows. Of particular interest are thereby the implications for a fictitious market splitting in Germany. To achieve this we develop an adequate methodology for determining the transfer capacity between market zones (with respect to the German power system). Yet within an integrated approach we first model the European flows in an upstream linear power plant dispatch model and then incorporate those import and export flows in a nodal security constrained optimal power flow (SCOPF) model for Germany. We determine NTCs related to load and RES infeed pattern as well as cross border flows and compare those values with a fixed NTC for a representative system state. Thereby Germany is split along the major congestion modelled for 2015 (cf. TREPPER ET AL. 2014) into two market zones.

The remaining paper is organized as follows. First we give a short review of the relevant academic literature in section 2. In section 3 we describe our methodology and the data

used. Beside the description of the WILMAR Joint Market Model and the German load flow model we also characterise our approach for the determination of the transfer capacity between market zones. Section 4 points out the impacts of RES feed-in, demand pattern and the corresponding exchange balance on load flows, power flow sensitivities and transfer capacities. Furthermore we discuss the implications of our results for the effectiveness of market splitting in section 5. Section 6 concludes.

2 Literature survey

Several studies have already addressed the impacts of wind feed-in on transfer capacity, but ignored the complexity and influences caused by the interconnection of national electricity markets and transmission grids. LUNA ET AL. (2011) analyse the impacts of wind feed-in on transfer capacities using a 24-bus system. Their focus is on the analysis of the intermittent characteristics of wind generation and the geographical distribution of wind power plants. They find that an increase of wind generation units with loads remaining constant may cause limitations of the transfer capacity.

Also TONG ET AL. (2010) identify the impact of wind generation on transfer capacity as initial point for the determination of transmission capacities. They develop a new approach for calculating transfer capacities and show numerical results for a 30- and 118-bus system. The authors state that depending on the locational distribution and feed-in pattern of wind plants, the transfer capacities change heavily.

GANG ET AL. (2013) develop a sensitivity method based on optimal power flow and incorporate uncertainties arising from wind generation using Latin hypercube sampling and a clustering algorithm. They find a strong correlation between intermittent wind generation and the volatility of the transfer capacity.¹

The publications known to us have in common the use of fictitious and small test systems with 24, 30 or 118 buses. Furthermore the installed wind capacity is lower than 1 GW. One main issue of this paper is therefore to analyse if the same holds for large and complex power systems like the German one with probably more than 40 GW installed wind capacity in 2015.

BALDICK (2003) and BALDICK ET AL. (2005) analyse variations of Power Transfer Distribution Factors (PTDFs) in a large scale power system. PTDFs are an input factor for computing NTCs. They find that PTDFs for three principal interconnections of the North

¹ In literature most authors refer to the available transfer capability (ATC) when analyzing transfer capacities. The ATC is part of the NTC and results by deducting the already allocated capacity (AAC, e.g. long term contracts between market participants) from the NTC. However in most publications the AAC is assumed to be zero. Thus the calculated ATC corresponds to the NTC.

American power system vary when reaching power system limits. However they focus on the impact of loading and not of RES-generation on PTDFs.

RIOUS ET AL. (2008) study the impact of German wind generation on the transfer capacity between Belgium and France. The model used is based on ZHOU AND BIALEK (2005). Going one step further they incorporate wind generation into the calculation of the base case and show that increasing wind generation leads to an increase of the transfer capacity between Belgium and France. Furthermore they point out the importance of the geographical distribution of wind power plants for an accurate calculation of transfer capacity.

NEUHOFF ET AL. (2013) analyse several design options for the European power market and assess the benefits of nodal pricing versus zonal pricing (market coupling). The initial point of their analysis is the integration of intermittent RES feed-in. However, when modelling zonal pricing they neglect that with varying wind feed-in the transfer capacities would not remain constant over time.

WEIGT ET AL. (2010) compare nodal, zonal and uniform pricing and study the benefits of HVDC² extension for integrating large scale wind generation in Germany. The establishment of zonal pricing in Germany is based on six bidding zones proposed by DENA (2005). They conclude that the impact of zonal pricing on welfare is limited. Thereby they ignore that an appropriate delimitation of market zones should follow the main bottlenecks which may change with increasing installed wind capacities towards 2015. Furthermore, they do not consider the impact of intermittent wind generation on transfer capacities when modelling zonal pricing.

BURSTEDDE (2013) analyses implications for introducing zonal pricing in Europe. Thereby the author proposes a clustering approach and focuses on the delimitation of bidding zones based on locational marginal prices of 72 basic regions for Austria, Switzerland, Germany, the Netherlands, Belgium and France. However, she does not discuss the determination of the transfer capacities between the built bidding zones when analysing the impacts of zonal pricing on congestion and redispatch.

The present paper adds to the current literature by filling the mentioned gaps and assesses the impacts of RES feed-in and demand pattern on the NTC for a fictitious yet appropriate market splitting scenario for Germany. Subsequently we draw important implications for the effectiveness of zonal pricing.

² High-voltage direct current

3 Methodology and data

3.1 Modelling approach

In order to determine the impacts of RES-generation and demand pattern on load flows and the NTC, we link two power system models via a clustering approach. The modelling approach, the relevant results and the input and output relations between the steps are shown in **Fehler! Verweisquelle konnte nicht gefunden werden.** and described in the following.

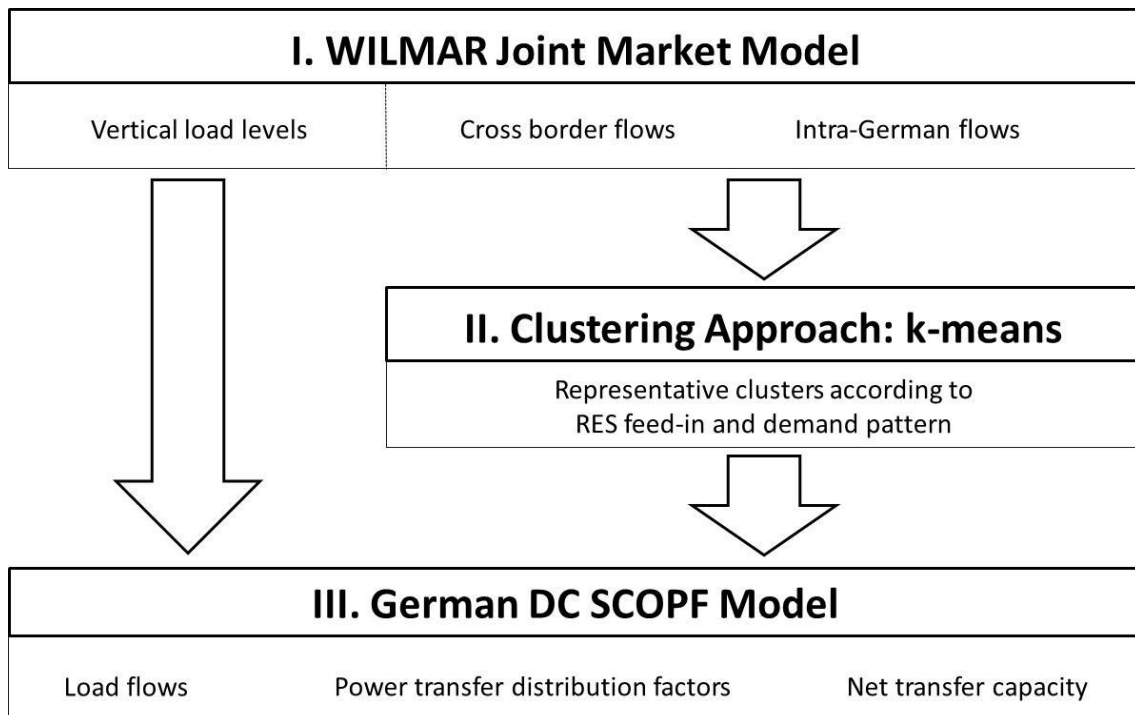


Figure 1: Modelling approach and relevant results

- I. Since the integration of European power markets progressed in recent years, we model the dispatch on a European but aggregated level for all 8,760 hours in 2015 in a first step. The **WILMAR Joint Market Model** provides (among others) results on hourly imports and exports to/from Germany, intra-German flows and vertical load levels for the German transmission grid. Also occurring congestion in Germany is modelled within this step.
- II. Running the German DC SCOPF Model (step III) for a full year (8,760 hours) implies extremely high and thus hardly manageable computational efforts. Instead we identify in step II representative scenarios by using the k-means clustering algorithm. As RES-generation and demand pattern affect the cross border exchange

and intra-German flows, these results from the WILMAR Joint Market Model (step I) are clustered using the **k-means algorithm**.

- III. In the third step we calculate load flows and PTDFs for each specific scenario (cluster) in the **German DC SCOPF Model**. In addition we calculate NTCs for transactions between German market zones and analyse the impacts of RES-generation and demand pattern within this step. When introducing market splitting, the zonal border should run along the main bottlenecks to achieve high effectiveness. Based on the main congestion identified within the upstream WILMAR Joint Market Model in step I, Germany is split into several market zones.

A more detailed description of the models and the clustering approach is given in the following sections.

3.2 WILMAR Joint Market Model – Description

The *WILMAR Joint Market Model* was developed within the EU-projects WILMAR and SUPWIND³ and can be described as a stochastic scheduling tool to analyse the impact of the fluctuating RES feed-in in energy markets. The objective function minimizes the overall variable system costs over the optimization period, covering fuel, CO₂, start-up and further variable costs. Several technical constraints e.g. startup time, minimum up and down times, ramping rates, minimum and maximum generation, reserve targets and transmission capacities are covered. Beside electricity also heat demand has to be met in 8,760 hours of the year. The planning horizon of the *WILMAR Joint Market Model* is up to 36 hours with hourly optimization and rolling planning.⁴ More detailed information about the model including all equations can be found in TREPPER ET AL. (2014), WEBER ET AL. (2009), TUOHY ET AL. (2009), BARTH ET AL. (2006) and MEIBOM ET AL. (2006).

The model covers the ENTSO-E grid apart from the Baltic States. The European countries except for Germany and Denmark are mapped as 29 aggregated country nodes. Germany is modelled in more detail and is represented by 21 nodes according to the regional electricity transport model of the German TSOs (cf. AMPRION ET AL. 2013). Thereby wind offshore generation is subsumed under three regions, where two offshore regions in the North Sea are connected to the onshore regions TenneT1 and TenneT2 and one region in the Baltic Sea is connected to 50Hertz1.

³ 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.

⁴ Thereby the amount of power sold or bought from the day-ahead market is determined in the planning period 1. In the subsequent replanning periods, these variables are fixed to the values found in planning period 1, such that the obligations on the day-ahead market are considered when the intraday optimization takes place. (cf. WEBER ET AL. 2009).

To achieve manageable computation times, some simplifications have been made within the used version *LP JMM Europe* of the WILMAR Joint Market Model. Most important are the following:⁵

- The generation units are grouped to power plant classes and the technical restrictions are approximated in a linear way (cf. WEBER ET AL. 2009).
- Originally, rolling planning is done every 3 hours in the WILMAR project. But to limit computation times we adapt the rolling to 12 hours.
- Further no load and wind forecast errors or unplanned plant outages are considered within this study (“perfect forecast”), as we do not focus on reserve requirements but on cross border flows.

Consequently no modelling of intraday-trading and reserve capacities for balancing forecast errors is needed. Therefore we can reduce the optimization problem to two decision problems. First a day-ahead market for physical delivery of electricity is cleared corresponding to EPEX-based trading, whereby total electricity demand and RES feed-in are given exogenously. Afterwards the transmission constraints are taken into account and the day-ahead committed power plants are, if necessary, re-dispatched to remove occurring congestion.

One part of the relevant output of the *WILMAR Joint Market Model* are the modelled European cross border flows which are used for modelling imports and exports in the *German DC SCOPF Model*. Furthermore the WILMAR Joint Market Model obtains intra-German flows for the interconnections of the German regional electricity transport model. These flows are used as an indicator for the utilization of the German transmission grid and for the delimitation of the zonal border. Moreover hourly vertical load levels are calculated.

3.3 Clustering approach – k-means algorithm

The clustering approach links both models, the WILMAR Joint Market Model and the German DC SCOPF Model, and allows us to determine the impacts of characteristic situations with regard to RES feed-in and demand pattern on load flows, PTDFs and NTCs.

Cluster analysis is a multivariate analytical method for classifying a heterogeneous set of objects to homogeneous subsets respectively groups or clusters (cf. HARTIGAN 1975). This grouping should be done in such a way that the observations within a cluster are as similar as possible, but clusters are as dissimilar as possible. In literature, hierarchical and partitioning methods are distinguished (cf. GAN ET AL. 2007). While hierarchical clustering methods start with one cluster for each observation and end with an optimal number of well-separated clusters, partitioning methods reallocate observations start-

⁵ TREPPER ET AL. (2014) give a more detailed description of the differences between the existing different variants of the model WILMAR JMM.

ing from an initial partitioning or cluster centres. We decided to apply a partitioning method and to iterate until cluster costs are minimized.

The k-means algorithm (cf. HARTIGAN 1975 and HARTIGAN AND WONG 1979) reallocates objects to clusters according to the chosen measure of distance. The sum of distances from each group member to its cluster centroid is minimized over all clusters. Previously the number of clusters has to be decided.

For the classification of hours, the cross border flows and intra-German flows obtained from the *WILMAR Joint Market Model* are used as cluster criteria. The transmission flows are an adequate indicator for potential grid congestions. They are also closely linked to changes in pattern and level of RES-generation and demand. ZUGNO ET AL. (2012) perform a statistical analysis of the impact of wind power generation on cross border flows. They find that variation of wind generation in Germany causes changes in the pattern of cross border flows and induce loop and transit flows.⁶

The k-means algorithm involves an iterative process, as follows. The algorithm differentiates the H data points x_h into k disjoint subsets respectively clusters S_n by using the least-squares method. h indicates the considered hours and x_h is given by the vector of the hourly transmission flows on the regarded tie lines. The clustering function as described in BISHOP (1995) is given by:

$$J = \sum_{n=1}^k \sum_{x_h \in S_n} \|x_h - \mu_n\|^2 \rightarrow Min! \quad (1)$$

where $h = \{1, \dots, H_n\}$

J as the sum of the squared differences between the data points x_h which belong to the cluster S_n and the centroid μ_n of the data points in this cluster has to be minimized. μ_n is the geometric center (centroid) of the data points in cluster S_n and is given by:

$$\mu_n = \frac{1}{H_n} \sum_{h \in S_n} x_h \quad (2)$$

The algorithm begins by assigning an initial cluster centroid position. We performed therefore a preliminary clustering phase on a random 10% subsample of all objects. This preliminary clustering phase itself selected two objects at random.⁷ After computing the centroids as means each data point is allocated to the nearest cluster centroid respec-

⁶ For the distinction between loop and transit flows see SCHAVEMAKER AND BEUNE (2013).

⁷ PEÑA ET AL. (1999) compare empirically four classical initialization methods for k-means with respect to their robustness and effectiveness. The authors show that the random and Kaufman's approach (KAUFMAN AND ROUSSEUW 1990) outperform the two other considered methods.

tively mean. Next the means are recomputed. This iterative process is repeated as long as the recalculation of cluster centroids leads to a reallocation of data points to clusters. In other words: the k-means algorithm reallocates the hourly cross border and intra-German flows to clusters until the sum of distances cannot be decreased. In this case, clusters are as compact and well-separated as possible (cf. BISHOP 1995).

It is well-known that the k-means algorithm is sensitive to the selected starting point as shown by MILLIGAN (1980). The resulting clusters may depend on the initial choice of starting point for calculation of cluster centroids. In general, the algorithm does therefore not achieve a global minimum of J (cf. SELIM 1984). But k-means is quick, especially when large data amounts have to be clustered and is also easy to implement. It is one of the most used iterative partitioning clustering algorithms and with the initialization method implemented here, the results should be rather robust (cf. PEÑA ET AL. 1999).

Every cluster S_n is then represented by one scenario, corresponding to the hour which has the smallest centroid distance. This scenario may notably be characterised by its RES feed-in and demand pattern. The resulting effects on line loadings, PTDFs and NTCs are then assessed using the *German DC SCOPF Model*.

3.4 German DC SCOPF model

Load flows for the German transmission grid, PTDFs for the interconnections of the regional electricity transport model and NTCs for the fictitious zonal border are calculated after running a DC security constrained optimal power flow model (DC SCOPF model) in PowerWorld Simulator (cf. POWERWORLD 2013).

The formulation of the OPF problem incorporating contingencies and security constraints first appears in literature in 1974 (cf. ALSAC AND STOTT 1974). ALSAC AND STOTT extend an approach developed by DOMMEL AND TINNEY (1968) and apply an OPF model for solving the optimal base case at the beginning. As a second step, insecurities arising from outages are detected and the outage security is monitored using an AC load flow method. In a further step, they continue the OPF solution incorporating the constraints found in the second step until the insecurities are removed. STOTT ET AL. (2009) point out that using a linear model (for determining the insecurities) has advantages in terms of computation times and efficiency especially when analysing huge and complex power systems. The calculation of NTCs is based on several power system sensitivities (PTDFs, LODFs and OTDFs, cf. next section). OVERBYE ET AL. (2004) and BALDICK ET AL. (2005) compare sensitivities calculated with AC and DC power flow models and conclude that DC sensitivities are very close to sensitivities calculated with AC models. Even when incorporating outages sensitivities remain very close. We therefore neglect reactive power and voltage considerations and accept small inaccuracies. We consequently decide to

use a DC model. The corresponding optimization problem is well defined and the main characteristics of the DC SCOPF model may e.g. be found in ALSAC AND STOTT 1974.

The German *DC SCOPF model* includes a much more detailed geographical representation than the *WILMAR Joint Market Model*. It covers the total 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, superimposed offshore and on-shore wind generation and the locational vertical load levels (total load minus subordinated RES feed-in and subordinated conventional generation). **Fehler! Verweisquelle konnte nicht gefunden werden.** shows the graphical representation of the SCOPF model.

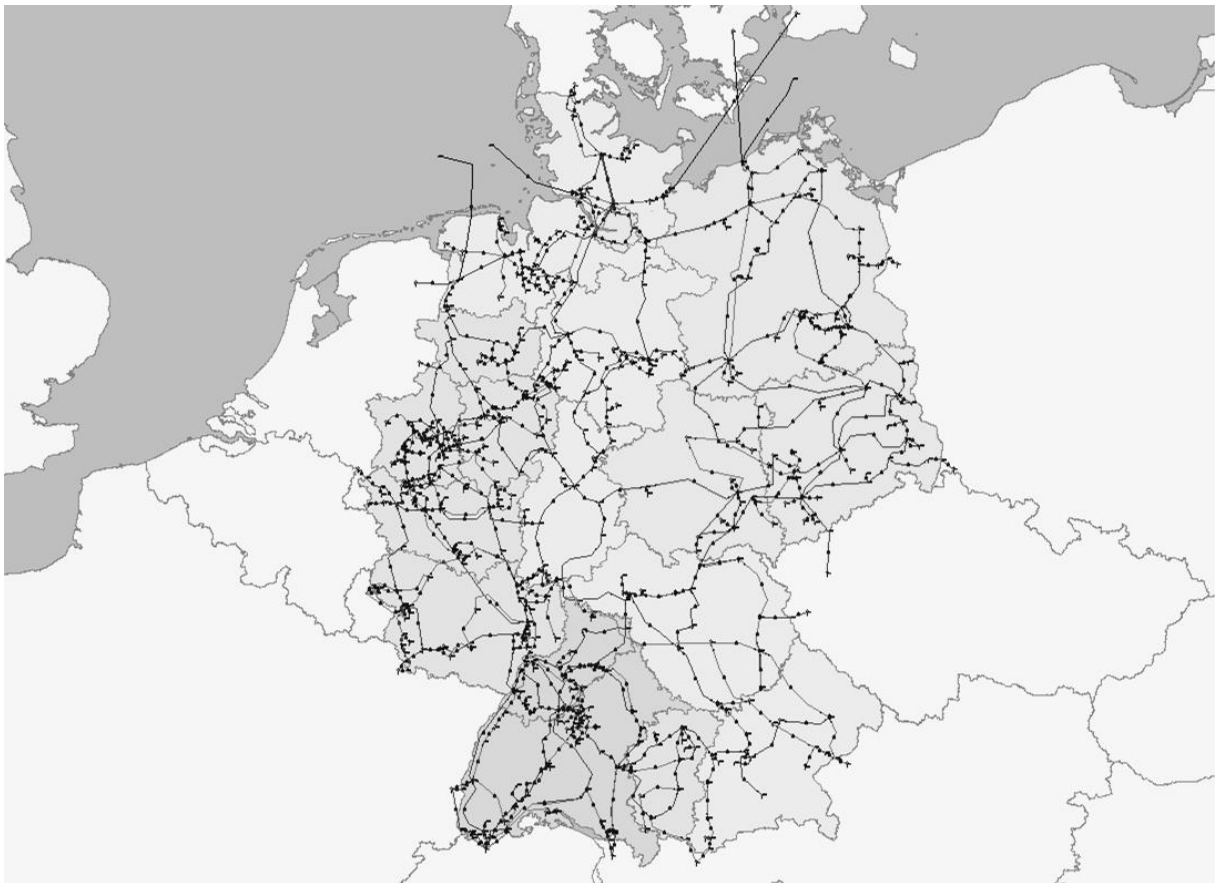


Figure 2: DC SCOPF model representation of the German transmission grid in 2015

The objective function in the *German DC SCOPF model* is the minimization of the overall costs of generation with subject to generation capacities, maximum line flow constraints and violations that would occur during contingencies. Generation and plant operating limits are modelled unit-wise and the generation costs of each unit are approximated by a linear cost function. To cover part load efficiency we linearize the costs in-between minimum and maximum capacity. The generation costs include fuel, CO₂ and variable

operation and maintenance costs (cf. section 3.6). As the *SCOPF model* is not inter-temporal we ignore time-dependent costs like start-up and ramping costs. The maximum line flow constraints are given by the thermal limits of the branches. The set of contingencies includes possible outages of each circuit and unit. Vertical load has to be met, while imports and exports are taken as modelled in the *WILMAR Joint Market Model*. Wind production is allowed to be curtailed in case of congestion to meet the maximum line flow constraints.

The surrounding countries are represented by country nodes that are connected to the German grid via cross border lines. The interconnections are modelled considering their length and voltage level. The cross border capacities are assumed to be unlimited as the cross border flows are exogenous and based on the hourly exchange computed with the *WILMAR Joint Market Model*. According to the ENTSO-E-network map, the model includes 18 interconnections to consider the import and export flows from/to Denmark, Sweden, Poland, Czech Republic, Austria, Switzerland, France, Luxembourg and the Netherlands.

3.5 Determination of NTCs

The calculation of *NTCs* is performed within the *German DC SCOPF Model*. While procedures for capacity assessment provided by ENTSO-E offer a harmonised base to calculate *NTCs*, in power system and energy market modelling most studies ignore the need for subsequent *NTC* calculations to incorporate changes in load and especially RES-generation pattern (cf. ENTSO-E 2011, ENTSO-E 2012a, NEUHOFF ET AL. 2013). Furthermore the effects of line and unit outages should be included to meet the N-1 criteria.

Based on the approach of ENTSO-E (2011) we define *NTC* as the maximum commercial exchange program between two interconnected market zones z and z' without compromising system security and taking into account uncertainties on future network conditions. As shown in (3), the $NTC_{zz'}$ is part of the total transfer capacity ($TTC_{zz'}$) which is reduced by a transmission reliability margin (*TRM*). The $TTC_{zz'}$ indicates the maximum amount of electric power that can be transferred from one market zone to another without violating security limits and assuming that all future system conditions are known with certainty in advance. The uncertainties involved are then addressed by the *TRM*, which specifies the amount of transmission transfer capability necessary to maintain system reliability.

$$NTC_{zz'} = TTC_{zz'} - TRM \tag{3}$$

$$\text{Where: } TTC_{zz'} = BCE_{zz'} + \Delta E_{zz'}^{max}$$

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

The TRM copes with uncertainties of calculated $TTCs$ arising from the uncertainties about future network conditions. Unanticipated events like forecast errors of RES-feed-in and load patterns or 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 we apply the heuristic formula of the German TSOs (cf. AMPRION 2012) as also shown in (3). To illustrate this: in case of nine transmission line circuits connecting two market zones, the calculated $TTC_{zz'}$ between both zones would have to be reduced by a TRM of 300 MW.

The calculation of the $TTC_{zz'}$ is complex and requires detailed information on future network conditions, generation and load patterns and cross border flows.⁸ Based on this information, we start with computing the base case exchange (BCE) between the two market zones. The calculation of the initial dispatch and load flows is carried out as to be compatible with N-1 security standards (SCOPF). In order to analyse the impact of RES feed-in on $NTC_{zz'}$ we already include wind and photovoltaic generation at this stage.⁹

For a considered transaction zz' between two market zones (or nodes) z and z' , the BCE is given by the sum of the base case power flows P_{ij}^0 on all transmission lines connecting zones z and z' :

$$BCE_{zz'} = \sum P_{ij}^0, ij \in \text{connecting transmission lines} \quad (4)$$

To find the maximum additional exchange $\Delta E_{zz'}^{max}$ between the two market zones a sensitivity analysis is performed. First we calculate power transfer distribution factors (PTDF) for the considered transaction zz' as in (5), where z is the source and z' the sink:

$$PTDF_{ij,z} = \frac{\Delta P_{ij}}{\Delta T_{zz'}} \quad (5)$$

ΔP_{ij} is thereby the change in real power flow on line ij for transaction zz' obtained by a change of the transaction volume $T_{zz'}$.

To incorporate the effects of a line outage we then compute line outage distribution factors (LODF) based on a set of possible contingencies as indicated by SAUER ET AL. (2001) and given in (6):

⁸ For a detailed description see SAUER ET AL. (2001) and GHAWGHAWE AND THAKRE (2006).

⁹ Following ENTSO-E, the BCE relates to the best forecast for exchanges between two zones at the considered time period. Due to the priority feed-in of RES in Germany and the impact on power flows the forecast for wind and photovoltaic generation is included in the BCE. In the absence of long-term transmission contracts, the calculated transfer capacities correspond also to the available transfer capabilities (ATC).

$$LODF_{ab,ij,z} = \frac{PTDF_{ab,z}^{outage} - PTDF_{ab,z}^{pre_outage}}{PTDF_{ij,z}^{pre_outage}} \quad (6)$$

In case of a line outage the real power flow P_{ij}^{outage} on line ij can be calculated (as shown in 7) based on the real power flows before the outage $P_{ij}^{pre_outage}$ and $P_{ab}^{pre_outage}$, where the real power flow on line ab before the outage has to be absorbed by the transmission lines that are still online. The share of absorption for line ij is given by $LODF_{ab,ij,z}$.

$$P_{ij}^{outage} = P_{ij}^{pre_outage} + LODF_{ab,ij,z} \cdot P_{ab}^{pre_outage} \quad (7)$$

While P_{ij}^{outage} indicates the absolute value of the real power flow on line ij after the outage for calculating the maximum additional exchange $\Delta E_{zz'}^{max}$ we have to define the relative percentage of the transfer that will flow on line ij after the outage as described in (8):

$$OTDF_{ij,z} = PTDF_{ij,z} + LODF_{ab,ij,z} \cdot PTDF_{ab,z} \quad (8)$$

By incorporating all possible outages and choosing the minimum of additional exchange capacity no overloading in case of contingencies is allowed and system security is guaranteed. The maximum additional exchange $\Delta E_{zz'}^{max}$ is finally stated as:

$$\Delta E_{zz'}^{max} = \min \left(\frac{P_{ij}^{max} - P_{ij}^{outage}}{OTDF_{ij,z}}, ij \in \text{connecting transmission lines} \right) \quad (9)$$

3.6 Data

An overview of further relevant assumptions and input data used is given in the following.

As reference year the year 2008 is chosen due to the full availability of data and the already performed backtesting for the validation of the *WILMAR Joint Market Model* and the input data done within several projects. There are some parameters which are constant and taken from the reference year. 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. The current German market design related to RES is retained. That means especially that RES feed-in has (unlim-

ited) priority and wind curtailment is allowed only for purposes of system security in both models. In general, the development of RES within all further European countries is based on the national renewable action plans.

The input data needed for both models can be categorized into the following three categories:

- Representation of the transmission network
- Generation: capacities and variable costs
- Electricity demand

Representation of the transmission network

Due to the complexity and in order to keep calculation times manageable we simplify the system representation for the *WILMAR Joint Market Model*. The European transmission network is represented by 50 (country) nodes, whereby Germany is mapped with 21 nodes. The transfer capacities determining the day-ahead trading capabilities within the *WILMAR Joint Market Model* between European countries are taken from ENTSO-E (2010) and are assumed to be unchanged in 2015.

The transmission lines and nodes of the *German DC SCOPF Model* are obtained manually from the ENTSO-E Grid Map (cf. ENTSO-E 2012) and are validated based on further publicly available grid maps (cf. VDE, OPENSTREETMAP, OPENGRIDDATA). For creating the data base we use ArcGIS.¹⁰

The electrical parameters of the transmission lines are estimated from the lengths, voltage levels and typical impedance values for German overhead lines. The thermal limits and impedance values are obtained from KIESSLING ET AL. (2003). The lengths are computed with the program ArcGIS. As the status of circuit breakers is not publicly available all circuit breakers are assumed to be closed and therefore all lines are in operation. Furthermore there is no information on transformer capacity publicly available. We therefore assume that transformers are not congested and the capacities are sufficiently high (3,150 MVA). Typical impedance values are taken from MACHOWSKI ET AL. (1997). Since we only consider DC power flows we ignore resistance and shunt admittances (cf. section 3.4).

Given the currently known delays in grid expansion, the timely completion of all projects proposed under the DENA studies respectively the EnLAG projects (cf. DEUTSCHE ENERGIE-AGENTUR 2005, DEUTSCHE ENERGIE-AGENTUR 2010, BUNDESNETZAGENTUR 2012b) has been reviewed carefully for both models and in particular for the German transmission grid. The main German grid expansion projects considered as completed in 2015 are the transmission lines Görris/Krümmel (50Hertz1/50Hertz2), Lauchstädt/Vieselbach (in-

¹⁰ ArcGIS is a platform for designing and managing solutions through the application of geographic knowledge. For more details see www.esri.com.

tra-region 50Hertz3), Bertikow/Neuenhagen (intra-region 50Hertz1) and Hamburg/Nord-Dollern (TenneT1/TenneT2) and the phase shifter Diele.

Generation: Capacities and variable costs

The capacities of conventional power plants in Europe including commissioning and de-commissioning date are taken from the EWL data base, which is continuously updated based on publications and press reports. For Germany, the power plant park 2015 is considered especially with regard to the power plant list published by BUNDESNETZAGENTUR (2012). Regarding fuel, technology and construction year, we summarise all conventional power plants into power plant classes for usage in the *WILMAR Joint Market Model*. Within the *German DC SCOPF Model* instead all German power plants connected to the high-voltage transmission grid are modelled unit-wise. The assignment of power plants to grid nodes as needed within the *German DC SCOPF Model* is done (manually) via Google maps and using ArcGIS.

While the *WILMAR Joint Market Model* considers the total installed generation capacity in Europe, the vertical load retained in the *German DC SCOPF Model* has only to be met by those power plants which are directly connected to the German high-voltage transmission grid. Table 1 shows the considered installed capacities in both models.

Table 1: Energy mix 2015 for Germany as considered in both models

Installed capacity in GW					
Technology	WILMAR	DC	Technology	WILMAR	DC
	JMM	SCOPF		JMM	SCOPF
Nuclear	12.2	12.2	Pumping storage	8.8	7.3
Lignite	19.5	19.5	Hydro reservoir	1.5	0.9
Coal	31.5	26.8	Run-of-river	3.8	0.05
Biomass	3.4	0.6	Photovoltaic	53.8	0
Gas	25.7	11.4	Wind onshore	35.4	0
Oil	2.7	1.1	Wind offshore	4.7	4.7

Fuel prices are represented as sum of a general fuel price (cf. Table 2), derived from market future prices for 2015 wherever possible, and a region-specific transportation cost component. We also include variable operation & maintenance costs taken from the EWL database, based on publications and expert knowledge.

Table 2: General fuel and CO₂ 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

Wind and solar production are modelled exogenously. In the *WILMAR Joint Market Model*, the RES-generation is mapped to the regions. Except of Germany, wind production amounts for all European countries are taken from the EWEA medium term forecast for 2015. The German wind and solar production are assumed to be as forecasted by AMPRI-ON ET AL. (2012) and shown in Table 3. The regional distribution of solar and wind production for 2015 in Germany is done proportionally to the distribution of the installed capacities in 2008. The distribution of the offshore production is proportional to the installed capacities of the planned projects: 88% North Sea and 12% Baltic Sea.

Table 3: RES production 2015 in Germany (in TWh)

RES	2015
Wind onshore	61.39
Wind offshore	19.02
Photovoltaic	49.52
Total	129.93

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.

In the *WILMAR Joint Market Model* 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. In the *German DC SCOPF Model* the regional vertical load levels (obtained from the *WILMAR Joint Market Model*) are also assigned to the buses in relation to the distribution of inhabitants per ZIP code. To calculate vertical load levels the total demand levels are adjusted by conventional generation and RES-infeed connected to the subordinated grid levels. For the geographical assignment of vertical load levels we use ArcGIS.

4 Results and discussions

4.1 Zonal delimitation and clustering results

When introducing market splitting, the zonal borders should run along the main bottlenecks (cf. TREPPER ET AL 2014). For the identification of the bottlenecks, we analyse the hourly flows and occurring congestions on tie lines between the regions of the regional electricity transport model of the German TSOs computed with the *WILMAR Joint Market Model*. We find the main bottlenecks in 2015 to be expected between Amp2-Amp4, 50Hertz3-TenneT5 and TenneT5-TrBW1 (cf. **Fehler! Verweisquelle konnte nicht gefunden werden.**). The main drivers identified are high wind generation in the northern part of Germany and comparable high load levels in the southern regions of Germany. While the transmission lines between 50Hertz3 and TenneT5 were mostly congested already during the last years, the bottleneck between the regions Amp2 and Amp4 is caused by the generation of new coal power plants combined with high RES feed-in. Consequently, we decide to split the German power market into two market zones in order to capture the major congestion. As we find the bottleneck between TenneT5 and TrBW1 is already relieved by the described market splitting we decided against a further splitting into three market zones. The zonal delimitation is shown in **Fehler! Verweisquelle konnte nicht gefunden werden..**

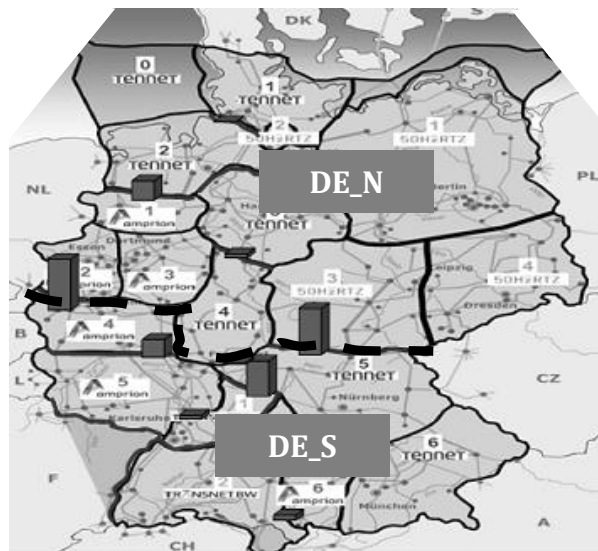


Figure 3: Congestions in a single German power market and delimitation of two price zones

This delimitation is also in line with previous studies conducted by CONSENTEC AND FRONTIER ECONOMICS (2011) and BREUER ET AL. (2013). In the following DE_N is referred to as the northern market zone and DE_S summarizes the southern regions.

The cluster analysis of the modelled cross border and intra-German flows (as modelled within the *WILMAR Joint Market Model*) allows us to determine the impacts of characteristic situations with regard to RES feed-in and demand pattern on load flows, PTDFs and NTCs (for the described zonal delimitation). Each of these situations respectively clusters represents one hour for which the German load flow situation is then calculated in more detail utilizing the *German DC SCOPF Model*. The cluster analysis of the cross border and the intra German flows (both obtained from the *WILMAR Joint Market Model*) provides twelve clusters or stated in other words twelve representative situations. Table 4 gives an overview of the resulting clusters which are characterised by the corresponding levels of vertical load , exchange balance, RES infeed and the calculated NTC. These values correspond to the hour characterised by the smallest centroid distance to the cluster centroid.

Table 4: Vertical load level + exchange balance, RES infeed and NTCs in MW for resulting clusters¹¹

Cluster	Cluster elements	Vertical Load + Exchange			ΔE	BCE	TTC	TRM	NTC
		Balance	Wind*	PV*					
12	464	31,595	6,047	0	3,396	7,321	10,717	-480	10,237
7	694	39,213	3,297	30,761	13,852	-1,391	12,461	-480	11,981
11	941	44,502	659	0	7,044	2,287	9,331	-480	8,851
3	878	45,322	5,568	0	5,963	4,573	10,536	-480	10,056
2	645	46,253	893	0	8,157	2,262	10,419	-480	9,939
4	614	47,356	13,140	16,624	8,401	-423	7,978	-480	7,498
6	779	49,121	4,552	0	4,992	4,517	9,509	-480	9,029
9	872	51,146	5,425	0	5,676	5,021	10,697	-480	10,217
8	681	59,592	9,000	34	5,716	4,030	9,746	-480	9,266
1	670	61,190	13,636	0	4,416	3,481	7,897	-480	7,417
5	746	74,179	20,607	0	4,403	5,706	10,108	-480	9,629
10	752	81,196	31,747	0	7,530	4,923	12,453	-480	11,973

* Total wind and photovoltaic infeed: in the DC SCOPF Model part of the vertical load levels (total demand – conventional generation and RES-infeed connected to the subordinated grid levels)

The correlation analysis of the considered factors (vertical load + exchange balance, wind and pv) and computed NTCs provides some important insights: In practice the German TSOs apply a so-called “C function” for the determination of bilateral NTCs for South-West cross border interconnections (cf. TENNET 2012 or AMPRION 2012). This function mainly depends on the wind generation in Germany. In contrast our results do not indicate such a linear correlation between high wind infeed and NTC .

¹¹ For more detailed results see Appendix.

For the following reasons we cannot identify a clear correlation between the considered factors and the calculated NTCs (which are relevant to the market participants). First, demand and RES generation are not geographically uniform. Second, the German respectively European power system is characterised to be highly complex. While other studies consider small test systems and the infeed of all wind generation at only one singular bus (cf. e.g. LUNA ET AL. 2011), we tried to model demand and generation pattern more realistic and under consideration of import and export flows. In addition, we observe an unbalanced utilization of transmission lines among the zonal border and bi-directional load flows, what can both induce effects that cancel each other.

A more detailed analysis especially of the components of the NTC (BCE and ΔE) and the at first glance illogical effect of an increasing NTC with increasing wind infeed is given in section 4.3. As more than 80% of onshore wind power plants are located in the northern regions and wind feed-in is strongly correlated with resulting load flows and congestions for our further analysis we first focus on four wind scenarios. To isolate the effects of wind generation we select four typical clusters (or scenarios) according to wind generation and demand (clusters 11, 8, 5 and 10). The impacts of wind generation and demand in Germany on load flows, PTDFs and on NTCs are described in the following. Furthermore typical clusters according to photovoltaic generation are analysed (clusters 1, 4 and 7). Finally the impacts on the effectiveness of a specific market splitting scenario for Germany are discussed.

4.2 Impacts on load flows

Figure 4 compares the resulting load flows for two clusters with minimum and maximum wind feed-in. Three key points can be identified: first, a high wind feed-in causes a North-South flow with additional imports from Denmark and Sweden and exports to the southern countries (FR, CH, AT). Second, in hours with high wind feed-in loop flows (DE-NL and DE-CZ) can be observed. Third, partly opposite load flows from generation to load centres in hours with low wind feed-in may occur.

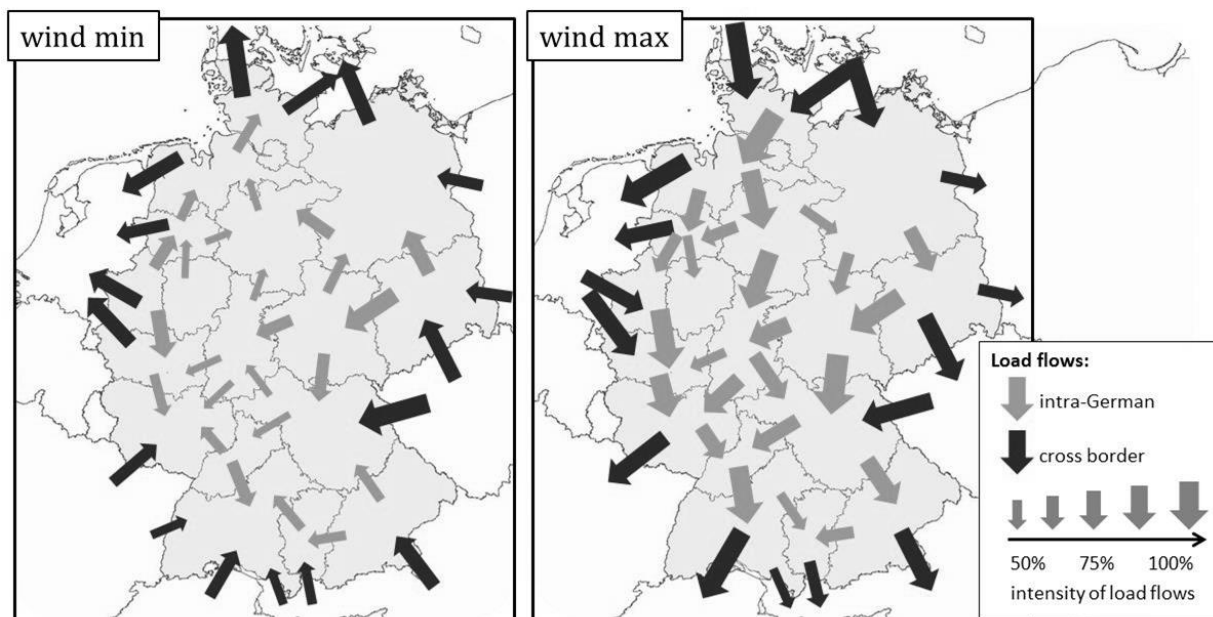


Figure 4: Impact of wind generation and load in Germany on intra-German and cross border flows

4.3 Impacts on PTDFs

As discussed in section 3.5, PTDFs are an input factor for the calculation of NTCs respectively the component ΔE^{max} . Several authors already addressed variations of PTDFs. While OVERBYE ET AL. (2004) address differences between AC and DC PTDFs, BALDICK ET AL. (2005) analyse the impact of load variations on PTDFs. They find that under normal conditions the variations in PTDFs are limited. In Germany, intermittent wind in-feed is concentrated in the northern regions while a higher share of photovoltaic generation is located in the southern regions. As most RES-capacity is connected to subordinated grid levels, fluctuations of RES-generation cause variations of vertical load levels. In the following we therefore focus on the impact of intermittent RES-generation on PTDFs and load flows. For this analysis we calculate PTDFs for the tie lines of the regional electricity transport model of the German TSOs.

Figure 5 depicts the frequency distribution of the deviations of DC PTDFs for the considered wind scenarios. Comparing the high and low wind scenarios, one would expect the PTDFs to differ strongly as high wind feed-in changes the generation pattern for Germany and results in heavily utilized transmission lines. But more than 80% of the deviations of PTDFs are within the interval -0.5 to +0.5 percentage points. A main reason for this observation is that the PTDFs only consider a change in the distribution of flows on the tie lines between the regions and not on intra-regional transmission lines. The highest deviations (2.89 or -1.93 percentage points) can be observed on tie lines in the northern regions as higher wind feed-in results in a change of power plant dispatch and an unbalanced utilization of the affected transmission lines (especially TenneT1, TenneT2 and 50Hertz2).

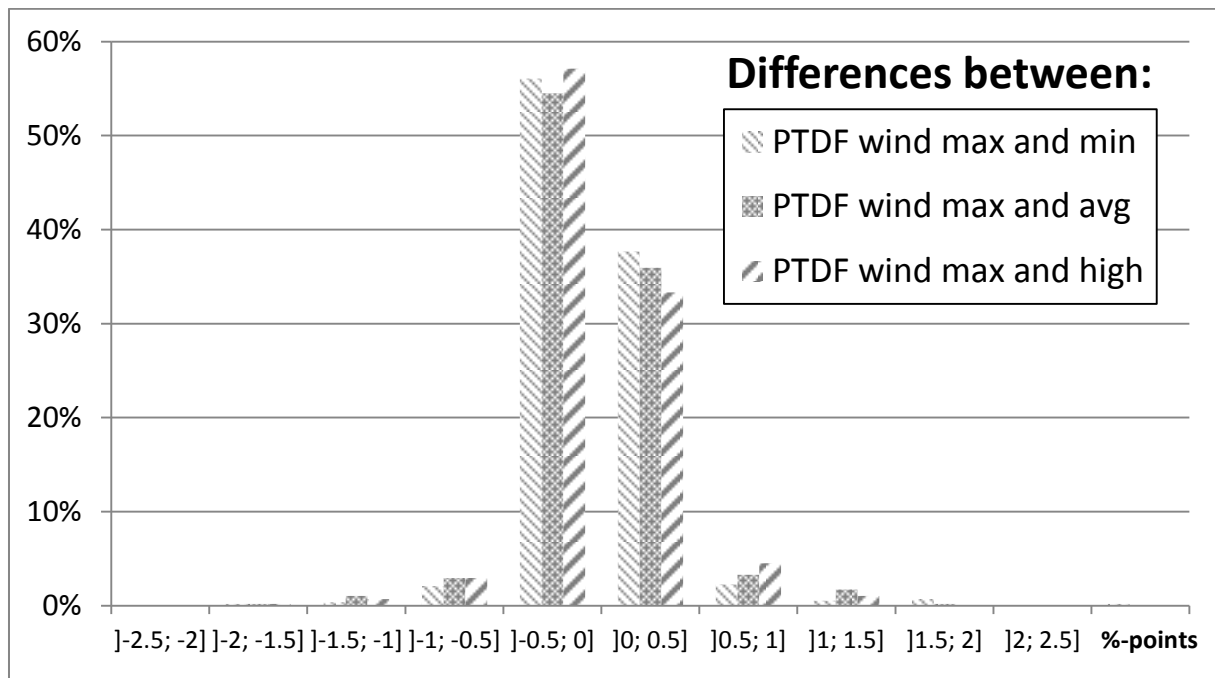


Figure 5: Frequency of deviations of DC PTDFs for the wind scenarios

In Figure 6, we compare the PTDFs of the scenarios with minimum and maximum wind generation. The PTDFs for both scenarios are very closely related. The same holds true for a comparison of different photovoltaic feed-in levels. The results are not shown in this paper as the deviations of PTDFs are more driven by wind generation. This finding suggests that for the purposes of energy market modelling, the utilization of only one PTDF-matrix does not cause major errors. However this only applies for an aggregated representation of the transmission grid.

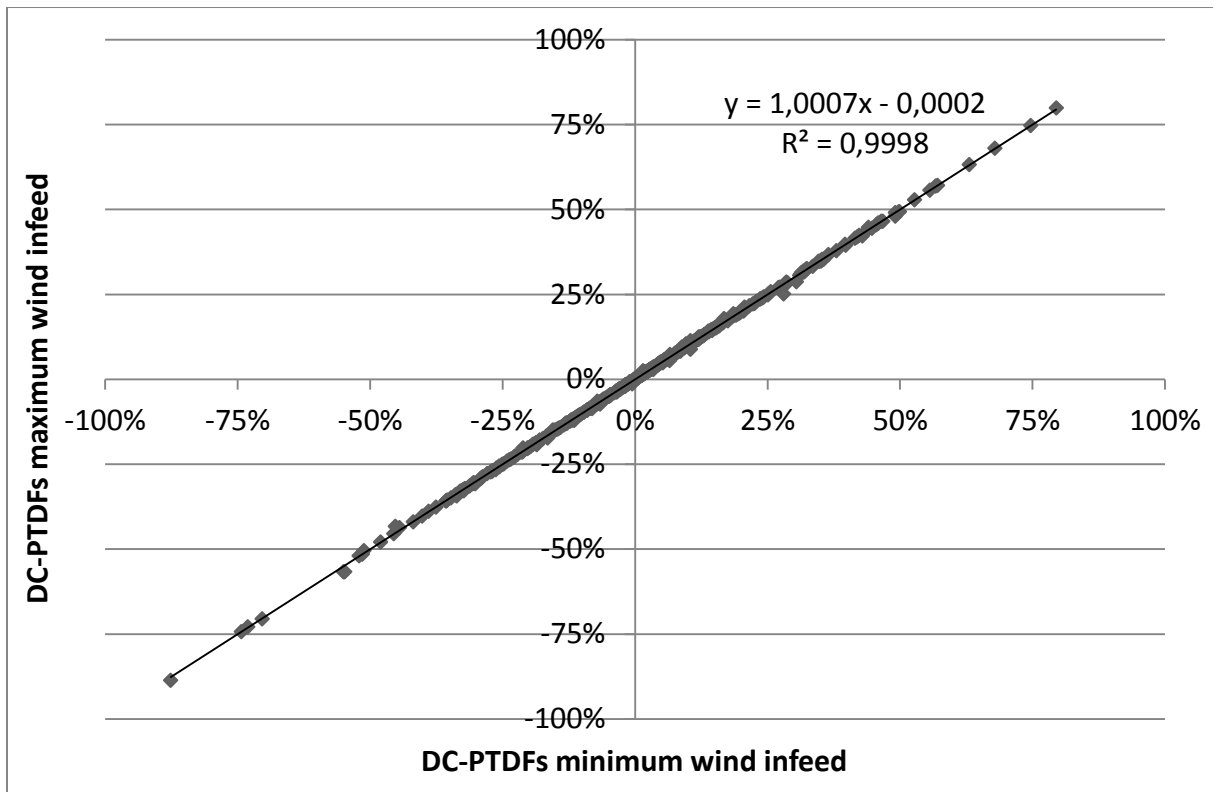


Figure 6: Comparison of DC PTDFs for wind scenarios minimum and maximum

An analysis of the load flows on intra-regional transmission lines or between individual buses reveals large deviations for all combinations of scenarios (for a comparison of line utilization for the clusters wind min and max see Figure 9 in the appendix). Most deviations between the load flows occur for generator buses having high wind (or photovoltaic) generation capacity.

4.4 Impacts on NTCs

NTC for a representative hour

To analyse the effects of RES-generation and load pattern, we first calculate a NTC for a representative system state. For the average vertical load level of 43.8 GW, the average wind feed-in of 9.2 GW and the average photovoltaic feed-in of 5.7 GW we find a NTC of 10 GW for a transaction from DE_N to DE_S.¹²

Focus on wind infeed

Figure 7 shows the resulting NTCs for selected clusters with a wind feed-in from 0.7 up to 31.8 GW. The NTCs between the market zones DE_N and DE_S vary from 8.9 to 10.2

¹² As the German power system is characterized by an excessive supply in the North of Germany and a North-South congestion problem, NTCs for transactions from DE_S to DE_N are not considered in this paper.

GW. The results indicate an increasing maximum exchange program between DE_N and DE_S with increasing wind infeed. At first glance this seems not to be logical, but can be explained by the fact that NTCs are not only impacted by wind generation, but rather by load and generation pattern and cross border flows, as we analyse actual system states. More clarity is provided by an analysis of the components of NTCs.

- First, the consideration of actual demand and generation situations comes along with a varying BCE.¹³

Thereby, the increase of wind generation is identified as an indirect driver of an increasing BCE as high wind infeed results in relative lower national power prices and higher export flows from DE_S especially to France, Switzerland and Austria.¹⁴ Or stated in other words: increasing wind generation results in changed cross border exchanges and consequently increases the BCE, which in turn causes a higher NTC.

- Second, an increase of wind infeed results in a higher utilization of the tie lines between DE_N and DE_S and thus leads to a decrease of the additional exchange capacity ΔE . Nevertheless the increase of BCE (due to the changes in exchanges, see explanation above) overcompensates the decrease of ΔE .

The main driver of this result is the unbalanced utilization of tie lines between the considered market zones. In hours with low wind generation demand has to be met by thermal capacities. Important shares of the remaining nuclear capacities are located in DE_S while modern coal plants are located especially in western Germany along the zonal border in DE_N.

This results in bi-directional load flows between both market zones (see Figure 4, scenario "wind min"). As the BCE is given by the sum of load flows on the tie lines (cf. formula 4), a lower BCE results in hours characterised by low wind generation and bi-directional North-South flows while a higher BCE results in hours with high wind generation and one-directional North-South flows.

¹³ The base case exchange (BCE) for the considered transaction between DE_N and DE_S is given by the sum of the base case power flows on all transmission lines connecting both market zones.

¹⁴ Note: Transit and loop flows via Netherlands and Czech Republic are not considered here.

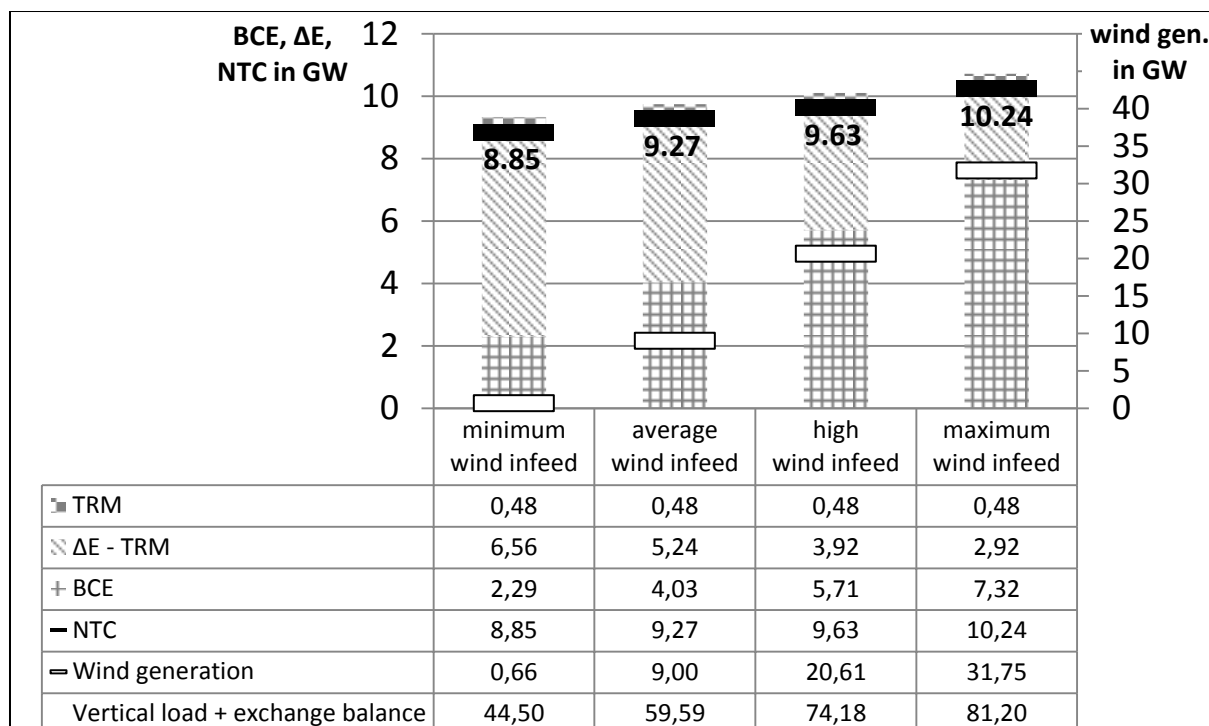


Figure 7: Impact of wind infeed and vertical load level on NTCs (PV infeed = 0)

Focus on PV infeed

Due to meteorological characteristics, more than 60% of photovoltaic capacity is located in DE_S. To study the effects of photovoltaic generation on the NTC we analyse three further typical clusters differentiated by their photovoltaic generation (no, average and high PV infeed).

An increase of photovoltaic infeed correlates with a decrease of local vertical load levels especially in DE_S. Figure 8 shows that an increasing photovoltaic generation and corresponding excessive supply in DE_S results in a negative BCE or South-North load flow. This effect is lowered by an increasing wind generation.

Furthermore an increasing photovoltaic generation correlates with an increase of the additional exchange capacity ΔE between DE_N and DE_S. Or to be more precise: increasing photovoltaic infeed “works” against the common flow direction North-to-South, which is mainly caused by wind generation and modern coal plants in the northern regions. Thus, in hours according to cluster 7 (cf. table 4) solar production located in southern Germany has a stabilising effect on the transmission network.

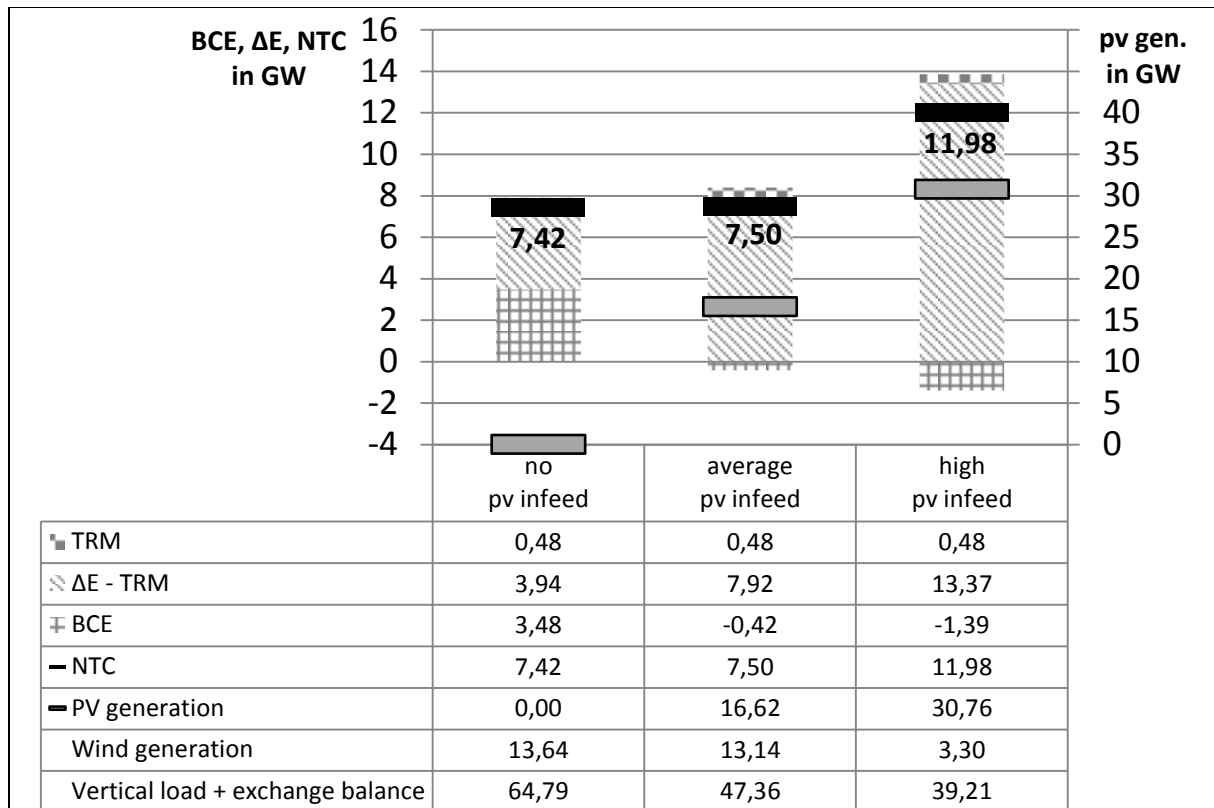


Figure 8: Impact of vertical load level, wind and pv infeed on NTCs

4.5 Implications for effectiveness of market splitting in Germany

The main drivers of congestions in Germany are on the one hand the fluctuating RES-generation and on the other hand the spatial separation notably between wind power plants and load centres. While the variations of PTDFs are negligible for the tie lines, the analysis of load flows indicates high differences on intra-regional transmission lines. We also show that the NTC between the two possible German market zones strongly depends on RES-generation, cross border flows and demand pattern.

For the effectiveness of market splitting (in Germany), the last point is of high importance. Depending on vertical load levels and RES-generation patterns, the NTCs are within a range from 7.4 to 12 GW.

Introducing market splitting with a fixed NTC of e.g. 10 GW would have a negative impact on effectiveness: in hours with underestimation of the NTC, the trading possibilities between the connected market zones would be unnecessarily reduced and in hours with an overestimation, the system security would be compromised as excessively high trading activities would intensify and not relieve the German congestion situation.

In the longer term, the NTC between the considered market zones is also influenced by grid extension as the corresponding increase of the grid's transfer capacity influences the load flow pattern. Furthermore the expansion of renewable capacities (especially

offshore wind) results in a changed generation pattern which can induce additional bottlenecks. In this regard, changes in international trading activities are also of importance. Periodical reviews of the zonal delimitation are therefore a key issue to ensure the effectiveness of market splitting.

For the purpose of energy market modelling, variable NTCs should be taken into account, especially when analysing the effects of introducing market splitting. While the German TSOs already incorporate the effects of wind generation when determining transfer capacities (C-Function for import and export flows from/to BeNeLux, France and Switzerland), transfer capacities are kept constant in most energy market models (cf. WEIGT ET AL. 2010, BURSTEDDE 2013 or NEUHOFF ET AL. 2013). Within our analysis we showed, that the components of the NTC (BCE and ΔE) strongly depend on RES generation. A higher wind infeed correlates with an increasing BCE and decreasing ΔE . In contrast a higher photovoltaic infeed especially in the southern regions correlates with an decreasing BCE and increasing ΔE . Since a further increase of photovoltaic capacities especially in southern Germany is to be expected, intermittent photovoltaic generation patterns should also be considered when computing transfer capacities in future.

5 Final remarks

This paper analyses the impacts of intermittent RES feed-in, demand pattern and the corresponding exchanges on load flows, PTDFs and NTCs. The corresponding implications for a fictitious market splitting scenario for Germany are thereby of specific interest. We therefore set up an integrated approach to model the European power system and its impacts on the German power system. The variability of generation and load patterns is considered by a clustering approach that allows the computation of power system sensitivities for representative system states.

We find a remarkable impact of wind feed-in especially in the North of Germany on load flows intensifying the North-South congestion problem till 2015.

The results regarding PTDFs suggest that for the purposes of energy market modelling the utilization of only one single PTDF-matrix does not cause major errors.

The calculation of NTCs for a fictitious splitting of the German power market into two bidding zones reveals a high dependency of the results on the combination of demand pattern, RES infeed and cross border flows. The results imply that the effectiveness of market splitting strongly depends on the considered NTC (between market zones). Based on these results we argue that NTCs in dependency of wind and solar production should be implemented when it comes to the introduction of market splitting in Germany and when the benefits of zonal pricing are analysed within model calculations as well.

Further research should focus on the investigation of flow based market coupling between German bidding zones. Thereby our findings imply that RES and demand pattern as well as the unbalanced utilization of transmission lines and bi-directional load flows among the zonal border would impact the flow gate capacities.

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Appendix

A.1 Used indices, parameters and variables

Indices and Sets	Description
H_n	Set of data points and considered hours respectively
h	Index of considered hours
S_n	Set of clusters or disjoint subsets
z, z'	Index of zones
a, b	Index of transmission lines for contingency analysis
i, j	Index of connecting transmission lines between zones
Parameters	Description
x_h	Vector of the hourly transmission flows on considered tie lines
Decision Variables	Description
μ_n	Geometric centroid of the data points that has to be minimized

A.2 Additional analyses

Table 5: Vertical load level + exchange balance, RES infeed and NTCs in MW for resulting clusters

Cluster	Cluster elements	Smallest centroid distance				Cluster mean value							
		Vertical Load + Exchange Balance	Wind	PV		ΔE	BCE	TTC	TRM	NTC	Vertical Load + Exchange Balance	Wind	PV
12	464	31,595	6,047	0	3,396	7,321	10,717	-480	10,237	40,938	6,337	5,008	
7	694	39,213	3,297	30,761	13,852	-1,391	12,461	-480	11,981	41,969	4,490	24,524	
11	941	44,502	659	0	7,044	2,287	9,331	-480	8,851	44,124	3,778	2,727	
3	878	45,322	5,568	0	5,963	4,573	10,536	-480	10,056	51,954	6,174	2,305	
2	645	46,253	893	0	8,157	2,262	10,419	-480	9,939	46,232	3,940	2,009	
4	614	47,356	13,140	16,624	8,401	-423	7,978	-480	7,498	51,286	10,666	20,694	
6	779	49,121	4,552	0	4,992	4,517	9,509	-480	9,029	49,889	5,125	2,333	
9	872	51,146	5,425	0	5,676	5,021	10,697	-480	10,217	53,882	6,867	1,375	
8	681	59,592	9,000	34	5,716	4,030	9,746	-480	9,266	52,007	9,730	4,622	
1	670	61,190	13,636	0	4,416	3,481	7,897	-480	7,417	62,040	17,974	2,537	
5	746	74,179	20,607	0	4,403	5,706	10,108	-480	9,629	60,135	18,351	3,493	
10	752	81,196	31,747	0	7,530	4,923	12,453	-480	11,973	64,814	18,491	1,399	

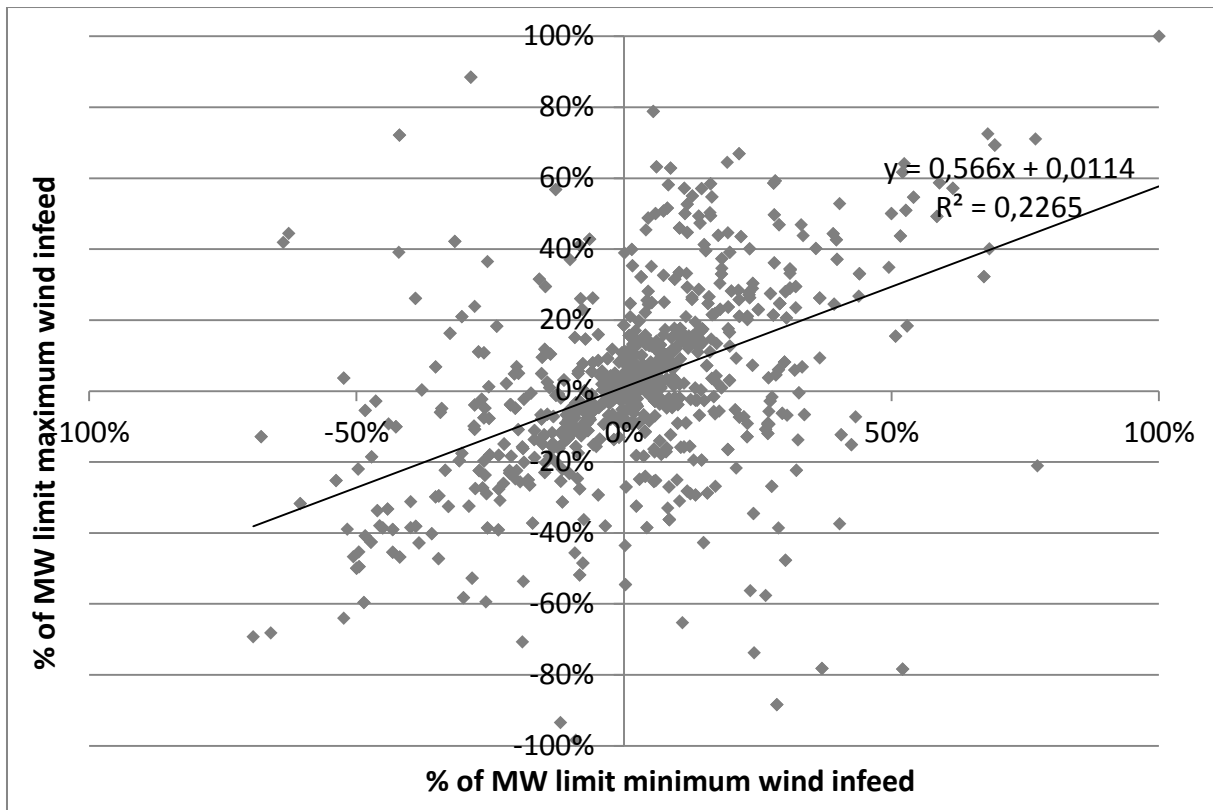


Figure 9: Comparison of line loadings for wind scenarios minimum and maximum